414 Nicollet Mall
Minneapolis, MN 55401

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November 24, 2021

—Via Electronic Filing—

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

RE: PETITION
TRANSMISSION COST RECOVERY RIDER
DOCKET NO. E002/M-21-___

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Petition for approval of 2021-2022 Transmission Cost Recovery Rider revenue requirements and the resulting adjustment factors by customer class.

Portions of Attachments 4, 4A, 4C, 4D, and 4F contain protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b), Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a) and are marked as "NOT PUBLIC." The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy.

Attachments 4A, 4C, 4D, and 4F provided with the NOT PUBLIC version of this filing contain information classified as trade secret pursuant to Minn. Stat. § 13.37 for the above-noted reasons and are marked as "NOT PUBLIC" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment 4A:

1. **Nature of the Material**: The AMI Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the third quarter of 2019 and updated in third quarter 2021.

Attachment 4C:

1. **Nature of the Material**: Attachment 4C is an internal assessment summaries that the Company has designated as Trade Secret information in their entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released.
2. **Authors:** This summary was prepared by Business Systems and Sourcing employees and their representatives in 2017, in conjunction with the Company's review of hardware and software needs for its Advanced Metering Infrastructure (AMI) and Field Area Network (FAN) projects, respectively.
3. **Importance:** This Attachment contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because these overall analyses derive independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.
4. **Date the Information was Prepared**: 2017

Attachment 4D:

1. **Nature of the Material**: Attachment 4D is an internal assessment summary that the Company has designated as Trade Secret information in its entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released..
2. **Authors**: This summary was prepared by Major Products & Programs Sourcing employees and their representatives in 2019.
3. **Importance**: This Schedule contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected

bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because this overall analysis derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret.

4. **Date the Information was Prepared**: This assessment was prepared in second quarter of 2019.

Attachment 4F:

1. **Nature of the Material**: Attachment 4F is an internal assessment summaries that the Company has designated as Trade Secret information in their entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released.
2. **Authors:** This summary was prepared by Business Systems and Sourcing employees and their representatives in 2017 (Schedule AMI 11) and 2015 (Schedule FAN12), in conjunction with the Company's review of hardware and software needs for its Advanced Metering Infrastructure (AMI) and Field Area Network (FAN) projects, respectively.
3. **Importance:** This Attachment contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because these overall analyses derive independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.
4. **Date the Information was Prepared**: 2015

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document, and served copies of the summary on the parties on the attached service list.

If you have any questions regarding this filing please contact Martha Hoschmiller at (612) 330-5973 or martha.e.hoschmiller@xcelenergy.com or me at (612) 330-5941 or holly.r.hinman@xcelenergy.com.

Sincerely,

/s/

HOLLY HINMAN
REGULATORY MANAGER

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2021AND 2022, TRACKER TRUE-UP, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. E002/M-21-___

PETITION AND COMPLIANCE FILING

OVERVIEW

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission this Petition for approval of proposed 2022 Transmission Cost Recovery (TCR) Rider revenue requirements of approximately $104.5 million and the corresponding TCR adjustment factors. This is an increase of $22.6 million compared to the 2020 revenue requirement of approximately $81.9 million.[1]

The Company has embarked on a long-term strategic plan to transform our distribution system to advance the efficiency and reliability of service and to safely integrate more distributed resources into our system. The Company's investments in its distribution system will make the grid smarter and more responsive, increase system visibility and control, and enable expanded customer options, all system-wide benefits that can lead to increased service quality, faster outage restoration, and overall reductions in energy use and related emissions. We are in the process of building an advanced electric grid that is more resilient and provides more tools and options for customers. In addition, our investments in transmission infrastructure continue to be critical in bringing renewable energy to the markets we serve.

At a high level, we propose to recover through the 2021-2022 TCR Rider:

[1] The final 2020 revenue requirements are pending a Commission Order. See Docket No. E002/M-19-721.

- Costs associated with distribution-grid modernization projects previously certified by the Commission and eligible for TCR cost recovery, as follows:
  - *Advanced Distribution Management System (ADMS)*
  - *Advanced Metering Infrastructure (AMI)*
  - *Field Area Network (FAN),*
  - *Residential Time of Use (TOU) Pilot,* and
  - *Advanced Planning Tool (APT) - LoadSEER.*
- Costs associated with transmission projects previously approved for TCR Rider recovery.

In the Company's recently filed electric multi-year rate plan (MYRP), we propose to recover through base rates costs related to transmission projects forecasted to be in-service as of December 31, 2021 that are currently recovered through the TCR Rider.[2] Due to the anticipated length of time until final rates will be implemented in the general rate case, we propose to continue recovery of these projects through the TCR Rider until final rates are implemented. These projects are not included in our interim rate request, so there will be no double-recovery between interim rates and the TCR Rider during the pendency of the case. This approach to the timing of when cost recovery for projects transitions from the TCR Rider to base rates is consistent with what was approved by the Commission in conjunction with the Company's last implemented MYRP in Docket No. E002/GR-15-826.

The increase in 2021-2022 revenue requirements compared to 2020 is primarily driven by the addition of new Distribution-Grid Modernization projects and the in-servicing of the Huntley–Wilmarth project at the end of 2021, though the increased costs are offset somewhat by an increase in MISO Regional Expansion Criteria and Benefits (RECB) credits in 2021 and 2022 compared to 2020.

If our Petition is approved as proposed, the average residential customer using 675 kWh of electricity per month would be charged approximately $3.90 per month through the TCR Rider adjustment factor. This is an increase of $1.47 per month compared to the current TCR Rider adjustment factor.

On August 28, 2020, the Company made a compliance filing in Docket No. E002/M-20-680 to outline preferred procedural paths forward regarding rider recovery for the costs associated with the Advanced Grid Intelligence and Security (AGIS) investments certified in the Integrated Distribution Plan (IDP) proceeding, as required by Order Point 13 of the Commission's July 23, 2020 ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND

[2] See Docket No. E002/GR-21-630.

CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS. The Company submits this TCR Rider Petition consistent with the procedural schedule proposed in that filing.

Xcel Energy respectfully requests the Commission approve:

- TCR Rider recovery of the Distribution-Grid Modernization projects;
- TCR Rider recovery of the transmission projects;
- 2021-2022 revenue requirements of $104,536,270;
- The resulting TCR adjustment factors by class to be included in the Resource Adjustment on bills for Minnesota electric customers for the 12 months beginning June 1, 2022;
- The ability to recalculate the adjustment factor for implementation in compliance based on the timing of the Commission's decision; and
- The proposed tariff revisions and customer notice.

Our Petition is structured as follows:

- Background;
- TCR Eligible Projects;
- 2021-2022 TCR Revenue Requirements and Adjustment Factors;
- TCR Variance Analysis Report;
- Removal of Internal Labor Costs;
- True-Up Report and Tracker Balance; and
- Proposed Tariff Sheet and Customer Notice.

We include a Table of Contents detailing the attachments included in support of this Petition.

I. SUMMARY OF FILING

Pursuant to Minn. Rule 7829.1300, Subp. 1, a one paragraph summary of our filing accompanies this Petition.

II. SERVICE ON OTHER PARTIES

Pursuant to Minn. Stat. § 216.17, subd. 3, we have electronically filed this document with the Commission. Pursuant to Minn. R. 7829.1300, subp. 2, copies of the summary of this filing have been served on the parties on Xcel Energy's miscellaneous electric service list.

III. GENERAL FILING INFORMATION

Pursuant to Minn. R. 7829.1300, subp. 3, the Company provides the following information.

A. Name, Address, and Telephone Number of Utility

Northern States Power Company, doing business as:
Xcel Energy
414 Nicollet Mall
Minneapolis, MN 55401
(612) 330-5500

B. Name, Address, and Telephone Number of Utility Attorney

Shubha Harris
Principal Attorney
Xcel Energy
414 Nicollet Mall, 401 - 8th Floor
Minneapolis, MN 55401
(612) 215-4517

C. Date of Filing and Proposed Effective Date of Rates

The date of this filing is November 24, 2021. The Company proposes the updated TCR adjustment factors be included in the Resource Adjustment line on the Company's retail electric billing rates effective the first day of the month following the Commission's Order approving this Petition. The proposed adjustment factors have been calculated with an assumed implementation date of June 1, 2022 to allow for the required 60 day notice prior to a rate or tariff change in addition to a six-month procedural schedule consistent with the proposal made by the Company in Docket No. E002/M-20-680. Should the Commission approve this Petition after June 1, 2022, we propose to recalculate the adjustment factors for implementation in compliance based on the timing of the Commission's decision.

D. Statutes Controlling Schedule for Processing the Filing

Minn. Stat. § 216B.16, Subd. 1 allows a utility to place a rate change in effect upon 60-days' notice to the Commission. Minn. Stat. § 216B.16, Subd. 7b (the Transmission Statute) allows for recovery, through an automatic adjustment mechanism of charges, the Minnesota jurisdictional costs of certain new transmission facilities, distribution facilities and planning investments that support grid modernization efforts, and certain Midcontinent Independent Transmission System Operator (MISO) charges associated with regionally planned transmission projects.

Since no determination of Xcel Energy's general revenue requirement is necessary, Commission Rules define this filing as a "miscellaneous filing" under Minn. Rule 7829.0100, Subp. 11. The accounting process that we use to track revenues and costs and record the differences in the TCR Rider Tracker account comply with Accounting Standards prescribed under Minn. Stat. § 216B.10. Pursuant to Minn. Rule 7829.1400, initial comments on a miscellaneous filing are due within 30 days of filing, with replies due 10 days thereafter.

E. Utility Employee Responsible for Filing

Holly Hinman
Regulatory Manager
Xcel Energy
414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401
(612) 330-5941

IV. MISCELLANEOUS INFORMATION

The Company will serve a copy of the Petition summary on those persons on the electric utility general service list. Pursuant to Minn. Rule 7829.0700, we request that the following persons be placed on the Commission's official service list for this matter:

Shubha M. Harris	Lynnette Sweet
Principal Attorney	Regulatory Administrator
Xcel Energy	Xcel Energy
414 Nicollet Mall, 401 - 8th Floor	414 Nicollet Mall, 401 - 7th Floor
Minneapolis, MN 55401	Minneapolis, MN 55401
shubha.m.harris@xcelenergy.com	regulatory.records@xcelenergy.com

Any information requests in this proceeding should be submitted to Ms. Sweet at the Regulatory Records email address above.

V. BACKGROUND

In 2005, the Transmission Statute was enacted, authorizing the Commission to approve a tariff mechanism for an automatic annual adjustment of charges for costs associated with eligible utility investments in transmission facilities, and in 2008 this statute was amended to allow inclusion of the costs of certain regional transmission facilities as determined by MISO.

The Commission's November 20, 2006 Order in Docket No. E002/M-06-1103 approved the Company's TCR Rider tariff, which combined recovery of eligible projects under the Renewable Statute and the Transmission Statute in one annual automatic adjustment mechanism.

Since 2006, the Company's TCR Rider mechanism has been modified several times to allow recovery of additional costs subsequently authorized by the Minnesota Legislature. The Commission's March 20, 2008 Order in Docket No. E002/M-07-1156 approved recovery of greenhouse gas infrastructure costs incurred for the replacement of circuit breakers that contain sulfur hexafluoride (SF6). The Commission's June 25, 2009 Order in Docket No. E002/M-08-1284 approved recovery of RECB revenues and costs. In 2013, the Transmission Statute was modified to authorize TCR Rider eligibility of projects located in other states that have been approved by the regulatory commission of the state in which the new transmission facilities are to be constructed if those projects are determined by MISO to benefit the utility or integrated transmission system.

In 2015, the Transmission Statute was further modified to allow for the cost recovery of distribution facilities and planning investments that support Distribution-Grid Modernization efforts. Such projects must be certified by the Commission under Minn. Stat. § 216B.2425 in order to be eligible for rider recovery. The Commission's September 27, 2019 Order in Docket No. E002/M-17-797 approved TCR Rider recovery of the ADMS project, the first Distribution-Grid Modernization project to be certified as part of the Company's first Biennial Grid Modernization Report originally filed in 2015 (Docket No. E002/M-15-962). The Commission subsequently certified additional Distribution-Grid Modernization projects – specifically, the TOU Pilot in its August 7, 2018 Order in Docket No. E002/M-17-775 and AMI, FAN, and LoadSEER in its July 23, 2020 Order in Docket No. E002/M-19-666. Additionally, the Commission's September 27, 2019 Order in Docket No. E002/M-17-797 and July 23, 2020 Order in Docket No. E002/M-19-666 established new requirements for future AGIS project cost recovery.[3] In this Petition, we request recovery of costs related to the additional certified projects, and provide information required by the Commission's recent applicable orders.

[3] See Order Point Nos. 14 and 15 of the July 23 Order for the regulatory treatment of the APT (now referred to as LoadSEER) as distinct from the treatment of other AGIS projects.

In this Petition, we have included costs related to (1) Transmission facilities and MISO-RECB costs as authorized under the Transmission Statute and (2) Distribution-Grid Modernization facilities and planning as authorized under the Transmission Statute. We note that, while we are authorized to recover certain costs related to (1) Renewable facilities as authorized by the Renewable Statute[4] and (2) Greenhouse gas infrastructure projects, we have not included any such costs in this Petition. It has been our practice to request approval for recovery of the total costs related to any of these categories under a single recovery mechanism, the TCR Rider.

We propose to implement new TCR adjustment factors beginning June 1, 2022, calculated to recover the revenue requirement over 12 months. The Company will true-up the difference between the revenues we will continue to collect under the current TCR Adjustment Factors with the revenue requirements the Commission approves in this TCR proceeding.

We also discuss in this filing how we propose to treat costs for projects currently being recovered through the TCR Rider in light of the recent MYRP filed by the Company in Docket No. E002/GR-21-630.

VI. ELIGIBLE PROJECTS

A. Projects Previously Deemed Eligible for TCR Recovery[5]

In its Order dated April 27, 2010 in Docket No. E002/M-09-1048, the Commission approved TCR Rider cost recovery for the following eligible projects under Minn. Stat. § 216B.16, Subd. 7b:

- CapX2020 Fargo–Twin Cities
- CapX2020 La Crosse-Local
- CapX2020 La Crosse-MISO
- CapX2020 La Crosse-WI

In its Order dated February 7, 2014 in Docket No. E002/M-12-50, the Commission approved TCR Rider cost recovery for the following eligible project under Minn. Stat. § 216B.16, Subd. 7b:

- CapX2020 Brookings–Twin Cities

[4] Minn. Stat. § 216B.1645, the Renewable Energy Statute, authorizes the automatic annual adjustment of charges for costs associated with utility investments or costs to comply with renewable energy mandates, including costs related to transmission facilities needed for the development of renewable energy.
[5] We note that while projects can be eligible for TCR cost recovery under Minn. Stat. § 216B.1645, we are not currently seeking recovery for any projects in the TCR Rider under that statute.

In its Order dated June 12, 2017 in Docket No. E002/GR-15-826, our last completed electric rate case proceeding, the Commission approved a Settlement wherein parties agreed that the three CapX2020 transmission projects included in the TCR Rider at that time, Fargo–Twin Cities, the three La Crosse segments, and Brookings–Twin Cities, should remain in the rider through the 2016 through 2019 MYRP in lieu of rolling the projects into base rates. No costs associated with these projects are currently recovered through base rates.[6]

In its Order dated January 17, 2017 in Docket No. E002/M-15-891, the Commission approved TCR Rider cost recovery for the following eligible projects under Minn. Stat. § 216B.16, Subd. 7b:

- Badger–Coulee (also known as La Crosse–Madison)
- CapX2020 Big Stone–Brookings

In its Order dated September 27, 2019 in Docket No. E002/M-17-797, the Commission approved TCR Rider cost recovery for the following eligible project under Minn. Stat. § 216B.16, Subd. 7b:

- ADMS Distribution-Grid Modernization project

The ADMS project was initially certified by the Commission in the June 28, 2016 Order in Docket No. E002/M-15-962. We note that some costs related to software and the GIS model improvement portion of the ADMS project were included in base rates in our last concluded electric rate case proceeding in Docket No. E002/GR-15-826. See Attachments 8A and 8B for details of the ADMS project costs included in base rates through 2021.

In Docket No. E002/M-19-721, the Company requested TCR Rider cost recovery for the following project under Minn. Stat. § 216B.16, Subd. 7b:

- Huntley-Wilmarth

A Commission Order in that docket is pending.

[6] Final rates were implemented on October 1, 2017 as approved in the Commission's September 29, 2017 Order in Docket No. E002/GR-15-826.

B. New Projects Eligible for TCR Recovery

1. AGIS Investments

In its Order dated July 23, 2020 in Docket No. E002/M-19-666, the Commission certified the following components of the Company's Advanced Grid Intelligence and Security (AGIS) Initiative:

- Advanced Metering Infrastructure (AMI)
- Field Area Network (FAN)

We request TCR Rider recovery of the certified AMI and FAN projects.

Our AMI and FAN initiative will deploy advanced meters to all of our Minnesota customers and a two-way "field" communications network across our Minnesota service area that will assist in connecting the meters with our head-end systems. AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that is capable of secure two-way communication between Xcel Energy's business and operational data systems and customer meters. FAN is a secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems. We provide full project information in support of rider eligibility in Attachment 4, including information in compliance with the Commission's Orders in Docket Nos. E002/M-17-797 and E002/M-19-666.

2. Residential Time of Use (TOU) Pilot

In its Order dated August 7, 2018 in Docket Nos. E002/M-17-775 and E002/M-17-776, the Commission certified the Residential Time of Use (TOU) Pilot Distribution Grid Modernization project.

Though certified in 2018, we have not included costs related to the TOU Pilot prior to 2022 in this TCR Rider request because a portion of those costs were included in our MYRP in Docket No. E002/GR-15-826. We removed TOU Distribution and Business Systems costs from the recently filed MYRP in Docket No. E002/GR-21-630 consistent with the removal of the other Distribution-Grid Modernization projects.

This pilot is intended to provide certain residential customers with pricing specific to the time of day energy is used. The pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods where the system is experiencing low load conditions. Price incentives that shift load away from peak may reduce or avoid the need for system investments in fossil fuel plants that serve peak electric load.

The pilot was developed partially in response to customer and stakeholder feedback about the benefits of alternative rate designs as developed in a prior regulatory proceeding. Through the pilot, the Company will study the impact of rigorously designed price signals with technology-enabled data on customer usage patterns for a subset of customers. The Company will share learnings about the effectiveness of these techniques to inform future consideration of a broader Time of Use rate deployment in Minnesota, which will be possible for more customers as we roll out AMI meters across our entire service territory.

We provide more project cost and implementation detail in Attachment 3.

3. Advanced Planning Tool (APT) – LoadSEER

In its July 23, 2020 Order in Docket No. E002/M-19-666, the Commission certified the Advanced Planning Tool (APT) – LoadSEER. In this Petition, we request TCR Rider recovery of the certified LoadSEER project.

Given market trends, widespread changes to our grid, and our forecasting software's lifecycle, it has become essential to implement a new, more capable, and dynamic forecasting tool to support our distribution system planning processes. Such a tool is necessary to meet our planning and regulatory requirements, provide our customers with incremental benefits, and meet the needs of customers who are increasingly exercising more choice around their use of energy from our grid – choosing Distributed Energy Resources (DER) and beneficial electrification that can make load forecasting a much more complex undertaking than it was only a few years ago.

It is necessary for our distribution planning tools to accommodate additional data granularity to better assess how technologies interact with the grid and how they change distribution system needs. Further, the Commission implemented distribution planning analyses and reporting requirements the Company must meet. These requirements include conducting scenario forecasting and assessing Non-Wires Alternatives (NWA) for certain system upgrade needs we identify in our planning process. Finally, our previous tool and its hosting server were out of date – and its vendor would no longer be supporting it in the near future. Considering these factors, the time was ripe to implement a new solution. We therefore initiated a solicitation and assessment process, selected LoadSEER as our preferred APT, and sought certification of it under Minn. Stat. § 216B.2425. We provide full project information in support of rider eligibility in Attachment 5, including the extensive information in compliance with the Commission's Orders in Docket Nos. E002/M-17-797 and E002/M-19-666.

4. *Transmission Projects*

The Company does not propose TCR Rider recovery of any new transmission projects in this Petition.

C. ADMS Project Compliance

In its Order dated September 27, 2019 in Docket No. E002/M-17-797, the Commission approved TCR Rider recovery of the ADMS Distribution-Grid Modernization project but required that any future cost recovery filing for ADMS investments include an ADMS business case and a comprehensive assessment of qualitative and quantitative benefits to customers. This information is provided as Attachment 2.

In compliance with the September 27 Order, we have filed ADMS annual reports on January 24, 2020 and January 25, 2021, reporting on actual 2019 and actual 2020 data, respectively. Our next annual report will be filed by January 25, 2022 and will include actual expenditure and project progress data through calendar year 2021.

D. Potential Future TCR Rider Costs

In its July 31, 2020 Order in Docket No. E002/M-19-685, the Commission first adopted a long-term goal to use the Hosting Capacity Analysis (HCA) in the interconnection process's Fast Track Screens and directed the Company to work with stakeholders to refine its HCA toward that long-term goal. The Order also outlined several other potential future use cases for the Company to examine and report on in its 2020 HCA report – including maintaining the HCA as an initial indicator for the interconnection process and integrating the HCA or using the HCA to augment various processes in the Minnesota Distributed Energy Resource Interconnection Process (MN DIP). In our 2020 HCA in Docket No. E002/M-20-812, we discussed our analysis and outlined a potential roadmap to maturing the HCA and MN DIP processes, including cost and timeline estimates for future use cases. In its November 9, 2021 Order accepting our 2020 HCA report, the Commission reiterated its long-term goal for the HCA and ordered the Company to continue its work with stakeholders on the potential futures it initially outlined in its July 31, 2020 Order.

To the extent the Company moves forward or the Commission directs the Company to pursue one or more of the future use cases, a key question will be the appropriate path for cost recovery. That should not be an impediment, however, to our moving forward with such use cases in the near future in part because the legislature has authorized utilities to include such costs in the TCR Rider.[7] Minn. Stat. § 216B.16, subd. 7b (b)(4) authorizes the Commission to allow a utility to recover "costs associated with distribution planning required under section 216B.2425." In other words, should the Commission determine the costs are appropriate for the Company to incur as improvements to the HCA analysis under Minn. Stat. § 216B.2425, subd. 8, it may also authorize the recovery of such prudently incurred costs through the TCR Rider. We expect future cost recovery for the HCA could begin in the 2024-2025 timeframe.

VII. REVENUE REQUIREMENTS AND TCR ADJUSTMENT FACTORS

In this section, we provide the 2021-2022 revenue requirements and the resulting TCR adjustment factors for the TCR Rider projects and charges identified in this Petition. For illustrative purposes, we have assumed an effective date of June 1, 2022 and have calculated the adjustment factors over a 12-month period. We propose to recalculate the final TCR adjustment factors to recover the 2021-2022 revenue requirements based on the timing of the Commission's decision if it occurs after June 1, 2022. We will provide the updated adjustment factor calculations as part of a compliance filing after the Commission issues an Order.

The 2021-2022 revenue requirements we propose to recover from Minnesota electric customers are approximately $104.5 million, an increase of $22.6 million compared to the $81.9 million of 2019-2020 revenue requirements used to calculate the adjustment factors which were provisionally implemented on March 1, 2020.[8] Attachments 8 and 9 provide the supporting revenue requirements based on actual information through June 2021 and projected TCR Tracker activity from July 2021.[9] Attachment 10 provides our projected TCR Rider revenues, calculated by customer class based on

[7] We note that we have not included costs related to any future use cases in our pending general rate case.
[8] *See* Docket No. E002/M-19-721. IN THE MATTER OF THE PETITION OF XCEL ENERGY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2019 AND 2020, AND REVISED ADJUSTMENT FACTORS. *Petition* (November 15, 2029) and *Order* (February 21, 2020).
[9] We note that revenue collections are actual through June 2021.

forecasted State of Minnesota billing month sales and the proposed TCR adjustment factors.[10]

A. Proposed TCR Adjustment Factors

Costs being recovered through the TCR Rider are categorized into two groups, Transmission and Distribution-Grid Modernization. Transmission costs through the TCR Rider are allocated to the NSP System (Northern States Power Company Minnesota (NSPM) and Northern States Power Company Wisconsin (NSPW)), to NSPM's State Jurisdictions (Minnesota, North Dakota and South Dakota), and to the Minnesota Jurisdiction Classes (Residential, Commercial and Industrial (C&I) Non-Demand, and C&I Demand) based on the demand allocation factors approved in the Company's last electric rate case (Docket No. E002/GR-15-826). This approach is consistent with the Commission Orders in past TCR proceedings requiring that the adjustment factors be calculated using the state jurisdictional allocators approved in the Company's last electric rate case.[11] Distribution-Grid Modernization costs recovered through the TCR Rider are allocated to NSPM's State Jurisdictions (Minnesota, North Dakota and South Dakota) using direct assignment, or use a general, intangible, customer count, or meter count allocation. In order to allocate to the Minnesota Jurisdiction Classes (Residential, Commercial and Industrial (C&I) Non-Demand, and C&I Demand), the distribution allocation factors approved in the Company's last electric rate case (Docket No. E002/GR-15-826) are used.

Transmission and Distribution-Grid Modernization expenses are allocated to classes differently, therefore we have separately allocated Transmission and Distribution-Grid Modernization investments in the TCR Rider. We have calculated the Customer Group Weighting by taking the percentage of total transmission project dollars and the total Distribution-Grid Modernization project dollars as a percent of the 2022 revenue requirements, excluding the carryover balance. We then divided the combined average allocation for each customer class by the corresponding sales allocation percentage for the same customer class. The transmission demand, distribution, and sales allocation percentages were established in Xcel Energy's last

[10] The rate design for these factors was approved in the Commission's November 20, 2006 Order in Docket No. E002/M-06-1103 and the October 21, 2011 Order in Docket No. E002/M-10-1064. The rate design was amended in Docket No. E002/GR-12-961 where the Commission ordered that system coincident summer peak allocators should be used to allocate transmission costs, and again in Docket No. E002/GR-13-826 when the Streetlighting Class was removed.

[11] See the Department's September 7, 2016 Response Comments in Docket No. E002/M-15-891 and the Commission's January 17, 2017 Order approving this approach. See also Ordering Point No. 1 of the Commission's August 14, 2014 Order in Docket No. E002/M-13-1179.

approved electric rate case, Docket No. E002/GR-15-826. See Attachment 11 for the details of these calculations.

Within each of the non-demand metered classes of service, these allocated costs are recovered through a per kWh charge. We determine the per kWh charge for each class by applying a class-specific allocation factor to the Minnesota jurisdiction average per kWh TCR cost. The transmission demand allocator and distribution allocator are based on the sales forecast as approved in our last electric rate case (Docket No. E002/GR-15-826). The resulting TCR adjustment factors recover the current costs.

For the demand metered class, the TCR adjustment factors are determined similarly; however, the factor to be billed is instead determined by using forecast year demands instead of sales to yield a per kW factor.

Table 2 below shows our proposed TCR adjustment factors and overall revenue requirements compared to the TCR adjustment factors which were implemented on March 1, 2020.

Table 2: Adjustment Factor Comparison

	2019-2020 Provisionally Implemented	**2021-2022 Proposed**
Total Revenue Requirements	$81,883,541	$104,536,270
Residential Rate/kWh	$0.003607	$0.005783
Commercial Non-Demand/kWh	$0.003185	$0.004545
Demand/kW	$0.982	$1.081

An average residential customer using 675 kWh of electricity per month would see an increase on their bill of approximately $1.47 per month compared to the current TCR residential adjustment factor.

The proposed TCR adjustment factors are calculated assuming they are effective June 1, 2022. If the timing of a decision in this proceeding does not allow for a June implementation date, the Company requests that adjustment factors be recalculated to recover the 2021-2022 revenue requirements over the 12 months subsequent to the Commission Order to more closely match cost recovery with the eligible 2021-2022 costs, similar to the treatment authorized in past TCR Rider orders.

B. TCR State of Minnesota Revenue Requirements

The detailed 2021-2022 Minnesota jurisdictional revenue requirements by project in support of the proposed TCR adjustment factors are included in Attachment 15. Transmission Statute project revenue requirements, including Distribution-Grid Modernization projects, are calculated using the guidance provided in Minn. Stat. § 216B.16, subd. 7b(b)(2) and the Commission's prior related orders.

1. *Transmission Statute Revenue Requirements*

The Transmission Statute requires certain information be provided in support of our request. For ease, Table 3 below lists where the statutory filing requirements are located throughout this filing:

Table 3: Statutory Filing Requirements

Requirement	Authority	Location in Filing
a description of and context for the facilities included for recovery	Minn. Stat. § 216B.16, Subdivision 7b[c] 1	Attachments 1 - 5 contain the project descriptions for projects the Company believes are eligible for recovery through the TCR Rider.
a schedule for implementation of applicable projects	Minn. Stat. § 216B.16, Subdivision 7b[c] 2	Attachment 6 contains an implementation schedule for each of the Transmission projects identified in Attachment 1. Schedules for Distribution-Grid Modernization projects can be found in Attachments 2 - 5.
the utility's costs for these projects	Minn. Stat. § 216B.16, Subdivision 7b[c] 3	Attachments 7A and 7B show the capital expenditure forecast for each identified project. Capital expenditures are accumulated from project inception through December 31, 2026.
a description of the utility's efforts to ensure the lowest costs to ratepayers for the project	Minn. Stat. § 216B.16, Subdivision 7b[c] 4	The Company has made extensive efforts to ensure the lowest cost to ratepayers for the proposed TCR-eligible projects. These efforts are discussed in the Project Descriptions in Attachments 1 - 5.
calculation to establish that the rate adjustment is consistent with the terms of the tariff established in paragraph [b]	Minn. Stat. § 216B.16, Subdivision 7b[c] 5	Attachment 11 contains the calculation of the proposed TCR adjustment factors by customer class. We provide the details of these calculations under the Cost Recovery section of this Petition.

2. *MISO Revenue Requirements*

In addition to allowing the Company to recover the costs of transmission projects being constructed by the NSP System, the Transmission Statute allows TCR Rider recovery of charges billed under a federal tariff (such as the MISO Tariff) associated with other transmission expansions being constructed in the MISO region by other utilities. The actual charges through June 2021 and projected charges from July 2021 from the regional transmission projects included in the MISO Transmission Expansion Plan (MTEP) cost allocations are presented in Attachment 14.

Expenses based on Schedule 26 and 26A of the MISO Tariff for 2021 are forecast to be \$136,168,578 million and for 2022 are forecast to be \$134,568,263.[12] The Company expects these charges to be offset by 2021 Schedule 26 and 26A revenues from MISO tariffs associated with regional rate recovery of NSP System project investments of \$141,634,499 million in 2021 and \$147,701,794 in 2022.

The forecast results in net estimated Schedule 26 and 26A revenues to NSP that are more than expenses (negative revenue requirements) of -\$5,465,871 (total NSP System) for 2021 and -\$13,133,530 for 2022. The net revenues were further adjusted by an allocation to NSPW and other Company jurisdictions to arrive at the Minnesota jurisdiction of net RECB revenue requirements of -\$3,995,005 in 2021 and -\$9,607,189 in 2022. This is shown in Attachments 8 and 14 as negative revenue requirements in each year. The Company believes the Schedule 26 and Schedule 26A cost recovery through the TCR Rider has been calculated consistent with the Transmission Statute, and it includes the MVP Auction Revenue Rights (MVP ARR) as we indicated in our June 19, 2015 Reply Comments in Docket No. E999/AA-14-579.

We have identified the MVP ARRs in Schedule 26/26A, including forecasted revenue, and separately identified both actual and forecasted amounts for Schedule 37 and 38 line items as recommended by the Department of Commerce (DOC) in Docket. No. E002/M-19-721.[13] In addition, we have identified the Federal Energy Regulatory Commission (FERC) audit revenues and expenses in 2021. See Attachment 14.

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[12] Pending complaints filed with FERC described further in Section VII. B. 3.

[13] We expect the pending Order will also require the inclusion of this information.

3. *Impact on TCR Rider of Pending FERC Complaint*

a. Complaint Background

FERC has taken a number of actions related to the return on equity (ROE) that MISO transmission owners (TOs) charge for regionally shared facilities. We provide a description of the resolved and still pending proceedings below. Future true-ups through the TCR may be necessary as additional FERC decisions are finalized, and we will update the Commission on these issues in future TCR Rider petitions.

In November 2013, a group of industrial customers in the MISO region filed a complaint asking FERC to reduce the 12.38 percent return on equity (ROE) used in the transmission formula rates of jurisdictional MISO transmission owners, including NSPM. On September 28, 2016, FERC issued an Order based on the methodology originally adopted in FERC Opinion 531, a case involving the base ROE for transmission owners in the New England ISO, approving a 10.32 percent ROE in September 2016, applicable for a refund period from November 12, 2013 to February 10, 2015 (the first refund period) and prospectively from the date of the order. The total prospective ROE is 10.82 percent, which includes a 50 basis point adder for Regional Transmission Organization (RTO) membership.

In February 2015, an intervenor in the original ROE complaint filed a second complaint proposing to reduce the MISO region ROE, resulting in a second period of refund from February 12, 2015 to May 11, 2016 (the second refund period). In June 2016, based on the Opinion 531 methodology, the administrative law judge recommended an ROE of 9.70 percent, the midpoint of the upper half of the discounted cash flow (DCF) range.

On April 14, 2017 the D.C. Circuit Court of Appeals vacated and remanded Opinion 531. The court decision found that FERC had not established that the prior ROE was unjust and unreasonable, and that FERC also failed to adequately support the newly approved ROE.

In October 2018, FERC issued an ROE order that addressed the D.C. Circuit's actions. Under a new proposed two-step ROE approach, FERC indicated an intention to dismiss an ROE complaint if the existing ROE falls within the range of just and reasonable ROEs based on equal weighting of the Discounted Cash Flow model, Capital Asset Pricing Model, and Expected Earnings model. FERC proposed that, if necessary, it would then set a new ROE by averaging the results of these models plus a Risk Premium model.

FERC subsequently made preliminary determinations in a November 2018 Order that the MISO TO's base ROE in effect for the first complaint period (12.38 percent) was outside the range of reasonableness, and should be reduced. FERC's preliminary analysis using the proposed ROE approach indicated a base ROE of 10.28 percent for the first complaint period, compared to the previously ordered base ROE of 10.32 percent. FERC ordered additional briefings on the new methodology, which were filed in February and April 2019.

On March 21, 2019, FERC announced a Notice of Inquiry (NOI) seeking public comments on whether, and if so how, to revise ROE policies in light of the D.C. Circuit Court decision. FERC also initiated an NOI on whether to revise its policies on incentives for electric transmission investments, including the RTO membership incentive. The comment periods concluded in August 2019.

b. FERC Action Since our Last TCR Petition

In November 2019, FERC issued an Order adopting a new ROE methodology and setting the MISO base ROE at 9.88 percent (10.38 percent with the RTO adder), effective September 28, 2016 and for the first refund period. FERC also dismissed the second complaint.

In December 2019, MISO TOs filed a request for rehearing. Customers also filed requests for rehearing claiming, among other points, that FERC erred by dismissing the second complaint without refunds. FERC accepted the requests for rehearing in January 2020; however, it is uncertain when FERC will act on the requests or any other pending matters related to the 2019 NOIs.

In January 2020, complainant-aligned parties filed a protective petition for review of FERC's November 2019 order with the D.C. Circuit. Also in January 2020, FERC issued tolling orders granting the requests for rehearing of the November 2019 order solely for the purpose of further consideration.

In May 2020, FERC issued an order on the merits of the various requests for rehearing of its November 2019 decision. FERC modified its ROE methodology to raise the MISO base ROE to 10.02 percent (10.52 percent with the RTO adder). FERC also upheld its prior decision to deny the second complaint without refunds.

In June 2020, several parties including complainant-aligned parties and utility-aligned parties filed requests for rehearing of FERC's May 2020 Order. In June and July 2020, the MISO TOs and several utility-aligned parties filed petitions for review of FERC's November 2019 and May 2020 orders at the D.C. Circuit.

In July 2020, complainant-aligned parties filed an additional protective petition for review in the D.C. Circuit. In July 2020, complainant-aligned parties filed an additional protective petition for review in the D.C. Circuit.

Additionally, in June 2020, the D.C. Circuit issued a decision in an unrelated proceeding, Allegheny Defense Project v. FERC, which held that FERC's longstanding use of tolling orders to extend FERC's deadline to act on the merits of requests for rehearing is improper. The effect on this decision on tolling orders previously issued by FERC, including the tolling orders issued in January 2020 regarding requests for rehearing of FERC's November 2019 decision on the MISO ROE complaints, is currently unclear.

Appeals of FERC's 2019 and 2020 Orders on the two ROE complaint proceedings have been consolidated at the U.S. Court of Appeals for the D.C. Circuit. Oral arguments were scheduled to occur November 18, 2021.

In FERC NOI proceeding regarding modifications to the ROE 50-basis point adder for ROE participation, FERC has received comments but has not yet issued any policy or rule modifications.

c. Impact of FERC Actions on the TCR Rider

Refunds for the first refund period, based on the September 2016 FERC Order, were settled with MISO in May 2017, and the impact of those refund settlements were included in the 2017 carry-over balance and the resulting calculation of the 2018 revenue requirements in our October 16, 2019 compliance filing in Docket No. E002/M-17-797.

Refunds for the first refund period and the period from November 21, 2019 – December 31, 2019 based on the November 2019 FERC Order authorizing a 9.88 percent base ROE (10.38 percent with the adder) were settled with MISO in early 2020, and the impact of those refund settlements are included in the 2020 actual RECB line item in this Petition. Resettlements to the 10.02 percent ROE (10.52 percent with the RTO adder) for 2019 and 2020, approved by FERC in the May 2020 Order, were processed during 2020. Additional resettlements have been processed during 2021 for the first refund period, as well as the period from September 28, 2016 - December 31, 2016. The remaining open periods are also expected to be resettled to the 10.52 percent ROE by early 2022. For all currently unsettled periods, we have not included an amount since the amount is not known. The TCR tracker filed in next year's TCR Petition will update for the final, actual resettlements in the 2021 and 2022 RECB line item.

In calculating the 2021-2022 TCR revenue requirement, we applied the currently authorized 10.52 percent MISO ROE, which includes the RTO adder, for 2022 activity. However, future adjustments to the TCR Tracker may be necessary pending the appeals at the D.C. Circuit Court or any other FERC actions. We will keep the Commission informed of any additional outcomes in these proceedings.

4. *Other Costs Included in Revenue Requirement Calculations*

In addition to inclusion of statutory requirements in our project revenue requirements models, the Company also includes costs approved by the Commission in previous TCR Rider Orders. For example, we use a projection of construction expenditures and costs for the 2021-2022 forecast period. Allowable costs other than those previously mentioned include property taxes, current and deferred taxes and book depreciation. Attachment 8 summarizes the projected revenue requirements for 2021-2022. Attachment 15 shows the revenue requirement calculations by project.

5. *Distribution-Grid Modernization Project O&M Costs*

As shown in Attachment 15, and consistent with our approved cost recovery in Docket No. E002/M-17-797, we have included operating and maintenance (O&M) costs for the Distribution-Grid Modernization projects in the TCR Rider. As discussed in more detail below, we have excluded internal labor costs from TCR Rider recovery. O&M and capital expenses for these projects are combined in the project revenue requirements total shown in Attachments 8 and 9. We have not included O&M costs for any of the transmission projects recovered through the TCR Rider. Base assumptions are included in Attachment 12.

a. Interchange Agreement Allocator

For the purpose of determining the State of Minnesota jurisdictional revenue requirements for production and transmission plant investment, the Company uses a demand allocator, which reflects the sharing of costs between the Company and NSPW pursuant to the Interchange Agreement. Consistent with the allocation method approved by the Commission in our 2013 TCR Rider proceeding, we have used budget Interchange Agreement allocators for 2021.[14] Any resulting over- or under-recovery from customers as a result of the use of the budget demand factors will be reflected in our next TCR Rider Petition that will use actual allocators as they are available.

b. Open Access Transmission Tariff (OATT) Calculation

We established the TCR transmission revenue requirement by also reflecting the revenue offset provided by wholesale transmission services under the MISO Tariff. The OATT revenue credit captures a portion of the revenue the Company receives from third-party transmission customers who are charged FERC-jurisdictional MISO tariff rate for use of the Company's transmission system. Our approach to this issue is consistent with the approach approved in the 2008 TCR petition, Docket No. E002/M-07-1156. This is separate from the revenue credit for MISO Schedule 26 and 26A RECB revenues.

The forecast period used to calculate the transmission formula rate under the MISO Transmission and Energy Market Tariff (TEMT) is consistent with the forecast period used to develop costs recovered under our TCR adjustment factors. In addition, the basis for both the MISO revenues and Transmission revenue requirements is a 13-month average plant balance.

Additionally, pursuant to Commission Order, we include Capital Work in Progress (CWIP) in the OATT revenue credit calculation only for those projects that have not been designated by FERC as regionally shared projects or are not included in the MISO tariff (transmission serving generation or distribution). The CapX2020 La Crosse-Local project is included in the MISO tariff but has not been designated by FERC as a regionally shared project. Therefore, an OATT revenue credit has been applied to this project. Further, we exclude any projects designated as RECB projects, since all RECB costs and Company revenues are included in the TCR Rider. To apply the OATT revenue credit to RECB projects would be reducing project revenue requirements for revenue received from others twice, once through RECB revenues and once through the OATT revenue credit. The OATT revenue credit is shown in Attachment 13.

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[14] Docket No. E002/M-13-1179, ORDER APPROVING 2014 TCR RATES AS MODIFIED, APPROVING 2013 TRACKER ACCOUNT, AND REQUIRING COMPLIANCE FILING, August 14, 2014. The 2019 Interchange Agreement allocators were approved by FERC on May 1, 2019 in Docket No. ER19-1340. The final 2020 allocators will be filed with FERC in early 2020, but the budgeted 2020 allocators are included in our recently filed Minnesota electric rate case.

6. *Accumulated Deferred Income Taxes (ADIT)*

The Company calculated the 2022 revenue requirements using the alternative ADIT treatment discussed in our May 25, 2018 Supplemental Reply Comments in Docket No. E002/M-17-797, which conforms to our understanding of the proration formula in IRS regulation section 1.167(1)-1(h)(6). Under this treatment we have:

1. Treated each forecast month as a test period since the revenue requirements in riders are calculated monthly. This allows the monthly ADIT balance to be reset to its un-prorated beginning balance and only the monthly activity receives the proration.
2. Then applied a mid-month convention for the proration factors in each month.
3. Removed ADIT from the beginning-of-month and end-of-month rate base average, since the proration is itself a form of averaging. These treatments reduce the proration impact to the ratepayers in these rider mechanisms significantly.

We believe that this treatment minimizes customer impact while still maintaining the significant deferred tax benefits provided to our customers. This treatment requires the ADIT prorate to be embedded in the rate base calculation rather than separated as a line item. However, we provide Attachment 16 to show how ADIT proration impacts the total revenue requirement for 2021 and 2022. Since we do not propose to implement the 2021-2022 adjustment factors until June 2022, the ADIT prorate is only included for June – December 2022.

As can be seen from Attachment 16, the impact on customers of our proposed ADIT treatment is de minimis. The total impact of ADIT proration on the TCR Rider under this methodology is $208 of $104.5 million in total revenue requirements for the 2022 calendar year.

We note that the Department agreed with this proration methodology in their October 16, 2020 Comments in our 2019-2020 Transmission Cost Recovery (TCR) Rider proceeding (Docket No. E002/M-19-721).

7. *Rate of Return*

With the exception of the return on equity (ROE), all other components of the rate of return approved in our last completed Minnesota electric rate case are shown on Attachment 12 and have been used to determine the return on CWIP and rate base. Allowable costs include the overall rate of return on investments, property taxes, current and deferred taxes, and book depreciation.

In compliance with Order Point 3 of the Commission's September 27, 2019 Order in Docket No. E002/M-17-797 and Order Point No. 4 of the Commission's September 30, 2019 Order in Docket No. E002/M-17-818, we have calculated the TCR Rider revenue requirements using an ROE of 9.06 percent.

8. ADMS Costs in Base Rates

The ADMS costs included in base rates as a result of the 2016-2019 MYRP approved in Docket No. E002/GR-15-826 have been removed from our TCR Rider revenue requirements through 2021 as shown on Attachments 8, 8A, and 8B. The removal reflects updates as discussed in Information Request No. DOC-13 in Docket No. E002/M-17-797 and attached to the Department's April 2, 2018 Comments. We note that in the pending MYRP docket, the ADMS costs previously included in base rates have been included as part of the TCR Rider removal. Therefore, beginning with the 2022 rate case test year and the implementation of interim rates on January 1, 2022, the base rates no longer include any costs included in the TCR Rider.

VIII. TCR VARIANCE ANALYSIS REPORT

Order Point 4 of the Commission's Order dated April 27, 2010 in Docket No. E002/M-09-1048 states:

> *In setting guidelines for evaluating project costs going forward, the TCR project costs recovered through the rider should be limited to the amounts of the initial estimates at the time the projects are approved as eligible projects, with the opportunity for the Company to seek recovery of excluded costs on a prospective basis in a subsequent rate case. A request to allow cost recovery for project costs above the amount of the initial estimate may be brought forward for Commission review only if unforeseen and extraordinary circumstances arise on the project.*

Below we provide a brief discussion of factors contributing to cost changes relating to several of the projects since our last TCR filing.

A. Huntley–Wilmarth

The Company is currently forecasting an approximate reduction in total capital costs of 22 percent or $15.8 million, excluding internal labor, for the Huntley–Wilmarth project. This reduction is primarily related to an overall reduction in Company overhead costs to the project. Forecasted estimates were originally based on 2017 estimates; however, the realized actual cost of these overhead rates during the construction of the project are significantly less than estimated. Additionally, we reduced the budget for the remainder of the construction schedule as we experienced savings in contractor bids, route alignment adjustments during the permitting process that reduced costs, and efficient outage coordination. Finally, the reduction can also be attributed to overall construction savings in easement costs, actual materials cost, strategic competitive contractor bidding, and construction oversight. We forecast that this project will be placed in service in December 2021.

We note that in the Certificate of Need (CON) proceeding, we showed project costs in both 2016 dollars and escalated dollars. The CON Order notes a final project cost of $140.1 million in 2016 dollars, which equates to $155.8 million in escalated dollars. Since the Company's share of the Huntley–Wilmarth project is 50 percent, the final cost benchmark for the purposes of TCR cost recovery is $77.9 million. The Company's current forecast is significantly less than this amount.

B. La Crosse–Madison

Although the La Crosse–Madison project was placed in-service in December 2018, the project is still showing some expenditures in 2023. The project's current forecasted cost at completion has increased approximately 1%, or $2.1 million excluding internal labor, compared to our forecasted cost at completion in our last TCR Petition. This cost variance is due to continuing landowner and condemnation proceedings. Even with this relatively small increase, the project's forecasted cost at completion does not exceed the applicable cost cap. We currently estimate the that the La Crosse–Madison project's cost at completion will be $173.7 million excluding internal labor, which is less than the $179.1 million final estimated project cost presented in our June 3, 2016 Reply Comments in Docket No. E002/M-15-891.

IX. REMOVAL OF INTERNAL LABOR COSTS

We have excluded internal labor costs from the projects that qualify for the Rider under both the Transmission Statute and Distribution-Grid Modernization Statute. Table 4 below shows the cumulative amount of internal labor costs that have been removed through 2022.

Table 4: Internal Labor Expenditures Removed

Project	Through 2022
CapX2020 Brookings – Twin Cities	$21,175,382
CapX2020 Fargo – Twin Cities	$17,047,608
CapX2020 La Crosse (WI, MISO, and Local)	$21,111,943
CapX2020 Big Stone – Brookings	$9,375,749
La Crosse – Madison	$2,619,804
Huntley–Wilmarth	$3,203,296
ADMS	$10,043,838
APT – LoadSEER	$146,207
TOU Pilot	$596,466
AMI	$10,420,663
FAN	$2,205,956

X. RATE CASE TREATMENT

In the Company's recently filed MYRP, we propose to roll into base rates the projects that will be placed in service as of December 31, 2021. Specifically, the Company proposes to roll into base rates Big Stone-Brookings, CapX2020-Brookings, CapX2020-La Crosse Local, CapX2020-La Crosse MISO, CapX2020-La Crosse-WI, CapX2020-Fargo, La Crosse-Madison, and Huntley–Wilmarth, coincident with the implementation of final rates in the MYRP filed on October 25, 2021.[15] However, due to the anticipated length of time until final rates will be implemented at the conclusion of the rate case, we propose to continue recovery of these projects through the TCR Rider where they have been recovered since construction of these projects began.

We believe this a reasonable approach since (1) we employed a similar approach when we transferred significant capital investments from the Metro Emissions Reduction Project (MERP) Rider, the Renewable Energy Standard (RES) Rider, and State Energy Policy (SEP) Rider to base rates; (2) continued rider recovery will result in a better matching of costs to recovery while ensuring against overlapping recovery of project costs; and (3) our interim rate request will be lower. Our MYRP also assumes certain other capital investments either eligible for rider recovery or already in a rider

[15] Docket No. E002/GR-21-630

will continue to be recovered through the rider. In addition, this approach is consistent with our proposed treatment of TCR Rider projects in our 2015 rate case, where projects remained in the TCR Rider until the implementation of final rates, though ultimately the projects remained in the rider as a result of a Settlement.

We have structured our rate request in this way to reduce the interim rate increase and mitigate any potential for overlapping recovery. The interim rate revenue requirement was adjusted to remove the rate base and cost components associated with the roll-in of TCR Rider projects to eliminate any potential double-recovery.

XI. PROPOSED TARIFF SHEET AND CUSTOMER NOTICE

A. Proposed Revised Tariff Sheet

Attachment 17 includes both redline and clean versions of our TCR Rider tariff sheet updated to show the proposed TCR adjustment factors by customer class. The tariff provides that the TCR adjustment factors are included in the Resource Adjustment and that factors will be applied to customer bills upon Commission approval. We propose an effective date of June 1, 2022; however, the tariff sheet and revised TCR factors will not be made effective until after the Commission acts on this Petition.

B. Proposed Customer Notice

The Company plans to provide notice to customers regarding the change in the TCR Adjustment Factors reflected in their monthly electric bill. The following is our proposed language to be included as a notice on the customers' bill the month the TCR Adjustment Factors are implemented:

> *This month's Resource Adjustment includes an increase in the Transmission Cost Recovery Adjustment (TCR), which recovers the costs of transmission and distribution investments, including delivery of renewable energy sources to customers. The TCR portion of the Resource Adjustment is $0.005783 per kWh for Residential Customers; $0.004545 per kWh for Commercial (Non-Demand) customers; and $1.081 per kW for Demand billed customers.*

We will work with the Consumer Affairs Office regarding this proposed customer notice in advance of implementation.

CONCLUSION

The Company respectfully requests the Commission approve this Petition. Specifically, we request the Commission approve:

- TCR Rider inclusion of and costs related to four additional certified Distribution-Grid Modernization projects: Residential TOU Pilot, AMI, FAN, and APT – LoadSEER;
- costs related to the transmission projects and the ADMS project previously approved for TCR Rider recovery;
- 2021-2022 TCR Rider revenue requirements of $104.5 million;
- the resulting TCR adjustment factors by class to be included in the Resource Adjustment on bills for Minnesota electric customers for the 12 months beginning June 1, 2022;
- the ability to recalculate the adjustment factor for implementation in compliance based the timing of the Commission's decision; and
- the proposed tariff revisions and customer notice.

Dated: November 24, 2021

Northern States Power Company

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

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

IN THE MATTER OF THE PETITION OF NORTHERN STATES POWER COMPANY FOR APPROVAL OF THE TRANSMISSION COST RECOVERY RIDER REVENUE REQUIREMENTS FOR 2021AND 2022, TRACKER TRUE-UP, AND REVISED ADJUSTMENT FACTORS

DOCKET NO. E002/M-21-___

PETITION AND COMPLIANCE FILING

SUMMARY OF FILING

Please take notice that on November 24, 2021 Northern States Power Company, doing business as Xcel Energy, submitted to the Minnesota Public Utilities Commission a Petition for approval of the 2021-2022 Transmission Cost Recovery (TCR) Rider revenue requirements of approximately $104.5 million and revised TCR adjustment factors to be included in the Resource Adjustment on customer bills for electric customers in Minnesota. We propose to recover costs related to four additional certified distribution-grid modernization projects in addition to projects that have been previously recovered through the TCR Rider.

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Transmission Cost Recovery Rider
Eligible Projects

Attachment 1 lists the projects previously approved for recovery in the TCR Rider and describes new projects proposed to be included in the 2021 TCR Rider.

I. Transmission Projects

A. Transmission and Renewable Projects Previously Approved as Eligible for TCR Cost Recovery Under Minn. Stat. 216B.16, Subd. 7B

In its Order dated April 27, 2010 in Docket No. E002/M-09-1048, the Commission approved TCR Rider cost recovery for the following eligible projects:

- CapX2020 Fargo – Twin Cities
- CapX2020 La Crosse

In its Order dated February 7, 2014 in Docket No. E002/M-12-50, the Commission approved TCR Rider cost recovery for the following eligible project:

- CapX2020 Brookings – Twins Cities

In its Order dated January 17, 2017 in Docket No. E002/M-15-891, the Commission approved TCR Rider cost recovery for the following eligible projects:

- La Crosse – Madison (also referred to as Badger – Coulee)
- Big Stone – Brookings 345 kV Line

B. Eligibility of New Transmission Projects:

In Docket No. E002/M-19-721, the Company requested eligibility determination for the following project.

- Huntley-Wilmarth 345 kV Transmission Line

A Commission Order is pending, affirming rider eligibility of the project.

The Company is not seeking eligibility determination for any new transmission projects this year.

Efforts to Ensure Lowest Cost to Ratepayers

All major materials (steel structures, switches, transformers, breakers and conductors) and construction labor for this project will take advantage of contracts that have been negotiated by the Company's sourcing group. These contracts were negotiated based on Xcel Energy system-wide use of materials and components resulting in lowest cost.

C. Efforts to Ensure Lowest Cost to Ratepayers

The transmission projects currently included in the TCR rider are joint projects between utilities and, with the exception of the La Crosse – Madison project, are part of the CapX2020 Initiative. Many of the CapX2020 planning benefits described below are benefits also experienced by coordinating with another utility for projects such as the La Crosse – Madison project. Working with other utilities helps to ensure cost-effective construction and a less piecemeal approach to transmission project planning.

In particular, the CapX2020 group of utilities established a coordinated regional approach to addressing both regional and community reliability needs, and longer-term growth. To ensure cost-effective implementation of the CapX2020 projects, the Company, through its participation in the CapX2020 Initiative, provided for a prudent means of developing the projects. The CapX2020 Initiative was formed to meet the growing transmission needs of all utilities in the region. By coordinating regional planning, the region's utilities are able to develop complete solutions to regional transmission needs instead of disjointed solutions that could lead to duplicative transmission facilities being built. Further, by acting as a group, the CapX2020 Utilities obtain improved efficiency in permitting, routing, scheduling, material purchasing and overall project development. Overall, the Company's participation in the initiative allows us to lessen our costs and achieve greater benefits from the projects due to the strength and size of the organization. For example, by working together, the CapX2020 Utilities have been able to develop a comprehensive set of alternatives for improvement of the transmission system, as opposed to crafting disjointed solutions that would result from individual utility solutions.

In addition, working together within the regulatory environment to jointly file applications for permits in all of the affected jurisdictions allows regulators to more fully understand the scope, benefits and impacts of the projects and not be subjected to numerous separate filings by individual utilities on separate projects that may, at times, work at cross purposes. The joint approach taken by the Company and the other participating CapX2020 utilities is a prudent way to proceed with developing the projects in order to spread the costs among a broad array of utilities. An investment of approximately $1.8 billion for all of the projects would be difficult for any single utility to undertake. By collaborating with a number of other regional utilities, the Company is able to successfully spread its risks and balance its costs.

Finally, the Company and the participating utilities recognize that there are benefits arising from a coordinated effort in securing materials and services required to build the CapX2020 projects. As such, a joint sourcing approach has been utilized to pursue benefits in order to minimize or eliminate inter-project competition for labor and material resources, maximize leverage on vendors and specification standardization, establish a common Request for Proposal (RFP) process to present one "CapX2020 face" to the market and eliminate inefficiencies, maximize inter-project flexibility where possible for services. For example, utilizing a joint sourcing process across the projects creates a spend volume asset. This volume consolidation and early RFP activity allows manufacturers and suppliers the ability to plan fabrication in advance of the delivery needs. This approach works to avoid the premium costs associated with orders outside of the lead time and typically garners more attractive pricing when the suppliers, manufactures and contractors are able to advance plan their production schedules or field resources.

II. Distribution-Grid Modernization Projects

A. Distribution-Grid Modernization Project Previously Approved as Eligible for TCR Cost Recovery Under Minn. Stat. 216B.16, Subd. 7B (5)

In its Order dated September 27, 2019 in Docket No. E002/M-17-797, the Commission approved TCR Rider cost recovery for the following eligible project:

- Advanced Distribution Management System (ADMS)

The September 27 Order requires the Company to include in any future cost recovery filing for ADMS investments and ADMS business case and a comprehensive assessment of qualitative and quantitative benefits to customers. We provide this information in Attachment 2.

B. Eligibility of New Distribution-Grid Modernization Projects

The Company requests TCR Rider recovery for the following projects:

- Residential Time of Use (TOU) Pilot,
- Advanced Metering Infrastructure (AMI),
- Field Area Network (FAN), and
- Advanced Planning Tool (APT) - LoadSEER.

See Attachments 3 – 5 for full project descriptions and additional project details.

III. Renewable Statute Projects

A. Eligibility of New Renewable Statute Projects

We are not seeking the determination of eligibility of any new renewable projects at this time.

IV. Greenhouse Gas Projects

A. Eligibility of New Renewable Statute Projects

We are not seeking the determination of eligibility of any new greenhouse gas projects at this time.

ADVANCED DISTRIBUTION MANAGEMENT SYSTEM

The Commission's September 27, 2019 Order in the Company's 2017-2018 Transmission Cost Recovery Rider (TCR) proceeding required the Company to:[1]

> *include in any future cost recovery filing for [Advanced Distribution Management System] (ADMS) investments an ADMS business case and a comprehensive assessment of the qualitative and quantitative benefits to customers.*

This Attachment provides support for our Advanced Distribution Management System (ADMS) cost recovery request, consistent with the above requirement. We again include business case-type information for the ADMS investment and note that the qualitative benefits to customers and functionality description of ADMS is unchanged from our most recent project description included with our 2019 TCR Petition[2]. We also discuss the ADMS project status and overall budget.

I. INTRODUCTION AND OVERVIEW OF ADMS

ADMS is the foundational software platform for operational hardware and software applications used to operate the current and future distribution grid. ADMS is foundational because it provides situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. Specifically, ADMS acts as a centralized decision support system that assists the control room, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS does this by utilizing the as-operated electrical model and maintaining advanced applications which provide the Company with greater visibility and control of an electric distribution grid that is capable of automated operations. ADMS incorporates Distribution Supervisory Control and Data Acquisition (D-SCADA) measurements and advanced application functions with an enhanced system model to provide load flow calculations everywhere on the grid, accurately adjusting the calculations with changes in grid topology and insights from sensors. This allows the Company to improve the

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[1] See Order Point No. 6, *In the Matter of the Petition of Northern States Power Company for Approval of the Transmission Cost Recovery Rider Revenue Requirements for 2017 and 2018, and Revised Adjustment Factor*, Docket No. E002/M-17-797 ORDER AUTHORIZING RIDER RECOVERY, SETTING RETURN ON EQUITY, AND SETTING FILING REQUIREMENTS (Sept. 27, 2019).

[2] Docket No. E002/M-19-721.

monitoring and control of load flow from substations to the edge of the grid, which enables multiple performance objectives to be realized over the entire grid. Implementing ADMS will enable management of the complex interaction among outage events, distribution switching operations, advanced applications such as Fault Location Isolation and Service Restoration (FLISR) in the near-term, and also preparing the Company to implement future advanced applications like Distributed Energy Resource Management System (DERMS).

The Geospatial Information System (GIS) data improvements aspect of our ADMS initiative is necessary to enable ADMS, and also furthers grid modernization efforts more broadly related to Distributed Energy Resources (DER). The asset data necessary to support a modern grid goes well beyond the data we have traditionally needed to provide reliable and adequate electric service. Our impending implementation of AMI will supplement the work done as part of our ADMS initiative by faciliting improvements to our asset connectivity model data. These underlying data improvements will also serve to reduce the amount of time that planning engineers spend preparing each feeder model for analysis. It will also help our designers validate capacity necessary for electric vehicles (EV) and help DER adoption by improving the GIS model that is used for system planning, Hosting Capacity Analysis (HCA), and potentially interconnection studies that are part of the Minnesota DER Interconnection Process (MN DIP). We outlined a conceptual asset data improvement initiative as part of our examination of several potential HCA futures the Commission directed the Company to explore.[3] At this time, we believe the asset data effort we are completing for ADMS and the improvements expected from our impending deployment of AMI will, at a minimum, reduce the amount of field asset data collection and validation necessary to support the potential HCA futures.

II. BACKGROUND

In our first Grid Modernization Biennial Report filed with the Commission on November 1, 2015 (Docket No. E002/M-15-962), we sought project certification of ADMS, which the Commission certified in its June 28, 2016 Order in that docket. The Company's first cost recovery request for ADMS was in its 2017 and 2018 TCR (Docket No. E002/M-17-797). In our Petition, we addressed the need for ADMS, customer benefits, the process for selecting the vendor, and budget information. The

[3] See Docket No. E002/M-20-812.

Commission approved recovery of revenue requirements of approximately $10.2 million in actual expenditures incremental above base rates for ADMS through 2018 in the TCR rider.

We submitted our request to recover approximately $27.2 million in forecasted ADMS capital expenses, incremental above base rates for the 2019-2020 period in our November 15, 2019 TCR Petition in Docket No. E002/M-19-721. The Commission verbally approved our requested level of cost recovery for ADMS at its October 21, 2021 hearing; the Commission's Order in that proceeding is pending at the time we drafted this filing.

The Commission has previously recognized the Company's vendor for ADMS development and implementation "was thorough and targeted to avoid unreasonable expenditures," so we do not repeat that content in this project narrative.[4] To the extent it is necessary or helpful, information about our vendor selection process can be found in Attachment 1A to the Company's initial Petition in Docket No. E002/M-17-797.

III. NEED FOR ADMS AND CUSTOMER BENEFITS

As outlined in past cost recovery requests, ADMS is a key foundational element for Grid Modernization. Once it is implemented, new grid capabilities and functionalities will be enabled that will help the Company fulfill the vision of a fully integrated advanced electric distribution grid. We outline these below, and note that these are substantially the same as what we have provided in past TCR Rider filings.

A. Qualitative Benefits

The key objectives of ADMS are to provide integrated grid preparedness, improve reliability, and to increase efficiency on the grid. Examples of how ADMS meets these objectives and a description of the qualitative customer benefits are below.

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[4] *See* September 27, 2019 Order in Docket No. E002/M-17-797. In approving the Company's ADMS request, the Commission noted that the Company's "acquisition process [for selecting a vendor with experience in developing, implementing, and supporting electric distribution real-time supervisory control and data acquisition (SCADA) and ADMS control systems] was thorough and targeted to avoid unreasonable expenditures."

Integrated Grid Preparedness. With an increasing penetration of DER forecasted, along with existing electric distribution grid impacts, it is essential to have a system that enables integration of grid technologies and functionalities. The existing electric distribution model and analysis tools available to the operators were not built to accommodate the increasing penetration of DER. ADMS allows the system to adapt by managing the complex interaction of DER, outage events, feeder switching operations and smart grid technologies in one system. This proactive approach to DER management will provide our customers with safe, reliable, and economic power.

ADMS enables the Company to transition from a passive to an active DER management approach because of the DER Management capabilities within ADMS. DER Management runs in real-time and allows operators to monitor DER with an awareness of its effect on the entire electric distribution grid. For example, operational risks associated with DER are reduced because the DER Management capabilities can display reverse power flow and the hidden load[5] at every protective device along the feeder. By knowing what DER is active in the grid and its impact, the Company can continue to incorporate customer-requested DER on the grid and still ensure safe operations.

ADMS applications are needed to provide operational assistance in the study and management of DER on the electric distribution grid. ADMS provides visibility and situational awareness of DER on the distribution grid through utilization of the real-time network model and load flow calculations. Along with this network model, several advanced analysis tools are available that will aid in increasing efficiency and accuracy of DER management and interconnection processes. This increased efficiency and accuracy will also benefit customers.

Reliability. ADMS supports operators in determining optimal solutions faster during outage restoration through utilization of the network model, load flow calculations, and advanced analysis tools. ADMS, in conjunction with automated grid components, can improve reliability and quality of service in terms of reducing outages, minimizing outage time, and enabling advanced energy efficiency. For example, operators can perform a restoration analysis that quickly provides them with options for outage restoration. Another example is a fault location tool, FLISR, which calculates the possible locations of the outage cause. Being able to determine

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[5] Load that is masked by DER and can cause trouble when performing switching operations.

optimal solutions faster during outage benefits customers by being able to restore service in a faster and more efficient manner.

In past Grid Modernization Reports and Integrated Distribution Plans (IDP) filed in Docket Nos. E002/M-17-776 and E002/M-19-666, we have discussed FLISR as an advanced application of ADMS that, in concert with field devices and proper communication, improves grid reliability and operational performance during outages. FLISR provides remote monitoring control of the field devices and involves deploying automated switching devices with the objective of decreasing the duration and number of customers affected by an individual outage. ADMS-based FLISR is beneficial because it acts as the common distribution integrated control platform for multiple corporate objectives operating in the same area. This optimizes and ensures safety during FLISR operations because there is an awareness of the impact FLISR device operations have on the grid as a whole that a stand-alone FLISR system would not have. Additionally, ADMS provides a central management scheme with the agility for dynamic reaction to distribution grid changes so FLISR devices can automatically restore customers outside the fault zone. Automatic restoration in certain circumstances is also a customer benefit. We note that we outlined our plan to implement FLISR as part of our multi-year rate plan submitted October 25, 2021 in Docket No. E002/GR-21-630.

Operational Efficiency. ADMS acts as an integrated distribution control platform that provides improved grid efficiency by enabling efficient execution of technologies on the same area of the grid through central control of automated devices. By having a system with central control, the Company can combine grid topology awareness with field automation to optimize outage response effectiveness and power quality performance on the grid. For example, distribution operators will manage multiple technologies in one ADMS system which reduces the amount of time operators spend switching between different programs, gives the ability to optimize workspaces, and increases overall efficiency in operations.[6] Another example is the improvement in operational training that ADMS provides. These training tools are necessary to efficiently transfer knowledge about operations of the electric distribution grid to new employees.

[6] Taylor, Tim and Kazemzadeh, Hormoz *Integrated SCADA/DMS/OMS: Increasing Distribution Operations Efficiency* http://assets.fiercemarkets.net/public/smartgridnews/dms_abb_02.pdf.

ADMS' integration capabilities enable ADMS to extend the value of the smart grid technology to new and emerging grid performance objectives. For instance, ADMS will use Advanced Metering Infrastructure (AMI) meters as sensors, in near real-time, to improve power flow accuracy and advanced application performance within ADMS. Full realization of smart grid technology benefits can only be leveraged in an integrated system. Currently, technologies implemented at Xcel Energy are stand-alone, so full realization of smart grid technology benefits cannot be leveraged; ADMS is an important and essential step toward integration. ADMS enables the optimization of each smart grid technology by using a single as-operated network model with accurate load flow calculations. By acting as an integrated distribution control platform, multiple objectives can be achieved in a safe and efficient manner.

Customer Satisfaction and Engagement. Reliability and information about outages is important to all customers and are a major factor in defining their relationship and satisfaction with their utility. The ADMS platform – especially when coupled with AMI – will provide the Company with more information about the nature of faults, helping us identify the cause, status, and predict the restoration time for outages. Today, we are typically unaware of an outage that occurs below the feeder level prior to customers contacting the Company to inform us that they are without power. This places the burden of reporting and engagement on the customer. With these technologies, we will provide customers with more information about service outages including more accurate estimates of restoration times.

The ADMS system, coupled with other systems such as AMI and a future DERMS, will also help integrate DER more efficiently. With more granular data we can better refine our estimations of the impact of new resources and better integrate more resources on the grid.

Safety. By using an integrated ADMS platform, the Company can ensure safe operations between different technologies operating in the same area. In addition, ADMS provides a single network model which can reduce the workforce miscommunication safety risks associated with having multiple models of the distribution system. Other safety benefits are enabled by ADMS analysis tools; for example, load flow analysis calculates and displays bidirectional load flow which gives distribution operators both visibility and situational awareness for safe operations of the distribution grid with DER present.

Cybersecurity. As the Company moves forward into the next generation of intelligent electric distribution, each facet of the electric network must be evaluated for cybersecurity risk. ADMS has incorporated zone methodologies to layer cybersecurity controls. This includes segmentation of control system communications by function and implementing advanced grid specific security processes and standards to protect, detect, respond and recover from cybersecurity risks of this foundational system. Reliable delivery of electricity is of paramount importance, protecting the integrity and security of this system is included with that responsibility.

Asset Optimization. ADMS utilizes an enhanced network model with real-time load flow calculations. This provides accurate information and representation of the distribution grid, which is necessary for strategic operational planning of existing and future assets. Optimizing the use of assets is a key strategy to keeping infrastructure costs lower, thereby helping to keep overall rates lower.

B. Quantitative Benefits

In Part A above, we speak to the many qualitative benefits including how ADMS is a foundational platform upon which process improvements and advanced applications will be layered. We are still not in a position to be able to forecast quantitative benefits of the foundational ADMS platform with precision. For example, we cannot accurately forecast the time customers applying to interconnect will save due to the increased accuracy and efficiency of ADMS. Similarly, we cannot accurately forecast at this time the impact to reliability metrics the core ADMS program will produce; we are however, able to estimate benefits from FLISR, which we do in our concurrent multi-year rate plan (MYRP).

IV. ALTERNATIVES TO ADMS

The industry is moving to ADMS to provide the capabilities necessary for a more integrated grid and the Company needs to stay at the forefront of what is expected to become the industry standard in the near future. Prior to embarking on the ADMS initiative, the Company explored alternatives, but determined there were none that were comparable. At that time, there were alternatives to obtain partial benefits, but none that comprehensively worked to secure the broad range of benefits that ADMS provides. The three approaches we considered are outlined below.

Targeted improvements: Increasing the size of cables, for example, would increase capacity on the electric distribution grid. Although this improvement could allow for an increased amount of DER, it would only serve that one objective. In contrast, an ADMS allows for an increased amount of DER in addition to enabling DER

Management. Increasing capacity on the grid, in comparison to ADMS, does not best support effective grid modernization because it fails to provide a real-time awareness of load flow which assists the Company in the management of DER.

Autonomous systems: Another way for the Company to achieve some of the benefits facilitated by ADMS is to install separate, autonomous systems that would integrate with existing SCADA and Outage Management System (OMS) systems instead of installing a fully integrated ADMS. This alternative does not provide the platform for smart grid technologies that is necessary to enable a fully integrated grid. Devices would operate on their own at individual sites in the field without awareness of each other. We have pursued implementing some autonomous systems (i.e. SmartVAR pilot,); however, these systems are isolated and are not able to work together. ADMS is the necessary integrated distribution control platform that enables safe and efficient operation of multiple corporate objectives in the same area.

Status Quo: A final alternative would be for the Company to do nothing in way of grid enhancement, maintaining the status quo of current grid capabilities. This option limits the ability to integrate higher levels of DER and other advanced technologies and limits the ability to improve grid efficiency and reliability.

ADMS is currently the only comprehensive platform that can accomplish what is necessary to implement the Company's overall Grid Modernization initiative. It provides both situational awareness and automated capabilities that sustain and improve the performance of an increasingly complex grid. ADMS enables integration of DER and other technologies in addition to improving grid efficiency and reliability. ADMS, acting as the comprehensive integrated platform for grid technologies, provides the integrated system that is imperative for a modernized grid to operate efficiently and safely.

V. CURRENT AND NEAR TERM ADMS INVESTMENTS

A. ADMS System Roll-Out To Date

The Company began detailed design for implementation of ADMS in 2016. We first examined our service territories across all of the Company's jurisdictions to assess how to best roll-out ADMS. We determined that our affiliate, Public Service Company of Colorado (PSCo), would be ideal for the initial ADMS roll-out, owing to its varied nature, increasing penetration of DER, and Commission implementation requirements.

Implementation of the ADMS platform began with detailed design and the installation of hardware and software. Testing and verification of the network impedance model and of the functionality of the core applications of ADMS followed (and continues). As part of this process, we also verify connectivity to the SCADA field devices which must interact with ADMS. ADMS software development, configuration and integration building began in 2017 across all operating companies. Testing and deployment of the ADMS software began in 2018. The software was placed into service in the PSCo jurisdiction in April 2019 and has also since been implemented in NSP.[7]

In 2019 and 2020, we installed the software, and made preparations for enabling the control centers. Specifically, we established the operator training environment and completed integrations of ADMS with other systems. In 2020, we made additional progress on the ADMS implementation – completing the software purchase, installation and configuration, and software testing – and much of the hardware, including the purchase and installation of networking equipment and operator workstations in our Metro West and Outstate control centers in Minneapolis. We also focused on field device communication testing, which has continued into 2021 – as has "tuning" of an advanced Integrated Volt Var Optimization (IVVO) model, operator and non-operator training, final technical validation, and a business readiness process that includes training and documentation of processes for our employees that will use and support ADMS.

Finally, we note that in 2021, we have been focused on going live in the various Minnesota control centers. The first control centers to go-live were Metro West and Outstate in April 2021, and then Metro East in September 2021. Going live is when our control center operators began using the ADMS system as designed – which for the first control center go-live included monitoring and control of substations, field devices, and feeders. Since the first Minnesota Control Center go-live in April 2021, the system has performed very well and has been extremely stable. We have experienced no system outages with continuous 24 hours, seven days a week usage.

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[7] The NSP Companies include Northern States Power Company Minnesota (NSPM) and Northern States Power Company Wisconsin (NSPW).

B. ADMS Network Model Build Effort

An important part of ADMS going live has been the work we have done and that we have remaining to have a valid network impedance model for at least a subset of the NSPM distribution system. With the three Minnesota control centers live and using ADMS, this is the only part of the ADMS initiative that will continue beyond 2021.

Currently, we have approximately 240 substations and 1,050 feeders in Minnesota. In our NSPM service area, there are three control centers (Metro West, Outstate, and Metro East) with each having a separate geographic area of responsibility that they operate. The initial phase of the ADMS project is to meet the network model requirements for each of the three control centers. As part of the control center go-lives, control center operators will use ADMS to control and monitor the system, which includes tasks such as responding to alarms and opening and closing feeder breakers. Beyond the initial control center go-lives, we expect to expand the capabilities of ADMS over many years, which is part of the overall journey for integrating new devices to ADMS and leveraging its capabilities to enable additional advanced functionality of ADMS, such as FLISR.

We completed the initial Network Model Build phase work for all three Control Centers required for go-live and placed the software into service. For each Control Center go-live, a unique network model is required for each Control Center's geopraphic area of responsibility (a subset of substation, field devices, and feeders the Company maintains), which included building, testing, and validating substations and field devices and the initial build of the feeders into ADMS. Each of the substations and field devices undergo a testing and validation process that is conducted prior to go-live to ensure the monitoring and control capabilities in ADMS are functioning as expected. The feeders were brought into ADMS for each of the Control Center go-lives based on the current asset information in GIS. However, a final phase of this ADMS project is contemplated to include the data collection, validation, and testing of feeders on which we have not performed these activities previously, and that are necessary to support the additional functionality of ADMS, such as FLISR.

The data strategy for the initial phases of the ADMS implementation was informed by the National Renewable Energy Lab (NREL) study we have discussed previously and also summarize here. As part of verifying and informing our future data collection strategy, we partnered with NREL and our ADMS product developer, Schneider Electric. We worked together to perform analysis regarding the evaluation of ADMS performance for different levels of system model quality. As part of this effort, we analyzed whether our planned feeder field verification strategy captured the level of information to support various levels of model quality. As a result of this work, we determined that the volume of system data being captured for each of the feeders via the field verification process could be reduced from initial estimates for ADMS purposes, which were previously incorporated into our work plan and budget.

We originally assumed that we would be bringing in the remaining substations and feeders that were not part of the initial Network Model Build over the course of several years after the Control Center go-lives. However, based on the efficiencies and maturation of completing these activities, we were able to bring all the substations and feeders that are part of the Minnesota system into ADMS as part of the Control Center go-lives. As part of this work, the full Minnesota primary distribution system is currently depicted and can be operated from ADMS.[8]

The final phase of this ADMS project is contemplated to include the data collection, validation, and testing of feeders on which we have not performed these activities previously, and that are necessary to support the additional advanced functionality of ADMS, such as FLISR. Based on refinement of our data collection strategy and plans moving forward, the 2022-2025 budget forecast (GIS category, specifically) will support these activities. We note that we also provided a conceptual estimate to do a full asset field validation process as part of the HCA futures the Commission required the Company to examine as an outcome of its 2019 HCA in Docket No. E002/M-19-685. We believe the right approach at this time for the Company and our customers is to continue with the field data validation process necessary to support ADMS and to learn from our impending AMI deployment the data we can gain through that technology before expanding our field asset data validation efforts.

C. Additional Functional Requirements Installed

In this section, we discuss the additional functional requirements installed to achieve ADMS functionality (including support for Advanced Metering Infrastructure (AMI), integration with Field Area Network (FAN), and proof of functionality for advanced FLISR and IVVO modules).

[8] Although not all of the feeders will have undergone the same data validation process.

1. AMI and FAN

Outage data gathered by the AMI meters will be used to maintain greater awareness of customer outages and aid in more expedient restoration. Advanced meters report power-out or "last gasp" events to the AMI head-end application and report a power-on event when power is restored. "Last gasp" is the final message transmitted by the meter upon detection of an outage. This information will flow from the head-end application into OMS and, as part of the integration between OMS and ADMS, will provide updates in ADMS. These power-on and power-off notifications will provide us with a more timely and accurate scope of outages without relying on customers to report them. Relatedly, restoration confirmation notifications will allow us to focus and optimize our restoration efforts on active outages, minimizing field trips where outages do not exist, also known as "Okay on Arrival" calls.

Requirements and design for this integration began in 2021, with implementation concurrent with AMI implementation, currently scheduled to begin in early 2022. The Company also intends to use a portion of AMI meters as "bellwether" sensing devices to provide near real-time power information to ADMS. Finally, AMI data will be used to create improved load profiles for planning and operations.

The FAN will provide two-way communication between field devices and for ADMS. Since the deployment of ADMS precedes AMI, the Company has been using public cellular Long-Term Evolution (LTE) technology to provide two-way communications from field devices to ADMS.

2. Proof of Functionality – FLISR and IVVO

The ADMS software functional requirements to enable the proof of functionality for FLISR and IVVO are in progress. This includes the hardware installed for the validation feeders (two FLISR and seven IVVO, with one overlapping both applications), confirming communications and performing final tests. Work remaining consists of final device integration, tuning and testing of the automatic operation of each application within ADMS. We expect to complete this final testing in 2022.

VI. PROJECT BUDGET

To ensure success and prudent spend related to the ADMS initiative, we have taken and will continue to take the following steps: engage in benchmarking with peer utilities in the industry; leverage industry leading technology experts; utilize key business partners in robust sourcing processes; establish formal internal governance structure that includes senior business leadership executives; establish rigid decision processes and financial governance including rigorous project change request and approval processes; and select an initiative level business management consultant to further support the overall governance and management of the projects.

We employ standard processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These processes are designed to ensure that the Company is both containing costs appropriately and managing expenditures on the items necessary to achieve the desired outcomes and overall reasonable costs. These standard processes have been, and will continue to be, utilized within the ADMS project and the wider grid modernization initiatives we are pursuing. These standard processes include:

- **Product Selection** through a (Request for Proposal) RFP process, as described in detail in Attachment 1A to our Petition in Docket No. E002/M-17-797, which is intended to ensure the most optimal solution for the Company's needs was selected and the price was negotiated to optimal costs to the Company.
- **Project and Initiative Governance Processes** which follow the Company's ULC (Universal Life Cycle) processes for all aspects of the project. This includes managing scope, risks, issues, milestones and financials. All changes to scope that have an impact on project costs, schedules, risk and benefits are reviewed through clearly defined levels of governance including project steering committees, AGIS Leadership, Integration Council (Cross-function Senior Leaders) and executive sponsors. This process, called Project Change Request (PCR), follows formal documentation and approval processes and limits at each level and are reviewed and documented in bi-weekly Change Board meetings with AGIS Leadership.
- **Contingency** that will be refined as the project progresses. The use of the contingency is closely managed and subject to internal approvals.

A. Budget Development

After the Commission certified ADMS and we concluded the RFP and vendor selection processes, we developed a more detailed project estimate from the pricing and contract verbiage, as well as internal labor and hardware to support the overall ADMS project. Total project costs include five key components: labor, software, hardware, GIS data collection efforts (for the Network Model Build), and contingency. Because the ADMS is being developed as one software system across the Company's enterprise system and being implemented in each specific operating company on a different timeline, the ADMS costs are allocated to specific utilities and jurisdictions.

Upon completion of detail design work, we developed a detailed implementation plan and updated our project estimates, which for Minnesota was $69.1 million of capital. We are now estimating a net lower cost of $8.1 million – or a total of $61.0 million of capital. We discuss the budget development process below, then summarize the differences in our latest capital forecast. We discuss the allocation process in Part B below.

1. Labor

The ADMS labor estimate was developed from a bottoms-up forecast of all resources required to complete the Implementation phase. The bottoms-up labor estimate includes labor costs already incurred through the detail design phase along with estimates to complete the work for the build, test and implementation phases. Labor components for the implementation phase include external vendors (Schneider, General Electric and Oracle), Xcel Energy employees, and contractors. Vendor cost estimates are based on contractual agreements with each vendor. Employee and contractors include resources from distribution, IT and program management. The employee and contractor labor forecast was based on a roll-up of all resources required to perform the project work and the estimate durations for each.

We have excluded internal labor costs from the ADMS project costs requested in the TCR.

2. Software

The software portion of the ADMS budget consists of the license agreement and various third-party infrastructure. The Schneider license agreement is a fixed cost and has been fully executed. The third-party software consists of licenses for the operating systems, databases and security products to operate and secure the ADMS system. The cost estimates were based on the number of hardware environments, servers, and processors based on existing license agreement costs with the third-party companies.

3. Hardware

Detailed system processing requirements were gathered through the RFP process as well as the contract process with the selected vendor for the ADMS system. These detailed requirements were used by the project team and the Company's infrastructure team, in conjunction with the ADMS vendor's technical experts, to determine size, scale and costs for all aspects of the infrastructure needed to adequately, securely and reliably operate the ADMS system for the Company. The types of hardware required include processors, data storage, security hardware/software, network devices such as firewalls and core switches, as well as critical data center infrastructure including power, cooling and cabling. Hardware costs have been excluded from the project revenue requirements requested in the TCR as discussed further below in the cost allocations section.

4. GIS

In order to create a GIS project budget the Company engaged in the following scoping activities:

- A gap analysis was conducted to determine the information currently available in the Company's GIS data model and what additional information is needed for ADMS to run successfully.
- Identification of changes required to the GIS data model to support ADMS.
- Identification of data that is to be captured from other sources (such as substation equipment databases) and how this will be provided to ADMS.
- Assessment of the quality of data currently held in the GIS and external sources and determine if additional data cleanup activities are required.
- Identification of data attributes that are to be field verified and updated in the GIS.

Two vendors participated in a Colorado-based data collection pilot effort in 2017. Their RFP responses provided expected costs for data collection by pole and substation. We used those per unit costs and extrapolated them, however as we discuss elsewhere in this 2021 project description, we have since refined the expected costs for the NSPM implementation.

5. *O&M Costs*

O&M costs are comprised of labor, training and communications, IT hardware and network support, and contractual software maintenance. At this time, we estimate that once placed in-service, the Minnesota ADMS system will cost approximately $1.9 million per year in O&M to pay for external software support and maintenance, hardware support, wide-area network costs and internal labor supporting the application and technical infrastructure. As discussed above, our contract with Schneider includes an ongoing agreement to provide support. We have also budgeted for both capital & O&M labor for the engineering and support expenses anticipated to maintain and operate the system.

6. *Summary and Current Forecast*

We provide below a snapshot of the capital and O&M costs associated with this ADMS initiative.

Table 1: Project Capital Expenditures Budget Summary (Dollars in Millions, on a MN basis)[9]

	Pre-2019	2019	2020	2021	2022	2023	2024	2025	2026	Total
Capital	$24.9	$10.7	$8.6	$5.4	$2.2	$2.6	$2.5	$4.1	$0.0	$61.0
O&M	$0.1	$1.1	$1.9	$2.7	$2.2	$2.2	$2.1	$4.3	$2.1	$18.7
TOTAL	$25.0	$11.8	$10.5	$8.1	$4.4	$4.8	$4.6	$8.4	$2.1	$79.7

As noted above, our current estimated capital cost for the Minnesota jurisdiction is $61.0 million which includes the labor, software, hardware, and GIS data collections efforts (for the Network Model Build). The net lower $8.1 million capital estimate is the result of the following changes, by major category.[10]

Labor – Our labor estimate has *increased* by $3.8 million, primarily due to:

- Schedule delivery delays encountered in all three Operating Company deployments.

[9] Please see Attachment 7B for the NSPM Total Company CWIP Expenditures for the ADMS project costs being requested in this TCR Petition.
[10] As discussed more below, not all of these costs are recovered through the TCR.

- Creation of additional training refresher materials due to COVID-19 halting in-person classroom training.
- Additional resources required to perform software testing, field device testing and implementation activities.
- Extension of key vendor partnership contracts to retain project team members for longer schedule duration and perform additional services.
- Key vendor contracts exercising contractual provisions to increase bill rates for cost-of-living adjustments.
- ADMS software scope expansion to provide additional functionality.

GIS Data Collection – Our estimate for the GIS asset data work *decreased* by $16.9 million due to a reduced field data collection scope.

Hardware – Our estimate for hardware *increased* by $5.0 million. This is primarily due to expansion of the scope in Minnesota to implement the ADMS system in two additional Distribution Control Centers, and higher costs associated with meeting new security standards and requirements.

B. Allocations to the NSPM Operating Company

As described in the Company's most recent electric rate case, O&M costs for preliminary planning related to capital software projects that benefit more than one operating company are allocated consistent with the Cost Assignment and Allocation Manual (CAAM) and the Service Agreement between Xcel Energy Services Inc. (XES) and NSPM.[11] As noted above, the ADMS project will be implemented across all operating companies of Xcel Energy.

When a new shared asset software system is in construction work in progress (CWIP), the accumulating charges will be collected under one work order for Xcel Energy Services. Since the Service Company will not own software, the appropriate percentage of ownership for each participating Operating Company is identified at the time of the initial development of the project. Each Company's share of the cost is then charged to that Company's CWIP monthly while under development, and ultimately classified to their own books. Each Operating Company will depreciate

[11] *See* the Direct Testimony of Company witness Mr. Ross L. Baumgarten in Docket No. E002/GR-21-630.

their respective share of the asset, and as such, no allocation is usually necessary. Management attention is taken to identify all beneficiaries at the beginning of the project so as not to allow later users a free service. In the case of ADMS, all Operating Companies and jurisdictions will benefit.

Investment in hardware for ADMS is being made in both PSCo and NSPM to support the system in all operating companies. There are primary and back-up servers located in data centers in both Minnesota and Colorado that will serve the NSP, PSCo, and SPS systems. Due to the flexible use of the various hardware components to support all the instances of ADMS, the Company determined that these investments would be purchased as network equipment and therefore charged out to all operating companies through our standard shared asset allocation process, similar to other data center network equipment. A carrying cost on this hardware investment is further allocated to the various operating companies. As a result of this allocation process, we do not believe it is practicable to recover the hardware costs of the ADMS through a rate rider. Therefore, we have shown the detailed hardware costs above for completeness in describing the project, but do not include these costs in the TCR revenue requirement. ADMS hardware costs will be included in a future rate case.

C. Service Life

ADMS components are not significantly different from existing capital asset classifications, and therefore they fall under existing Federal Energy Regulatory Commission (FERC) accounts for software and communications equipment. The depreciation rates for these asset categories are reviewed and approved annually, with the most recent approval in the Commission's March 24, 2021 Order in Docket No. E,G002/D-20-635. On July 29, 2021, the Company submitted its next annual depreciation filing, which is still pending in Docket No. E,G002/D-21-584.

The ADMS project consists of two asset categories: software and communications equipment. Software has a 5 year life. Electric FERC 397 Communications has a 10 to 15 year average service life, depending on sub classifications. The ADMS communications equipment is currently classified as having a 10 year average service life in its subaccount. Every five years, the Company performs a comprehensive depreciation study of FERC accounts. The next 5 year study will be filed with the Commission in 2022. At that time, the accounts will be reexamined, and if necessary, we would reset any depreciation lives. However, we do not anticipate separating the

ADMS components from the existing software and communications equipment accounts.

D. ADMS Costs in Base Rates

Approximately $8.2 million in capital additions related to the IT component of the ADMS software and GIS Network Model Build improvement were included in the 2018 MYRP revenue requirement. This cost is only a limited portion of the full ADMS system. To ensure we were not double-recovering our costs for these projects, in past TCR Rider filings we had reduced our revenue requirements by the portion included in base rates. For this TCR Rider petition, however, we have zeroed-out the base rate removal line starting January 2022. The ADMS project as a whole has not been placed in-service prior to the 2022 Test Year, and thus will continue to be collected in the TCR rider. This aligns with how other projects are being treated in regards to what will be requested to be moved to base rates versus remain in the TCR rider. As such the entirety of the the ADMS project was removed from the rate case to ensure there is no double recovery. The result of removing this offset is an increase in the 2022 revenue requirement in the TCR rider. See Attachments 8A and 8B for the details of these adjustments.

CONCLUSION

The ADMS is a foundational tool for grid modernization and more. It is a critical part – the “engine” – of the overall package of tools necessary to deliver reliability, energy efficiency measures, and to enable the integration of increasing quantities of DER without compromising reliability and power quality. We have taken reasonable and appropriate measures to implement and manage the ADMS initiative in a cost-effective manner that maximizes value for our customers.

Residential Time of Use (TOU) Pilot

INTRODUCTION

The Residential Time of Use (TOU) Pilot, *Flex Pricing,* provides customers with pricing specific to the time of day energy is used. The Pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods where the system is experiencing low load conditions. Price signals that shift load away from peak may reduce or avoid the need for system investments in fossil fuel plants that serve peak electric load.

The Pilot was developed partially in response to customer and stakeholder feedback about the benefits of alternative rate designs as developed in a prior regulatory proceeding. Through the Pilot, the Company is studying the impact of rigorously designed price signals with technology-enabled data on customer usage patterns for a subset of customers. The Company will share learnings about the effectiveness of these techniques to inform future consideration of a broader Time of Use rate deployment in Minnesota.

I. PILOT SELECTION

The Residential TOU Pilot was developed in consultation with stakeholders, and the Pilot's goals, design, implementation plans, and costs were thoroughly vetted by parties in Docket No. E002/M-17-775. In its Order dated August 7, 2018 in Docket Nos. E002/M-17-775 and E002/M-17-776, the Commission approved and certified the TOU Pilot.

II. IMPLEMENTATION

Customers selected for the Pilot include a subset of those served out of the Westgate substation (which includes portions of Eden Prairie, Chanhassen, and Minnetonka) and the Midtown substation (located in Minneapolis). We installed approximately 17,000 new meters on a sample population of residential customers in these areas. With the support of a third-party Measurement and Verification (M&V) expert, we have divided customers who received new meters into "treatment" and "control" groups. Customers selected for treatment were automatically enrolled onto new TOU rates and retain the ability to opt out of the Pilot at any time. Customers in the control group received new meters but experienced no change to their flat rates. The targeted areas will enable the Company to study the impact of the Pilot's features on a diverse group of customers, and to deploy the required technology within an efficient footprint.

The Company completed contract negotiations with the Advanced Meter Infrastructure (AMI) vendor at the end of 2017. In early 2018, we began designing, building, and testing of the IT system. In early 2019, the head-end system was completed. We implemented a multi-phase customer outreach strategy in early 2019. Field Area Network (FAN) communications were installed in the second half of 2019. Meters were installed in the pilot areas during the latter half of 2019 and early 2020. When the meters were all in place, we collected baseline data from customers prior to implementing new rates.

We initially expected to launch the Pilot for all participants in the first quarter of 2020, and we were planning for an April 1, 2020 launch. However, on March 18, 2020, the Company notified the Commission that due to the COVID-19 pandemic, the Company was postponing the start date. On September 10, 2020, the Company notified the Commission that the pilot would begin on November 1, 2020.

As required by the August 7, 2018 Order, the Company provides one-page "dashboard" monthly reports detailing enrollment, customer bill impacts, and energy usage data beginning in December 2020. The Company expects to file the required mid-point report in the first quarter of 2022 which will provide detailed metrics as outlined in the August 7, 2018 Order. A final report will be filed with the Commission after the Pilot concludes.

III. COSTS AND BENEFITS

1. *Capital Costs*

The estimated total TOU Pilot capital costs at the time of project certification in 2017 (Docket No. E002/M-17-776) are summarized in Table 1 below, and include costs for items such as the AMI meters, software licenses, head-end, and various integration and customer presentment costs. These costs were based on the expected implementation timeline.

At the time of the certification request, we assigned a portion of supporting FAN costs to the TOU Pilot, because it required earlier deployment of FAN infrastructure. The same FAN infrastructure will ultimately benefit all advanced grid projects –

including AMI. The FAN cost estimate presented in the certification docket included approximately $503,000 assigned to the TOU project and approximately $2.3 million assigned to the Fault Location, Isolation, and Service Restoration (FLISR) project, for which we were also seeking certification at the time.

Table 1: Total Estimated TOU Pilot Costs – Capital
State of Minnesota
(millions)

	2018	2019	2020	2021	2022	2023-2027	Total
TOU Pilot	$0.5	$6.2	$0.6	$0.3	$0.0	$0.0	$7.6
FAN*	$2.5	$0.5	$0.0	$0.0	$0.0	$0.0	$3.0
Total	**$3.0**	**$6.7**	**$0.6**	**$0.3**	**$0.0**	**$0.0**	**$10.6**

Table 2 below provides more detailed capital costs for the TOU Pilot as initially presented in Docket No. E002/M-17-775, where we requested Commission approval of the project concurrently with filing the certification docket. We also provide a comparison of the initial estimated costs to our current forecasted costs by line item.

Table 2: TOU Pilot Total Capital Costs

Capital Cost Item	2017 Estimated	Current Forecast (Excluding AFUDC)
Metering	$3,858,191	$4,642,848
AMI Software Licenses	$252,000	$59,275
Head End	$2,382,693	$5,806,649*
Customer Resource System (CRS)	$922,740	
Customer Data Presentment	$141,375	
SUBTOTAL:	**$7,556,999**	**$10,508,722**
FAN - Mesh	$503,177	$1,041,645
TOTAL:	**$8,060,176**	**$11,550,417**

**Functionality delivered within PSCO Shared Asset, carrying costs allocated to NSPM based on AMI meter count. Discussed in more detail below in Section 3.*

We experienced some cost increases after submitting our initial certification request related to installation, vendor selection, and meter costs as a result of change in AMI procurement strategy. We did, however, experience some cost savings related to the AMI software licenses.

2. O&M

The estimated total TOU Pilot O&M costs at the time of project certification in 2017 (Docket No. E002/M-17-776) are summarized in Table 3 below, and include costs for items such as AMI meter installation support, consulting for program development and measurement and verification (M&V), and marketing communications. These costs were based on the expected implementation timeline.

Table 3: Total Estimated TOU Pilot Costs – O&M
State of Minnesota
(millions)

	2018	2019	2020	2021	2022	2023-2027	Total
TOU Pilot	$0.4	$1.1	$0.5	$0.5	$0.4	$0.3	$3.2
FAN	$0.1	$0.0	$0.0	$0.0	$0.0	$0.0	$0.1
Total	**$0.5**	**$1.1**	**$0.5**	**$0.5**	**$0.4**	**$0.3**	**$3.3**

As discussed below in Section 3, we are not requesting cost recovery of the TOU Pilot through the rider until the 2022 test year, and so a majority of the project O&M costs will not be recovered through the rider.

3. Rider Cost Treatment

a. Cost Allocation

Our initial filing showed the TOU Pilot head-end costs as capital costs. However, investment in hardware and software for AMI and FAN is currently being made in our Public Service Company of Colorado (PSCo) Operating Company to support the system in all operating companies. Due to the flexible use of the various hardware components to support AMI and FAN, the Company determined the AMI head-end system, one of the major expenses in the TOU Pilot budget, will be a shared asset owned by PSCo that will serve the Northern States Power Minnesota (NSPM), Northern States Power Wisconsin (NSPW), PSCo, and Southwestern Public Service Company (SPS) systems. Shared assets are those assets or facilities that are owned by one of the Xcel Energy Operating Companies and used by an Xcel Energy affiliate (e.g., NSPM). This is different from a common or allocated asset, such as the Advanced Distribution Management System (ADMS) software, which is developed for multiple companies with the costs allocated accordingly from the outset. PSCo will charge out to the Operating Companies through our standard shared asset allocation process, similar to our 414 Nicollet Headquarters building. A carrying cost on this investment is further allocated to the various Operating Companies. On a monthly basis, the shared asset costs are allocated from PSCo based on actual meter deployments in each Operating Company. These costs appear as O&M costs in the rider. See Attachment 13 for the project O&M costs.

We note that NSPM carries a larger share of the head-end cost allocation in the early years as meters were deployed in Minnesota earlier than in our PSCo service territory. This balance will shift as more meters are installed in Colorado. Thus the current forecast for this line item in Table 2 is greater than the initial forecast.

We similarly allocate costs related to CRS and Customer Data Presentment, as noted in Table 2 above. Those costs are also included in the O&M recovery line item Attachment 13.

The TOU Pilot is enabled by both FAN and AMI technology. Additional work needed to enable the TOU Pilot was incorporated into the planned mass meter deployment work. As a result of the timing of costs allocated to the TOU Pilot through the shared asset allocation methodology described above, the expected costs related to the head end, CRS, and Customer Data Presentment in Table 2 are higher than the original forecast. However, because the required functionality was built into the design and build of the enterprise assets, the Company was able to avoid costly duplication of efforts, including performance and scalability testing, which would have been incurred more than once had the Company only implemented specific jurisdiction requirements at the time. This would have ultimately resulted in higher costs to produce the final enterprise assets and increased the overall cost of the TOU Pilot and the mass meter deployment as a result of incurring those duplicate costs.

b. Costs Included in TCR Rider Recovery

Though certified in 2018, we have not included costs related to the TOU Pilot prior to 2022 in this TCR Rider request because a portion of those costs were included in our MYRP filed in Docket No. E002/GR-15-826. We removed TOU Distribution and Business Systems costs from the recently filed MYRP in Docket No. E002/GR-21-630 consistent with the removal of the other Distribution-Grid Modernization projects, beginning with the 2022 test year.

Tables 4 and 5 below show the costs that are included in the TCR Rider at this time.

Table 4: Capital TOU Pilot Costs Included in TCR Rider*

	Pre-Eligible AFUDC	2018	2019	2020	2021	2022	2023	Total
Metering	$23,952	$57,589	$4,204,973	$230,903	$(116)			$4,517,301
FAN–Mesh	$63,002		$903,203	$182,071	$(722)			$1,147,554
AMI Software Licenses	$1,072		$30,958	$25,787				$57,817
TOTAL	$88,026	$57,589	$5,139,134	$438,761	$(838)			$5,722,672

** This table includes internal labor and the costs are summarized in Attachment 7B. Attachment 7A shows the capital costs being included for recovery excluding internal labor.*

Table 5: O&M TOU Pilot Costs Included in TCR Rider*

	2018	2019	2020	2021	2022	2023	Total
Head End CRS Customer Data Presentment	$0	$0	$0	$0	$101,245	$91,922	$193,167

**These cost types are not allocated individually and thus an aggregate amount is shown.*

We note that consulting for program development, M&V, and marketing communications are Customer Care functions not generally associated with AGIS projects and were therefore included in the 2022 MYRP Customer Care budget. We have not included those O&M costs in the TCR Rider.

Since we are not requesting cost recovery of the TOU Pilot through the TCR Rider until the 2022 test year, we will only recover O&M costs associated with the project beginning in 2022, although we did incur O&M costs related to the project in prior years.

4. *Benefits*

The Pilot is focused on providing benefits contemplated under the Grid Modernization statute. Namely, the Pilot will increase conservation opportunities for customers, as it deploys advanced metering capabilities to facilitate communication between the utility and customer participants in service of on-peak energy efficiency and load-shifting. It also enables demand response activities through increased communication capabilities, customer information and education, and targeted price signals. In addition to energy conservation and communication benefits, the features of the Pilot also modernize the grid by enhancing reliability. The AMI technology selected for this Pilot acts as a voltage input, providing data to the ADMS to improve grid operations. It also includes outage reporting functionality that enhances outage response capability and improves reliability.

The Pilot will also generate beneficial learnings on the ability of residential customers to respond to price signals and tailored educational messages by engaging in energy efficiency and shifting energy usage to non-peak periods. By limiting the TOU rate and technology implementation to a subset of customers, the Company will measure and verify key assumptions about the project in advance of a wider rollout.

CONCLUSION

In summary, the TOU Pilot provides the Company the opportunity to study the impact of price signals with technology-enabled data on customer usage patterns for a subset of customers and then share learnings about the effectiveness of these techniques to inform future consideration of a broader Time of Use rate deployment. A detailed mid-point report on the Pilot is forthcoming and will provide more information about the progress of the Pilot thus far.

AMI AND FAN PROJECT DETAILS

I. INTRODUCTION

The Company has recently undertaken significant work to modernize the distribution system. This begins with foundational advanced grid initiatives that both provide immediate benefits and new customer offerings while also enabling future systems and customer value. Our grid modernization efforts will ensure the electric distribution grid is well-positioned to meet future grid and customer needs while maintaining reliability, safety and security.

These initiatives started with our Advanced Distribution Management System (ADMS), which the Commission certified in 2016 and we are in-servicing in Minnesota in 2021. The ADMS is foundational to advanced grid capabilities that will, among other things, provide the visibility and control necessary for enhanced planning and significant Distributed Energy Resources (DER) integration. In 2018, the Commission certified a Residential Time Of Use (TOU) pilot (Flex Pricing) that began in 2020 and will conclude in 2022. This Pilot involves the installation of approximately 17,500 Advanced Metering Infrastructure (AMI) meters in two communities in the Twin Cities metropolitan area and is studying customer responses to price signals, to explore and identify effective customer engagement strategies, and to understand customer impacts by sector.[1]

And most recently, in our 2019 Integrated Distribution Plan (IDP) and Grid Modernization Report, the Commission certified a comprehensive Advanced Metering Infrastructure (AMI) and a Field Area Network (FAN) initiative, which would deploy new meters to all of our Minnesota customers and a two-way communications network across our Minnesota service area.[2] AMI is an integrated system of advanced meters, communication networks, and data processing and management systems that is capable of secure two-way communication between Xcel Energy's business and operational data systems and customer meters. FAN is a secure two-way communication network that provides wireless communications across Xcel Energy's service area – to, from, and among, field devices and our information systems. In support of cost recovery for these initiatives, below we discuss the need for AMI and FAN, the process for selecting the technologies and

[1] This pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions.
[2] ORDER ACCEPTING INTEGRATED DISTRIBUTION PLAN, MODIFYING REPORTING REQUIREMENTS, AND CERTIFYING CERTAIN GRID MODERNIZATION PROJECTS, Docket No. E002/M-19-666.

vendors, the customer benefits, and other information that supports these initiatives and that complies with the Commission's requirements for cost recovery of Advanced Grid Intelligence and Security (AGIS) investments.

in summary, AMI and FAN are critical foundational elements of our grid modernization strategy. AMI is the Company's new metering solution – replacing our legacy Automated Meter Reading (AMR) system, which is being phased-out by our service provider – and will provide information that will interact with many of our other planned and future grid modernization components. FAN is the communication network that will enable secure and efficient two-way communication of information and data between the new AMI meters at customers' homes and businesses and other future field devices and the Company's backoffice systems. The system visibility and data delivered by AMI and FAN will provide customer benefits in reliability as well as the ability for remote connection, and greater customer offerings for rates, programs, and services. AMI and FAN will also enhance the Company's planning and operational capabilities by giving us access to timely, accurate and consistent data. From this data, we will provide enhanced information directly to customers, allowing them to make better informed decisions about their energy usage. The volume and scope of data from the AMI meters delivered over the FAN is several orders of magnitude greater than our legacy metering infrastructure, allowing many business processes and services supporting our customers to be more timely, accurate and consistent. We are excited to begin this step change in advanced technology and the benefits it will bring our customers and our operations.

In the following sections, we discuss the need for AMI and FAN, customer benefits, project costs, actions we have taken to minimize costs for customers, project implementation, and the metrics we are committing to reporting.

II. NEED FOR AMI AND FAN

In this Section, we discuss the Company's need for investments in AMI and FAN. This is driven in the immediate-term by the Company's current AMR meters reaching the end of their lives. But, as discussed below, the decision to transition to AMI as a replacement is based on the value this technology will provide to our customers and our ability to operate the grid.

Drivers of our grid modernization strategy include:

- Our strategic priorities to lead the clean energy transition, enhance the customer experience, and keep bills affordable;

- Our desire to meet the growing needs and expectations of our customers;
- Our current distribution system needs; and
- Commission policy and direction, and stakeholder input relative to customer offerings, performance, and technological capabilities of the grid.

Over the last several years, we have experienced a variety of converging needs and opportunities related to distribution grid modernization – some driven by internal system needs, others by industry direction, and others by customers and other stakeholder considerations. Now is the right time to begin a more significant advancement of the grid with AMI and FAN.

We are working every day to lead the transition to a clean energy future, enhance our customers' experience with their utility, and keep bills low. Our grid advancement strategy is intended to support each of these strategic objectives. We believe our customers can be partners in a more environmentally sound future, especially if they are empowered with better information and data to manage their energy usage and make conservation-friendly choices. AMI and FAN are critical to these efforts. Likewise, DER are also a key to this clean energy future, and two-way communications on the distribution grid, down to the meter level, are necessary to accommodate increased levels of DER on the system.

Influenced by other services, customers have come to expect more from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use. Customers are demanding more optionality and increasing levels of service from all their service providers – including their provider of electric service. Customers also expect greater functionality and interaction in how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, (Electric Vehicle (EV) chargers, smart home devices, and even smart phones and energy-related digital applications, are evolving at a fast rate. Our grid modernization initiative and specifically our plans around AMI and FAN is intended to create better interfaces with customers, provide them with better information and more choices, and thus improve their overall experience. Coupled with efforts to improve the digital platforms through which we interact with customers, improved energy management, control, conservation, and bill management are all available with a more interactive, advanced distribution system. And it goes without saying that continually enhancing our customers' reliability experience is at the core of quality electric service.

Customers want access to actionable information, more choice and greater control of their energy use – and they expect a smarter, simpler and more seamless experience. Enhancing the customer experience is critically important, and is one of our three strategic priorities, along with leading the clean energy transition and keeping bills low. We plan to integrate modern customer experience strategies with advanced grid platforms and technologies to enable intelligent grid operations, smarter networks and meters, and optimized products and services for our customers. Implementation of AMI and FAN offers our customers opportunities to better control and manage their monthly bills by providing more timely and granular energy usage data and enabling advanced rate design. In addition to transforming the customer experience, these foundational and core investments will allow us to advance our technical capabilities to deliver reliable, safe, and resilient energy that customers value. And, the costs of this initiative will be spread over the implementation period, which reasonably manages the cost impact for our customers.

Finally, we must act to replace our current AMR service to ensure we continue to provide our customers with timely accurate bills; as we have noted, our current vendor is sun-setting its AMR technology in the mid-2020s. While our legacy system has provided value to customers for many years through efficient meter reading, we have an opportunity now to seize AMI technologies that are becoming available to maximize value for our customers. As we chose the specific AMI and FAN technology, we will deploy to replace AMR, we focused on three goals: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities, which we discuss below.

A. AMR Technology Reaching End of Life

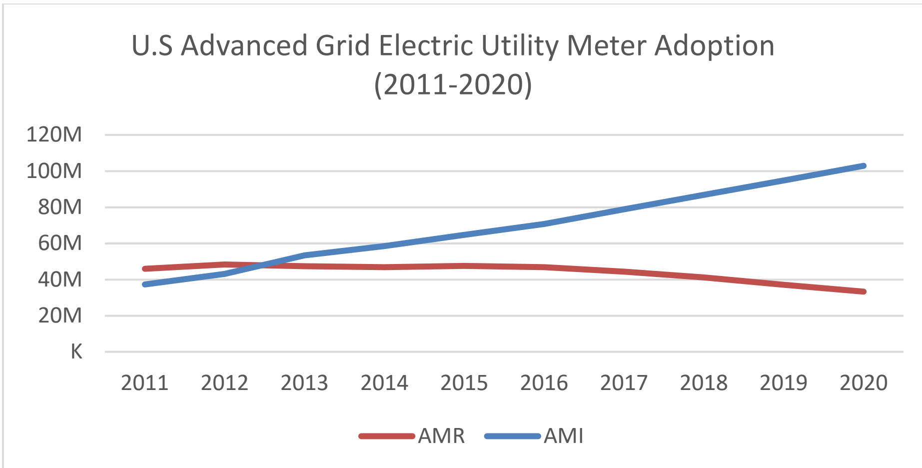
Our current AMR system has been in place since the mid-1990s. Meter readings are collected and provided to the Company via a proprietary network by Landis+Gyr (Cellnet), our current meter reading services vendor. In general, it is a fixed network, one-way communication system with limited functionality that is primarily related to meter reading for billing purposes. As discussed in our 2019 certification request for AMI and FAN in Docket No. E002/M-19-666, our current AMR technology is nearing end of life, and Cellnet will no longer manufacture replacement parts for this system after 2022. Given that the Cellnet system is a proprietary system, replacement parts are not commercially available from other vendors. As a result, as these meters age and require repair, we will not be able to purchase the necessary replacement components after 2022.

In fact, we are the last Cellnet customer still using this technology and our current contract for meter reading service and support expires at the end of 2025.[3] We have maximized the value of our legacy AMR system, which provided efficient meter reading services for nearly 30 years. We need to invest in new meters in order to continue to provide our customers with timely accurate bills. AMI is the right technology. AMR technology is a dated technology and much of the industry has or is moving to AMI meters. Further, the progressively complex needs of our customers and the distribution system require movement to technology that can accommodate those needs.

The expiration of our Cellnet contract comes at a fitting time given the current state of the AMI market and its technology. AMI has advanced to the point where it is an established meter technology that has widespread adoption. Installation of AMI meters has doubled since 2010 and since the end of 2016 nearly half of all U.S. electric customer accounts have AMI meters. According to the United States Energy Information Administration (EIA), AMI adoption surpassed AMR in 2012, and the gap has widened as AMR deployment has remained flat. The EIA's most recent Form EIA-861 indicates that, by the end of 2019, approximately 60 percent of deployed meters in the United States were AMI. The number of AMI and AMR meters deployed between the years 2010 and 2019 increased by approximately 609 million and 454 million respectively. In comparison, deployment of non-AMR meters was significantly lower at approximately 228 million. The trend is clearly to deploy AMI – as the proportion of both AMR and non-AMR in relation to the total meters deployed shrank over this period, while AMI expands significantly as shown in Figure 1 below.

[3] While we could conceivably continue to maintain our existing AMR meters, many of these meters were installed in the 1990s and are between 20 to 30 years old. Due to their age, we expect that these meters may begin to experience mechanical issues in the coming years and we will not be able to get meter replacement parts after the end of 2022.

Figure 1: U.S. Meter Deployment Snapshot



Source: EIA Electric Power Annual Electricity Report (2020 Data) – Table 10.05 Advanced Metering Count by Technology Type, 2011 through 2020. [*https://www.eia.gov/electricity/annual/*](https://www.eia.gov/electricity/annual/)

These numbers indicate a continuing industry trend of deploying AMI technology.

Not only is AMI the right technology for the future – it is the right replacement for our legacy system that is at the end of its life. As we discuss below, in addition to opening up opportunities to provide increased and enhanced customer offerings, we will gain valuable data enabled by the AMI meters and the two-way FAN that will help us improve our operations, costs, and the service we provide to customers.

B. Transformed Customer Experience

Like we did in our 2019 certification request for AMI and FAN, we outlined our customer strategy and roadmap for our grid modernization investments in our November 1, 2021 IDP in Docket No. E002/M-21-694. . We provide a summary of that here, and a link to that document for additional details.[4]

In summary, we have developed a customer strategy that aims to transform the customer experience by implementing capabilities, technologies, and program management strategies to enable the customer experience that our customers now expect. It is focused on shifting the customer experience dynamic to one where little

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[4] *See* Appendix B2: Customer Strategy and Roadmap at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={2018DC7C-0000-C41B-992F-7ED95D99A9EE}&documentTitle=202111-179347-01

action is required from customers around their basic service and where we offer personalized "packages" that customers can select from to meet their specific needs. These packages may include options such as demand-side management, renewable energy, rate design, and non-energy services. Additionally, in the cost benefit analysis described above, there are quantifiable benefits such as the flexible load benefits that provide savings to all customers, both residential and C&I.

Rather than simply evolving from our current state, we are revisiting our entire customer experience. Today, customers expect that we *know them* and take a personalized approach to their relationship with us; they expect that we keep them *informed* and use our expertise to *advise* them about what to do and then *empower* them to take those actions; and finally, that we *deliver seamless* experiences for them reducing the burden on them to take action.

Figure 2: Customer Experience Priorities

In order to meet these expectations, we are taking time to understand the customer's journey and experience in our program design and execution. This process starts with a commitment to understanding customers' preferences, considerations, and motivations regarding the benefits and value of an advanced grid investment. We conduct robust customer research and continually update that research to ensure we are reactive to our customers' perceptions. It also requires the Company to improve the skills and competencies needed to continuously evolve and iterate our programs more quickly and leverage technology to make interactions more streamlined and enjoyable.

The initial investments to begin meeting our customers' growing expectations with respect to the distribution system are already underway. Our implementation of the ADMS in 2021 is preparing the grid for increasing levels of DER. It is also paving the way for further grid advancement with AMI and our ability to leverage the underlying and necessary FAN to improve customers' reliability experience through Fault Location, Isolation, and Service Restoration (FLISR) and more. Customers will have access to granular energy usage data from our AMI meters through a customer portal, which we expect to pair with informed insights and helpful tips on how to change their behavior to save energy. As we discuss below, the Distribution Intelligence (DI) platform included with the AMI meters will be able to provide customers with even deeper insights and greater benefits, particularly as we begin the process of updating the meters with new software applications, much like customers can currently update their mobile devices with applications.[5]

The AMI and FAN technologies combine to transform the customer experience to provide greater visibility and insight into customer energy consumption and behavior. We will use this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications.

We will offer options that give customers greater convenience and control to save money, provide access to rates and billing options that suit their budgets and lifestyles, and provide more personalized and actionable communications. As our system more efficiently manages energy flows with these and future grid modernization technologies, we can save customers money by reducing line losses and conserving energy. AMI meters will be the platform that enables new products and services and contributes to improved reliability for our customers. Our customers will have more information to make more effective decisions on their energy use.

We will know more about our customers and our grid – and we will use that information to make more effective recommendations and decisions and continually use new information to develop new solutions. This will serve to help keep our bills low, as customers save money through both their actions and ours. It will also help ensure that our transition to a carbon-free system occurs efficiently – and harnesses

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[5] *Id.* We are seeking certification of DI in our 2021 IDP and discuss it in detail in IDP Appendix G: Distributed Intelligence Certification Request.

the vast potential of all energy resources, from utility-scale to local distributed generation.

C. Improved Core Operations and Capabilities

Our AMI and FAN investments, along with other grid modernization investments, will more efficiently and effectively deliver the safe and reliable electricity that our customers expect. Specifically, with AMI and FAN, we will have the capability to communicate two ways with our meters and other grid devices, sending and receiving information over a secure and reliable network in near-real time.

Our current service is reliable; however, we need to continue to invest in new technologies to maintain performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources and as industry standards continue to improve. AMI and FAN are an integral part of an overall set of advanced grid investments that provide the platform and capabilities to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics and automation.

With AMI and FAN, our systems will more efficiently and effectively restore power when outages do occur using automation without the need for human intervention. Our systems will be better at identifying where the outage is and what caused it – benefiting customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

D. Facilitation of Future Capabilities

The backbone of our investments will also support new developments in advanced products and services. We will do this in the short-term by supporting the display of more frequent energy usage data through our planned customer portal, and over the long-term, allowing for the implementation of more advanced pricing programs. We are designing our grid modernization plan for interoperability, which enables a cost-effective approach to technology investments and means we can extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion; this unlocks new offerings and benefits that build on one another. Similarly, we have planned our advanced grid investments in a building block approach, starting with the foundational systems, in alignment with industry standards and frameworks. By doing so, we sequence the investments to yield the greatest near- and long-term customer value, while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

In planning our advanced grid initiative, we have considered the long-term potential of our ability to meet our obligations to serve our customers' expectations and needs – ensuring we extract cost-effective value from our investments and remain nimble enough to react to a dynamically changing landscape. The principles we applied to our advanced grid planning include the ability to remotely update hardware and software, security, reliability and resilience, and flexible, standards-based service components. We are planning our grid advancement with the future in mind, and to provide both immediate and increasing value for our customers over the long-term.

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative and our customer strategy to address them and harness value for our customers. In addition to transforming the customer experience, these foundational investments will allow us to advance our technical capabilities to deliver reliable, safe, and resilient energy that customers value. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

Now is the time to modernize the interface where we connect directly with our customers – the distribution system. Technologies have evolved and matured; our peers have successfully implemented these technologies; and, the industry landscape is evolving. We must ensure our system has the necessary capabilities to meet our customers' expectations and needs – and, the flexibility to adapt to an uncertain future.

We are taking a measured and thoughtful approach to advancing the grid to ensure our customers receive the greatest value, the fundamentals of our distribution business remain sound, and we maintain the flexibility needed as technology and our customers' expectations continue to evolve.

III. ADVANCED METERING INFRASTRUCTURE

In this section, we describe the AMI equipment and its functionalities and capabilities. We start with an overview of AMI in the industry, then discuss the AMI equipment itself, and finally our process for selecting specific meter technology.

A. AMI Equipment

Xcel Energy selected the Itron RIVA 4.2 meter, shown in the below Figure, for its mass implementation of AMI.

Figure 3: Itron RIVA 4.2 Meter

The primary components of these meters are:

- The meter and its energy measurement capabilities,
- An embedded two-way radio frequency communication module,
- Embedded Distributed Intelligence capabilities, and
- An internal service switch.

The AMI system also relies on a "head-end" application, which is the operating system that is used to send data requests and commands to an AMI meter and receive data from the meter. This enables the transmission of data and commands between the AMI meters and the Company.

1. *Metering Functionality*

The primary purpose of the AMI meters is the same as our existing meters – to measure the amount of electricity used by our customers for billing purposes.

However, the AMI meters have additional capabilities. For example, they can be remotely configured to measure bi-directional and/or time-of-use (TOU) energy consumption in kilowatt hours (kWh) and demand in kilowatts (kW).[6] Today, to achieve bi-directional energy measurement, we generally must install two meters – one to measure energy delivered by the Company to the customer, and one to measure the net energy delivered by the customer to the Company's system. AMI enables the main meter that measures total energy delivered to the customer and net energy delivered by the customer to the company system, to be remotely reconfigured to measure bi-directional energy without having to replace the AMI meter. For TOU rates, today we can program our existing meters to measure energy usage for specific time intervals – but that programming must be physically done at each meter, rather than remotely programmed and pushed out to the individual meters over a communications network, which will allow for greater participation in TOU rates and calibration of such rates over time.

Energy consumption data for billing purposes can be recorded by AMI meters in intervals as short as five minutes, and in most cases will be configured for 15 minute intervals. The AMI meters also provide granular data regarding voltage, power quality, and outages. While capable of transmitting at shorter intervals as needed, we anticipate the AMI meters will typically collect and transmit data to the Company a minimum of six times per day or every four hours. However, there are several instances when the meters will communicate more often than every four hours. Some examples of this more frequent communication include:

- Individual meters can be read on an on-request basis. For example, a Customer Care employee may request and collect the meter data while on the phone assisting a customer.
- Through the MyAccount internet portal or a smartphone application, a customer could request an on-demand meter reading. This request will provide a customer with near real-time energy information.
- AMI meters will transmit data when an event occurs such as a power outage, power restoration, power quality event, or a diagnostic event. The length of time between the data transmission and the event depends on the type of the event.

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[6] An advanced meter that is configured for bi-directional energy measurement measures energy provided by the Company to the customer, and also measures net energy provided from customers (i.e., customers with solar panels or DER) to the Company.

- AMI meters selected along the distribution feeders to provide data to ADMS will be configured for five-minute interval data, and will transmit data to the AMI head-end application every five minutes to make that information available to ADMS.[7]

In addition to the previously discussed ability to measure, store, and transmit interval meter data, AMI meters also have additional capabilities including the following:

- Measure and transmit voltage, current, and power quality data;
- Detect and transmit meter power outage and restoration events;
- Detect and report meter tampering events;
- Perform and transmit meter diagnostics pertaining to the correct functioning of the meter and communications module;
- Support customer-facing energy conservation technologies (i.e., smart thermostats);
- Support Distributed Intelligence; and
- Support remote connect/disconnect functions for customers taking single-phase service (generally, residential and some small business customers).

2. Additional Metering Capabilities

As we have noted, the AMI meters have three additional primary capabilities, which we outline below.

a. Two-Way Communications

The AMI meters have two main boards and a two-way radio frequency (RF) communication radio (Wi-SUN or mesh) that is an important component of the FAN. The first board contains an ARM cortex microprocessor with 256 megabytes (MB) of RAM, 512 MB of flush, and 2 gigabytes (GB) of extended flush memory with a linux computer, Wi-Fi radio, and a Wireless Smart Utility Network (Wi-SUN) compliant 802.15.4g standards-based mesh radio. The second board contains the metrology. The Wi-SUN radio supports speeds up to 600 kilobits per second that provide two-way networking capability. The Wi-SUN radio retrieves meter data that is stored within the meter as prescribed by IEC 62056 – DLMS/COSEM

[7] These representative meters are commonly referred to as "bellweather meters."

standards. The RF communications in the meters may also act as a repeater for other mesh network devices such as those used for FLISR, enabling two-way communication between the meters and the mesh network.

This function has the benefit of increasing communication resilience between AMI meters and the head-end application. For example, if the communication signal is weak between an AMI meter and the access point device, the meter may have a stronger communication path to the access point by having another meter (or several meters), act as a repeater to facilitate the communications such as:

- Transmitting measurements, alarms, and events performed by the meter to the head-end application,
- Receiving commands from the head-end application to send specific meter measurements, alarms, and events, configure the meter to measure specific sets of energy parameters or time-of-use intervals and data recording intervals,
- Remotely performing meter firmware upgrades, and/or
- Receiving commands from the head-end application to open or close the internal service switch and communicate its status.

The primary purpose of the two-way radio is capturing and transmitting customer billing data and service quality data from the AMI meter to the Company. However, there is a second Wi-Fi compatible radio transmitter within the meter that, *if a customer chooses*, can be configured to communicate with their Home Wi-Fi/Home Area Network (HAN) and capable in-home appliances and devices.

A HAN is a network contained within a customer's home or business that connects a customer's HAN-capable devices together. A HAN device can be as simple as an in-home energy display, or devices such as thermostats, home security systems, and smart appliances. If the customer chooses to connect their HAN with the AMI meter installed at their home or business, these devices can communicate with each other to support energy management and efficiency functions.

b. Distributed Intelligence and the Grid Edge

Our AMI meters have an Internet of Things (IoT)-based technology platform that is essentially a computer at customers' homes and businesses. This is also sometimes called Distributed Intelligence (DI) or "grid edge computing" – referring to the distribution of computing power, analytics, decisions, and action away from a central control point and closer to localized devices or platforms where it is needed. This built-in "computer" uses a Linux-based operating system that provides the capability to solve challenges on the electric power grid through the use of edge computing contained in a meter in conjunction with a backend computing and management infrastructure. We requested certification of the foundational capabilities necessary to use DI and the deployment of our first wave of uses for DI as part of our 2021 IDP. We intend to use this platform to develop a DI ecosystem, which consists of new meter data as well as "apps" running directly on the meter (like how applications are installed on smartphones) to facilitate various grid operations, grid notifications, and customer services.[8]

These applications may be customer-facing, meaning the customer directly interacts with them, or grid-facing, meaning the Company interacts with the applications. The localized processing is beneficial to customers and the Company, because it is not necessary for data to traverse long distances over communications networks to be processed and provide informational value to customers or the Company; it improves computational speed and efficiency, and is capable of providing near real-time information for customers to manage their energy usage and the Company to manage the grid more efficiently. DI in advanced meters and other leading-edge devices enables a broad array of new uses that will fundamentally transform how customers will use energy in their homes and businesses, as well as how we will be able to optimize our grid modernization investments.

The DI capabilities of the RIVA 4.2 meter allow it to be updated without needing to upgrade or replace hardware inside the meter. Moreover, applications can be updated, or new applications developed, which allows for the capabilities of the meter to expand and develop without the cost of physical repair or replacement. The DI capabilities also allow the AMI meter to run multiple applications at the same time without the need for instructions from the Company's back-office applications or control room. This is beneficial because it allows the AMI meters to communicate directly with each other regarding issues – analyzing and solving them directly, as opposed to communicating the issues to a back-office system and waiting for instructions to solve the problem. We are on the leading edge in the nation in deploying DI for AMI meters. As a leader in this space, we are working directly with

[8] To be clear, however, no DI application can be implemented solely using software on the meter alone. Rather, any DI application running on the meter must also have associated software running on the Company's backend system ensuring that the DI application can perform its portion of the overall solution or service for which it is intended.

Itron to design, develop, and implement new applications. Itron is already building several applications that can be enabled on the meter. The potential use cases include:

- Improved security and awareness,
- Energy usage control and savings,
- Greater insight into customer energy data,
- Better controls to manage and integrate systems, and
- Identification and notification for operational issues

While the specific use case for DI capabilities will depend on the applications employed, an example of these capabilities is managing demand during peak times to avoid transformer overloads. During a hot summer afternoon when energy use is rising due to air conditioning use, the AMI meters at each customer location could analyze this data in real-time. These meters could then share their individual data with the other meters served by a common distribution transformer, calculating and comparing the total load to the capacity of the transformer. The DI-equipped meters could discern when the transformer is approaching overload conditions and determine the most appropriate course of action, such as reporting, alarming, modulating, or possibly shutting off controllable loads to keep the transformer below its rated capacity. The same concept could help with the integration of EVs, as well. Finally, a transformer's capacity may be challenged by additional Photovoltaic (PV) penetration, as more of our distribution transformers begin to see their peak not from load, but from PV generation in the afternoon when solar production is strong, but loads are low.

c. Remote Internal Switching

The Itron RIVA 4.2 meters have an internal service switch that can remotely connect or disconnect power to residential or small commercial customers' electric service upon command from the AMI head-end data application. Once fully implemented, we expect our use of this capability will drastically reduce the truck rolls and field work that are now necessary to perform these activities.

We intend to take a phased approach to leveraging this capability. In the initial phase, we plan to use the remote switch to disable service after a tenant moves out of a premise, and reenable service upon initiation by the new tenant. This will reduce unbillable use, or what is sometimes called "unknown user," and reduce billing rework that is necessary when new tenants imitate their service retroactively. We may also use the remote switch to disconnect service in the field for credit/non-payment purposes, using a handheld device. This will allow us to use the remote switch to reconnect service more quickly once customers resolve the credit issue. The next phase will require revisions to our existing tariff and a variance to the Commission's Rules that today requires a field visit to collect payment prior to *disconnection* of service for residential or small commercial customers. If the Commission grants approval of a variance to those requirements, we would be able to avoid truck rolls and field visits for *both* disconnection and reconnection – resulting in cost and operational efficiencies, and more quickly restoring electric service to customers after they have been disconnected for non-payment.[9]

In the initial phase where we are employing the remote reconnection capabilities, our field collectors will use the remote disconnection capability through an iOS application on an iPad to disconnect service in conjunction with a field visit to the premise to collect payment in accordance with the Commission's Rules and our Tariff. By performing the disconnect in this manner, the Company will be able to remotely reconnect service upon receiving proper payment or establishment of a proper payment arrangement – facilitating a faster reconnection than if a field visit were necessary to reconnect.

3. Expected Service Life and Accounting Life

We discuss the service lives of the AMI and FAN equipment in our July 31, 2020 Transmission, Distribution, Generation Petition as approved in Docket No. E,G002/D-20-635. Today, our legacy meters fall into Federal Energy Regulatory Commission (FERC) Account 370 with a 15-year approved average service life (ASL) with a negative five percent net salvage. For the new AMI meters, we have created a new subaccount under FERC Account 370. As we note in that filing, the manufacturer of the AMI meters generally states that its assets will survive 20 years. Consistent with this guidance, we requested, and received Commission approval of, a 20-year ASL (equating to a 5.00 percent initial depreciation rate). Additionally, we expect that the small cost to remove the meter would be offset by any salvage on the meter at retirement. Therefore, our petition requested, and received approval of, a zero percent net salvage. For the FAN, we have a new subaccount under FERC Account 397 Communication Equipment. The FAN provides benefits to all AGIS and distribution grid modernization projects, but is

[9] We previewed this phased approach in a December 2020 Workshop and our September 2021 IDP Stakeholder Workshop and are currently soliciting informal feedback from stakeholders to inform the petition that we intend to submit in the first half of 2022 that seeks approval of the necessary variances.

designed and built according to the needs of various specific components, and each has different communication network requirements. Our petition proposed, and received approval of, a 20-year ASL with a zero net salvage percent. This equates to a 5.00 percent initial depreciation rate.

With respect to our existing electric meters, as they are removed and replaced with the new AMI meters, the legacy meters will be retired. As also discussed in the Direct Testimony of Company witness Mr. Mark P. Moeller in our MYRP filed October 25, 2021 in Docket No. E002/GR-20-630, we estimate the remaining unrecovered net book value of the legacy meters at approximately $28 million on December 31, 2024 – the expected end point for AMI meter deployment. While the deployment is ongoing, the legacy meters will continue to depreciate. As part of our ongoing MYRP, we propose that any remaining book value at the time AMI meter deployment is complete will be transferred to a regulatory asset and deferred for recovery as part of the Company's next rate case.

B. Meter Selection and Alternatives Considered

In this section, we outline our planning and procurement process, which involved several Requests for Proposals (RFPs) and a rigorous evaluation process.

1. Develop Business Requirements

Starting in 2015, on an enterprise-wide basis, the Company initiated a systematic approach for selecting an AMI software and legacy system integrations vendor. The Company ultimately awarded contracts (resulting from RFP processes) for a vendor to supply the software and mesh communications solution for AMI. The Company set forth the following requirements for an AMI solution vendor:

- Leading the design of the overall system and components.
- Procurement and installation of all hardware components that will run the software.
- Procurement of the software.
- Configuration of the software and hardware.
- Designing, procuring and installation of the necessary additional hardware and software referred to as the "head-end" application that reads the meters and other field devices in the AMI solution and monitors and manages the network and attached devices. System performance and capacity must support the

expansion of processing and storage requirements to support Minnesota services. The head-end application is used by the other Xcel Energy operating companies as they deploy advanced meters.

- Enhancement, construction, configuration, and installation of any required interfaces throughout all applications involved in the AMI solution to support Minnesota requirements.
- Design and integration of security into all aspects of the AMI solution.
- Thorough unit, system, integration, and end-to-end and regression testing of the AMI solution.
- User Acceptance Testing (UAT) with the Distribution, Customer Care and Customer Solutions business resources.
- Establishment of a full ongoing support structure including process and operational requirements.

2. AMI Network and Head-End System

After developing the business requirements, we began the procurement process for AMI. We issued an AMI RFP in July 2016, seeking proposals for network communications infrastructure, electric meters, and meter installation. We decided in early 2017 to focus our initial efforts on the AMI network communications infrastructure and head-end software and to de-bundle the meters and meter installation from the RFP and source those separately, following completion of the network communications and head-end contract.

Broadly, network communications encompasses the full suite of communications pathways used for a particular purpose, and may include radio frequency (RF), fiber optics, microwave, and ethernet, etc. In the context of the Company's grid modernization efforts, "network communications" refers to the FAN, which is used to enable communications between advanced meters and field devices throughout a given geographical area. The data to and from the advanced meters passes through the FAN and is then "backhauled" to the Company's systems that are not out in the field.

We sought vendor(s) that could supply a network communications solution to meet technical and operational requirements and also be agnostic to the advanced meter and meter manufacturer ultimately selected. This strategy would enable the selection of both the optimal network communication and the optimal advanced meter technology. Accordingly, and based on commercially available technology at the time, the successful network communication vendor would provide their Network Interface Card (NIC) hardware and be compatible with any selected advanced meter manufacturer.

In August 2016, we received responses from three network communications vendors and evaluated those responses against a number of factors including:

- Technical and operational performance,
- Resilience,
- Adequacy of security capabilities,
- System long-term survivability,
- Ability to design mesh systems,
- Implementation plan,
- Ability to meet schedule,
- Industry experience,
- Warranty and support,
- Acceptability of business terms and conditions, and
- Pricing.

In February 2017, we selected Silver Spring Networks, Inc. (Silver Spring) as the network communications vendor and began contract negotiations. Negotiations with Silver Spring were finalized in December 2017 and an agreement was executed with an effective date of December 19, 2017.

The selection was based on our evaluation of the factors listed above. In particular, Silver Spring offered the best combination of network performance with the most resilient and secure network. Another consideration was that Silver Spring had not historically been affiliated with an advanced meter manufacturer and its products were, consequently, compatible with meters from all of the major advanced meter suppliers. Finally, Silver Spring's use of the Wi-SUN specification conformed with Xcel Energy's strategy of using well-established, standards-based technologies.

In January 2018, Itron acquired Silver Spring. Prior to its acquisition by Itron, Silver Spring's independence from a meter manufacturer was unique. Following that acquisition, our selected network communications vendor was now owned by a major supplier of meters.

3. AMI Electric Meter RFP

Xcel Energy issued an RFP on March 8, 2018 (see Attachment 4B) to select an electric advanced meter vendor that could provide an advanced meter, project management, and installation services. As part of this advanced meter RFP process, we asked potential vendors to review our priorities, vision, and desired capabilities for our advanced meter solution. One requirement was compatibility with the Silver Spring network and the Wi-SUN wireless communications standard, meaning that the advanced meters would have to utilize and be integrated with the Silver Spring NIC. The vendors responding to the RFP were asked to provide detailed responses to numerous questions regarding their advanced meter offerings related to the following:

- Technical standards of their advanced meter,
- Capabilities of their advanced meter,
- Compatibility of their advanced meter with other components of the AGIS initiative,
- Data and cybersecurity safeguards,
- Plan and schedule for technology development, integration,
- Advanced meter deployment, and,
- Itemized pricing information for their advanced meter and installation.

We considered the option of acquiring meters from more than one supplier but ultimately determined that the efficiencies for meter maintenance and business systems resulting from standardization, along with the estimated benefits from the favorable terms Xcel Energy would be able to obtain through a substantial purchase from a single vendor, outweighed the advantages of not being reliant on a single manufacturer.

We received responses from four meter suppliers and evaluated the responses on a number of factors including:

- Total cost,

- Schedule requirements,
- Core metrology,
- Customer benefits and capabilities,
- Integration with the selected Silver Spring NIC,
- Adaptability in response to market and technological changes,
- Commercial terms and conditions, and
- Security.

In August and September 2018, meetings occurred between Xcel Energy and the four meter firms that had responded to the advanced meter RFP. Leading up to those meetings, we issued bid clarifications requesting additional information on the benefits the proposed advanced meters might offer to customers as well as updated technology roadmaps.

During the September 2018 meetings with potential meter vendors, we learned that some manufacturers were developing advanced meters with new, next generation computing capabilities, or, as it was called at the time, "edge" computing, "grid edge" computing technology, or Distributed Intelligence (DI). In response to learning about this developing new technology, we undertook serious efforts to gather additional information and evaluate the possible benefits of DI capabilities, including initial development of possible use cases for DI capabilities.

We determined that an advanced meter with DI capabilities would provide a pathway to expanded grid-facing and customer-facing benefits compared to first-generation advanced meters. Additionally, the platform that DI technology would establish would further ensure advanced meters purchased as part of the AGIS initiative would enable technology to evolve over time without the need to replace the meters as quickly as might otherwise be the case with first-generation advanced meters.

DI-capable meters would be able to remotely install new applications or upgrade existing applications in response to future developments such as changes in operational and/or customer needs and expectations or technological developments in the equipment that interacts with advanced meters. Given the speed of technological advancements, it was reasonable to assume that the likelihood of change over the expected service life of the advanced meters would be high. Therefore, we determined that the most prudent decision would be to acquire meters that can be adapted as technology progresses. As a result of the meter RFP process, it became evident that major meter manufacturers were considering DI as the future of advanced metering technology. Selection of a DI-capable meter would ensure Xcel Energy's advanced meters would provide our customers the greatest value for the longest time, thereby avoiding a situation where metering technology acquired would become outdated in a relatively short amount of time following deployment.

Our determination to require DI capabilities from our potential advanced meter vendors necessitated an amendment to the advanced meter RFP and the establishment of additional evaluation criteria focused on DI capabilities, their benefits, and the ability to deploy the technology, as well as the expected schedule for integrating the new DI capabilities with the Silver Spring network.

4. *Vendor Selection*

We initially selected **[PROTECTED DATA BEGINS**

PROTECTED DATA ENDS]

5. Electric Meter and DI Selection – Itron

In April 2019, we issued an RFP letter to Itron seeking a proposal for the supply of its DI-capable Riva meters, integrated with its Silver Spring communications network. After evaluation and clarifications, we selected Itron and its Riva Generation 4.2 (Riva 4.2) advanced meter. The primary factors in our decision to select Itron's Riva 4.2 meter were that Itron presented:

- The lowest risk and least complex solution for integration with the selected communications network,
- The ability to best meet the Company's advanced meter deployment schedule,
- A single vendor solution (Itron was already under contract for the communication network and the head-end software),
- The ability to meet or exceed Xcel Energy's core metrology requirements, including DI capabilities, and
- The most favorable overall commercial terms and conditions, including for DI technology.

We made the decision to pursue exclusive negotiations with Itron in May 2019. Ultimately, Itron and Xcel Energy entered into the following two agreements simultaneously.

- The Amended & Restated Major Supply Agreement for the Advanced Metering Infrastructure Project, effective September 1, 2019, and
- The Distributed Intelligence Platform Agreement, effective September 1, 2019.

We provide a summary of our selection as Attachment 4C, and supporting internal AGIS Sponsor Meeting presentation as Attachment 4D.

Finally, in response to the Commission's requirement that we explain if any of our contractors or equity partners have access to customer data, and if so, how that value accrues to Minnesota customers – we confirm no contractors or equity partners have access to such data to use for their own purposes. Thus, there is no value or compensation due to Minnesota customers.

IV. FIELD AREA NETWORK

In this section, we describe the FAN and its functionalities. We start with an overview of FAN in the industry, then discuss the FAN equipment itself, the Company's Wide-Area Network (WAN) and finally our process for selecting specific FAN technology.

The FAN is a wireless communications network that will leverage the Company's existing WAN and distribution infrastructure to securely and reliably address the need for communications capacity that arises from our implementation of new advanced grid devices, including AMI. The primary function of the FAN is to enable secure and efficient two-way communication of information and data between our existing WAN and IT infrastructure and the new AMI meters at customers' homes and businesses. The FAN will provide benefits to all AGIS and other future grid modernization initiatives, but is designed and built according to the needs of various components, and each has different communication network requirements. The FAN will provide the necessary capacity to support our deployment of AMI for electric meters in Minnesota, as well as provide the foundation for a scalable field radio network to meet Xcel Energy's growing field automation initiatives over time.

A. Field Communications in the Industry

The Company's FAN, composed of a Wi-SUN mesh and wireless backhaul, is consistent with developments within the electric utility industry and current industry standards that have been adopted by vendors, organizations, and other electric utility companies. We actively participated with industry standards organizations and alliances such as Electric Power Research Institute (EPRI) and Institute of Electrical and Electronics Engineers (IEEE) to ensure that our requirements and assumptions are aligned with the standards and products being deployed throughout the industry. In choosing the FAN technology, we relied on information from industry experts and systems integrators on actual installations of the FAN technology, public records on other utility implementations, and information through participation in industry research programs such as EPRI. The Wi-SUN network is a standards-based network solution that conforms to IEEE standards.

We benchmarked the communications solutions we are deploying with other utilities who have chosen to deploy similar solutions. Specific to the FAN, we concluded from our review of those utilities deploying AMI solutions that they also deployed a mesh architecture (which we discuss below) similar to the one we are deploying. The vendor of choice may vary, but the mesh architecture and deployment configurations have tended to be very similar. The exception for the Company is that it has chosen to deploy Distribution Automation (automated field controls and sensors) that require connectivity along with AMI connectivity with the mesh solution being deployed. Therefore, the mesh solution we chose (a multi-purposed, converged network) was determined and designed with that end in mind. This ensures maximum value for customers in that it will support the communications needs from a diverse set of device types.

We discuss specific alternatives that we considered as part of our discussion of our FAN strategy and selection process below.

B. FAN Components

The FAN is composed of three components, as follows:

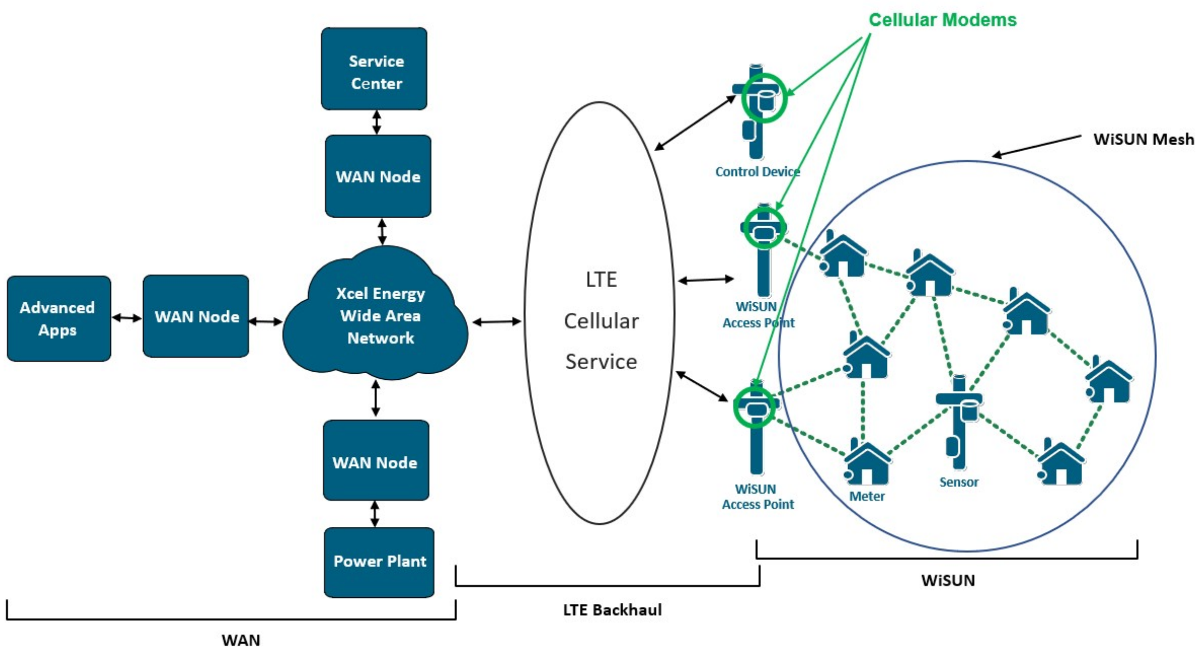
(1) a *mesh* Wireless Smart Utility Network (Wi-SUN) (between and among field access points and field devices that uses radio frequency (RF) technologies,

(2) a *backhaul* network that delivers data collected by the mesh network to the existing WAN, using varying wireless and wired communications technologies to deliver data to the third component –

(3) the Xcel Energy *wide area network (WAN)* or backbone, which uses Layer-3 networks (routers, switches, and circuits) to deliver data to and from the Company's information systems. The WAN contains the AMI head-end application, other advanced grid and business applications, and the Company's server and storage infrastructure.

Figure 4 below illustrates the FAN components.

Figure 4: Current FAN Strategy – Public LTE for Backhaul



We discuss the FAN components in more detail below, and clarify that the cost recovery we seek in this Rider request is for the Wi-SUN and backhaul components.[10]

1. The Wi-SUN Mesh

The Wi-SUN mesh network is the key network structure that will communicate directly with the AMI infrastructure and most Distribution Automation (DA) field devices. In addition to the embedded communication modules that will allow the AMI meters to communicate with the rest of the Wi-SUN network and that will act as endpoints, the core infrastructure for Wi-SUN consists of two main devices: (1) access points, and (2) repeaters. Both of these devices will be principally located on distribution poles and other similar structures.

- *Endpoint Devices*: include AMI meters. The AMI meters will be located on customer premises. In the future, endpoint devices may also include Distribution Automation (DA) field devices, such as intelligent FLISR field devices, that have built-in radios. Field DA devices will be co-located with either pole-mounted or pad-mounted distribution devices.

[10] The Xcel Energy WAN is an existing asset that is used more broadly than just for AGIS or other grid modernization communications.

- *Access Points*: devices that link the endpoint devices and that are enabled with wireless communication modules that communicate with the rest of the Company's communication network. The access points will wirelessly connect directly to the backhaul to pass data between the mesh network and the WAN. The access points will be located primarily on distribution poles and other similar structures.
- *Repeaters*: are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of Wi-SUN means that additional nodes on the network provide devices more options to communicate with their access point. Repeaters will be located primarily on distribution poles.

The access points and repeaters will be mounted primarily on distribution poles to provide adequate height for the radio signal to propagate. In areas where we have underground service, we will make arrangements to mount the devices on street lights or other structures with appropriate height.

The Wi-SUN mesh network, including the meters' communication nodes that will communicate as part of the network, will support AMI through the meters' communication function. The FAN will provide the transport for data transfer between the meters and the AMI head-end application, including interval customer energy usage readings, meter register reads, voltage information, and power quality data. It will also provide the sending and receiving of commands like power outage notifications and remote connect/disconnect commands. Once fully deployed, we estimate that the AMI meters will make up over 90 percent of the devices that will communicate as part of the mesh network.

2. *The Wireless Backhaul*

The backhaul portion of the FAN will transmit data from the Wi-SUN access points and connect to the Xcel Energy WAN via public LTE (cellular) service provided by recognized service providers such as Verizon, AT&T, etc. As we have explained previously, we initially intended to use WiMAX for backhaul, but a Federal Communications Commission (FCC) ruling effective April 2020 made using that frequency more expensive to operate (with high O&M service fees to the third parties mentioned above) and fast-tracked the extinction of WiMAX as a commercial offering.[11] The impact of the FCC rule effectively terminated the Company's (and other utilities') ability to utilize WiMAX technology as designed.

LTE modems will be installed in the Wi-SUN access points, and communicate bidirectionally across the service provider's network to the Xcel Energy WAN. Importantly, the data in transit will be encrypted at all times. And also importantly, our LTE-based backhaul solution will use modems that will work with any LTE service (public or private), is used by other utilities with similar requirements, and we have and continue to use it for other communications such as for Supervisory Control and Data Acquisition (SCADA).

In certain locations it will be necessary to supplement LTE with alternatives such as fiber or private LTE.[12] This could be because of lack of public LTE service or unfavorable geography. We identify these locations during our performance of field coverage studies of areas that will require FAN implementation to ensure the number, location, and configuration of network devices will adequately cover the full deployment. This will ensure the appropriate design for the network to support all devices being deployed that will require connectivity thru the FAN. This also provides the necessary information and data to file for permitting through the FCC for frequency and location of wireless devices.

C. Xcel Energy Wide Area Network

We already have a core communication network deployed, which as we have described, will serve as the final step for the FAN to communicate to and from the Company's systems. The Xcel Energy WAN is primarily composed of private optical ground wire fiber and a collection of routers, switches, and private microwave communications that are supplemented by leased circuits from a variety of carriers, as well as satellite backup facilities. It provides high-speed, two-way communications capabilities and connectivity in a secure and reliable manner between the Company's core data centers and its service centers, generating stations, substations, and offices.

The WAN will continue to be Xcel Energy's primary means of communicating data between the Company's data centers that house data and AGIS applications, such as ADMS, facilities such as generating plants and service centers, and the FAN. The

[11] This is because the cost to update hardware devices to meet FCC rules was cost-prohibitive, and caused U.S. vendors to abandon support of WiMAX in their products, thus forcing the Company to look for alternative technology in lieu of WiMAX.
[12] WiMAX would also have required similar supplementation to cover all locations and devices.

FAN, in turn, will provide the connectivity to intelligent devices installed across the distribution system.

D. FAN Strategy Development and Selection Process

The FAN strategy and RFP processes and vendor selections were the result of an enterprise-wide effort that began in 2010 to identify an appropriate communications solution to support advanced grid capabilities. We began engaging with vendors such as IBM and Accenture in 2010 to provide guidance and input on critical business applications that would or could impact the operations of the Company, and what network requirements could be defined to support those applications. Based on that work, we developed a detailed study of potential network efforts to support operations for the Company based on projected timelines and volumes for applications and associated network requirements. This was primarily focused on connectivity to devices in the field that would need to communicate with the applications identified. It also identified key requirements for reliability, security, and the need for two-way communications (i.e., not just monitoring systems, but also providing commands to those devices).

We refined this strategy over a two-year period. In 2012-2013, we began developing initial plans for the FAN through an organized effort with external vendors – comparing currently deployed network solutions to what will be needed for communications with emerging technologies such as ADMS, AMI, and FLISR and other grid management and customer support solutions. At that time, virtually all network solutions were proprietary solutions based on the devices or applications being deployed.

In 2013, based on the preliminary work described above, we formalized the FAN strategy into a program. Key guidelines for the RFP/RFI processes included the following:

- Leverage Xcel Energy-owned assets such as WAN connectivity to substations as well as network components in data centers and communication hubs;
- Design to capitalize equipment for full control,
- Unify equipment and services across all operating companies,
- Follow and embrace industry standards for all tiers of networks,
- Carefully integrate and coordinate network control and monitoring systems, and

- Plan and build without compromise for security controls.

The FAN team also recommended the following technical requirements:

- Point-to-Point microwave and fiber for connectivity to FAN,
- WiMAX technology for wide area broadband services,[13]
- Mesh networking for AMI and deep access to electric, gas, and street-lighting controls,
- Rigorous attention to standards and interoperability, and
- Continued review of technology on an annual basis to ensure future proofing.

In the 2013-2015 timeframe, we prepared and executed detailed RFIs and RFPs for the network solutions to support the business applications.

1. Technology Selection Process

We employ standard processes and procedures for selecting technologies to be deployed in the Company's environment, as well as the execution of large capital projects. We used these standard processes for selection and deployment of the FAN, as follows:

- *Product Selection – Mesh*: The Company awarded a contract for the Wi-SUN mesh network in 2017 to Itron after an extensive and thorough competitive RFP process described below. In addition to the RFP process mentioned, the Company also provided the platform and facilities for each RFP responding company to demonstrate their claims in the RFP in a test environment. The RFP responses and the test results were the primary input the RFP award.
- *Product Selection – Backhaul*: For the backhaul aspect of the FAN, we issued and awarded an RFP for the WiMAX primary vendor in 2015 and awarded a contract for this part of the FAN solution in 2017. This process ensured the most optimal solution for the Company's needs, and the Company negotiated a contract with reasonable costs.
- *Provider Selection – Implementation Services*: The RFP was bifurcated such that the vendors would propose technology (hardware and software) and

[13] As discussed below, the Company had to change its strategy away from WiMAX after an FCC rule change effectively eliminated WiMAX as an option for the backhaul.

implementation services separately. Ultimately, a single vendor was selected for both technology and implementation services.

As we have discussed, we later had to change our approach on the backhaul solution after an FCC decision made using the frequency used for WiMAX more expensive to operate and fast-tracked its extinction as a commercial offering. For the replacement backhaul solution, we will use our existing provider for public cellular communications for other field communications needs.

2. *Request for Information/Proposal*

Xcel Energy issued a Request for Information (RFI) to ten vendors regarding the technology and services necessary to build a wireless FAN, including the mesh network and the AMI head-end application – See Attachment 4E. We also commissioned studies from industry experts, including Electric Power Research Institute (EPRI), IBM, and Gartner, Inc. After analysis of the RFI responses, four vendors were selected to receive an RFP to become: (a) the FAN technology supplier (hardware and software), and (b) the services provider to perform the implementation.

The vendors were asked a standard set of questions in nine categories addressing the following qualitative (non-cost-related) evaluation criteria:

- Quality of references
- Ability to interoperate with 3rd party devices
- Propensity to follow industry standards
- Proponent's technical solution
- Operational performance
- Adequacy of security capabilities
- Offered warranty and support
- Manageability with operational model
- Ability to design mesh network systems
- Ability to implement mesh network systems
- Ability to meet project scope and schedule
- Acceptability of business terms and conditions
- Corporate structure, organization, and industry experience
- Adequacy of support systems

Each category was assigned a weight of importance (collectively totaling 100 percent). The quality of each answer was assigned a score. In addition, vendors were invited to demonstrate their approach in an Xcel Energy test environment, including interoperation with existing third-party systems and components.

Two vendors were excluded due to lack of adherence to standards. This was a crucial requirement to ensure interoperability with third-party devices and systems, and to avoid becoming locked into a single vendor. The successful candidate for both technology and services was Silver Spring Networks, which was subsequently acquired by Itron, Inc. in 2018. Major reasons for our choice include:

- Favorable pricing,
- Industry experience and track record with other utilities Xcel Energy benchmarked against,
- Performance in on-site testing of products against the requirements in the RFP,
- Breadth of solution, and
- Interoperability capabilities.

3. Recommended Solution

As we have explained, the Company's FAN, composed of a Wi-SUN mesh and public LTE wireless backhaul, is consistent with developments within the electric utility industry and current industry standards that have been adopted by vendors, organizations, and other electric utility companies.

The WiSUN mesh is an inherently resilient design. The mesh network allows multiple devices to connect with each other, which provides multiple potential communication routes, ensuring a robust communications network. In most cases this communication will be with the Wi-SUN mesh radios via the Institute of Electrical and Electronics Engineers (IEEE) 802.15.4g standard.[14] This standard for local and metropolitan area networks is well-accepted in the utility and communications industries. Wi-SUN can wirelessly connect meters, sensors, distribution devices, street lights, and signal repeaters to create a robust and reliable wireless network. Xcel Energy, on behalf of NSPM and its other operating companies, participates as a full member in the Wi-SUN Alliance with other utilities and equipment manufacturers. By selecting a technology that conforms to the IEEE standard, we are ensuring the interoperability of the FAN with other systems.

[14] IEEE 802.15.4.g is intended to be a global standard that facilitates very large scale process control applications such as the utility smart-grid network.

The public LTE backhaul is a proven solution in use by other similarly-situated utilities. Because every device in the mesh will have access to more than one access point, and therefore more than one LTE modem, a failure of an access point or modem will not result in a loss of communication. If in the future the Company decides to move from public to private LTE, the LTE modems will support private LTE by simply replacing Subscriber Identity Module (SIM) cards.

Our FAN solution allows the Company to control the integrity of the devices on our network and the data exchanged with those devices. The vendors were selected using a rigorous process that included both a traditional RFP and proof of concept demonstrations within the Company's environment.

4. *Alternatives*

The principal alternative to the Wi-SUN mesh aspect of the FAN for supporting AMI is the use of cellular carrier solution, which would eliminate/replace both the Mesh and the Backhaul aspects of our chosen FAN solution. This approach would require the Company to deploy a cellular modem in every meter, and pay monthly fees for usage and for the private internet protocol service for every device. This would result in the Company incurring substantial monthly and annual expenses. In particular, when comparing cellular carrier solutions for this aspect of the FAN, we determined that device costs (a cellular modem compared to the NIC) were fairly similar, but the ongoing annual expenses would be considerably higher with the use of a public cellular network. Although the LTE wireless backhaul also requires fees for carrier services, the number of modems (and therefore service fees) is dramatically smaller than an all-LTE design. Other criteria we considered in selecting the Wi-SUN Mesh included security, reliability, support costs and latency requirements. Latency refers to the time it takes for data to pass from the devices through the cellular network to our applications at our data centers, and then back out to the devices. A cellular solution in lieu of the Mesh would create an extended period of time (latency) that does not meet the Company requirements for some applications.

Another alternative would be to develop a dedicated AMI communications network, meaning a specific network for the singular purpose of supporting only meters and AMI. In this case, devices that would make up the network would be dedicated only to AMI and be proprietary in their design and operations. When comparing this option to the FAN, we determined the FAN is more functional and preferable because it is based on industry standard communication protocols and allows for connectivity of diverse devices (meters, capacitor banks, sensors, etc.). Allowing devices to connect both to each other and to back-office applications not only increases the ability to conduct peer-to-peer communications on a local feeder, but also reduces overhead associated with managing, supporting, and monitoring multiple networks of diverse manufacturers and network management tools.

We concluded that none of the communication network alternatives could match the features and capabilities of the FAN network we designed. We provide a summary of our selection as Attachment 4F.

V. ACTIONS TO MANAGE COSTS AND MITIGATE RISKS

In this section, we outline the actions we have taken to manage costs and mitigate risks for the Company.

We have taken a number of actions to minimize costs and maximize value for our customers. We used competitive sourcing processes, selected metering technology that is open standards-based, and obtained DI capabilities without incremental cost above the meters themselves. We also designed a FAN that uses open standards based communications protocols that give the Company flexibility over proprietary technologies for comparable cost. Additionally, through our contract negotiations, we secured the following favorable terms:

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

We also employed standardized processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These processes are designed to ensure that the Company is both containing costs appropriately and spending money on the items necessary to achieve the desired outcomes and overall reasonable costs. These standard processes include:

- *Product Selection* through RFP processes, as described in detail above, which is intended to identify the optimal solution for the Company's needs, followed by negotiations to achieve the best price for the Company and our customers.
- *Project and Initiative Governance Processes* that facilitate project scope and cost management.
- *Contingency* that will be refined as the project progresses and more details are identified, which is prudent to present an anticipated cost level that is achievable. The use of the contingency is closely managed and subject to internal approvals.

To ensure project success and prudent spend, we have also taken and will continue to take the following steps:

- Engage in benchmarking with peer utilities in the industry,
- Leverage industry leading technology experts,
- Utilize key business partners in robust sourcing processes,

- Establish formal internal governance structure that includes senior business leadership executives,
- Establish rigid decision processes and financial governance including rigorous project change request and approval processes, and
- Select an initiative level business management consultant to further support the overall governance and management of the projects.

The AGIS initiative is a significant cross-functional effort and requires coordination to ensure we manage our costs and maximize value for our customers. To help us achieve our desired outcomes, we utilize a variety of program management and governance processes to ensure alignment of the enterprise vision and drive cross-workstream integration of the AGIS initiative. All key AGIS initiatives follow these program management processes including decisions involving program design, scope, schedule, modifications, resource allocation and benefit-realization.

Large, complex initiatives like AGIS must have established controls due to the size and highly interrelated and interdependent nature of the many components of this initiative. Significant program management oversight is needed on an ongoing basis to ensure the effective use of resources, and thus optimal costs for the scope and benefits intended. The established procedures include management of processes, metrics, and reporting. A dedicated team has been established to develop, manage, and ensure quality and compliance to our AGIS initiatives.

There are various aspects of program management, some that are specific to a business area; while others are applicable across all functional areas involved in implementation. Program Management functions include Business Readiness, Change Management, Finance, Program Management Office, and Supply Chain. Program Management accountabilities are described below by function:

- *Business Readiness.* Ensures the business is ready to operate and sustain the new processes and technology. The Business Readiness function ensures that the technology meets the expectations of the business and that the business is appropriately prepared for the deployment of that technology. The overall goal of the Business Readiness function is to protect the value of the investments by ensuring the new technology is integrated seamlessly into the Company's day-to-day business.

- *Change Management.* This is a systematic approach to effectively execute and manage the fundamental organization and process changes, such as when an electric utility implements a significant change to the distribution grid.
- *Finance.* Provides forecasting, budgeting, and reporting on the financial performance of the projects and the AGIS initiative. This includes reporting on various metrics and providing support in regulatory filings.
- *Program Management Office.* Coordinates governance activities for the projects and the overall AGIS initiative. This includes reporting on current project status, requirements for project change requests, and control of policies and guidelines designed to effectively govern the projects and AGIS initiative.
- *Supply Chain.* Provides centralized supply chain support, including negotiation of large strategic contracts and issue resolution.

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

The project planning life cycle is broken into phases; Strategy, Planning, Initiation, Blueprinting, Design, Build, Test, Deploy, Warranty. Once a project has been initiated, each phase of the project's health is peer-reviewed weekly. The weekly review includes schedule, milestones, issues, risk, and budget. The Project Management office conducts a peer review of the overall AGIS budget monthly and results are reviewed by management.

These structures and protocols help ensure the projects are completed according to the established scope, schedule, and budget. Program Management integrates complicated activities across multiple projects, business units, states, and operating companies to ensure efficiencies are leveraged and the end product delivers the desired benefits to the customers. Financial management functions ensure projects are executed within budgets and variances are promptly escalated for remediation plans.

VI. SECURITY AND RESILIENCY

A. Overall Approach to Security

The Company has a dedicated Enterprise Security and Emergency Management business unit that encompasses both cyber and physical security, security governance and risk management, and enterprise resilience and continuity services. This combination of services is designed to cover analysis of vendor risks, alignment of the technology with security standards, secure solution design and deployment, integration with Company solutions including user access management and system monitoring and incident response, as well as threat analysis and planning for continuity of business operations in the event of a disruption. The Company's security risk management program provides Company leaders with information about threats and the level of security risks, so that mitigations and responses can be planned that are proportional to the risk.

Generally, our security practices include a security controls governance framework, which leverages industry best practices including the National Institute of Standards and Technology (NIST) Cyber Security Framework (CSF). The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect the confidentiality, integrity and availability of information and systems. A rigorous vendor security risk assessment process helps to reduce supply chain risk.

We implement cyber security controls not only for systems within the enterprise data centers but also for the intelligent devices (including meters) and communications networks outside of the company premises. Where technically feasible, these include but are not limited to user access controls, encryption, firewalls, Intrusion Detection and Prevention Systems (IDS/IPS), vulnerability and patch management, system change and configuration management, monitoring, and incident response planning.

The NIST CSF outlines five categories of controls that entities should employ to create multiple layers of protection: identify, protect, detect, respond, recover. The Company undertakes a variety of actions consistent with these controls, including defenses at each endpoint and throughout the network. At an enterprise level, the Company's actions include:

- *Asset management* – the Company maintains an inventory and securely configures assets, so we know what to protect as well as what is authorized to access our networks [Identify],
- *Protection* – The Company employs user access controls, encryption, digital certificates and other controls to ensure the confidentiality, integrity and availability of data [Protect],
- *Vulnerability management* – in addition to scanning equipment for known security vulnerabilities, the Company monitors emerging threats [Detect],
- *Monitoring and alerting* – the Company takes steps to identify potentially anomalous activity so that both proactive and reactive responses are appropriate and efficient [Detect],
- *Incident response* – the Company analyzes information using playbooks and escalates incidents to the Enterprise Command Center—the Company's 24x7 watch floor operation designed to prepare for, respond to, and recover from any potential hazard that may impact customers, Company assets, operations, or its reputation [Respond], and
- *Disaster recovery and business continuity planning* – the Company has plans to efficiently maintain and restore grid operations in the event of a cyber-attack [Recover].

We will apply these controls to identify and protect all components of the intelligent grid, just as we do for the rest of our systems and assets to help ensure the reliable and safe delivery of energy to our customers, as follows:

- *Endpoint Protection* – the installation and/or enablement of protective and detective cyber security controls to thwart malware and external influences from causing unexpected, unwanted or invalid behavior at an endpoint. These were specified as cyber security controls in the AMI vendor selection process, as they are essential to protect the devices and the data that are handled by AMI meters and head-end servers.
- *Access Control* – confirms that only necessary and authorized users have access to the individual devices. This not only includes the devices that are installed on the consumer's premises, but also the devices that facilitate communication and control of the data flowing to the consumer. There are potentially many avenues of compromise with respect to unauthorized access to devices. This is

a key consideration and will be addressed through strong authentication methods, which include multi-factor authentication.

- *Authentication* – a method by which a user affirms their identity. In its simplest form, it involves a user ID and password. Where technically feasible, Xcel Energy requires multi-factor authentication so that a user must not only know their password, they must also possess a physical or logical token. This minimizes the ability of an unauthorized user to steal passwords and access our assets and information.
- *Authorization* – the process of determining and configuring the minimum level of access required by a user or an automated system. Granting undue permissions to devices that comprise the intelligent electric distribution system could lead to unauthorized or inadvertent changes and instability. Complying with a least-privilege principle ensures that only necessary and authorized individuals have the ability to make administrative changes.
- *System and Patch Management* – addresses the periodic manufacturer updates to software and firmware to improve performance, add features, or address security vulnerabilities. A robust system patch management process incorporates asset inventories, secure receipt of patches from the vendor, testing and deployment to the field. The Company's threat intelligence and vulnerability management teams monitor for and inform support teams of known security vulnerabilities that require patching. Keeping current with vendor patches helps reduce the possibility that a criminal can use a known exploit to compromise our systems or data.
- *Data validation* – a final defensive layer between the various endpoints. As data are sent from endpoints at consumer premises, data validation at the head-end must take place. If data values received from the consumer endpoint do not fall within a range of expected values, then either the data must be assumed compromised and discarded, or secondary validation must take place to measure the integrity of the data received. This validation will provide yet another level of detection and protection for the intelligent electric distribution system.

B. AGIS Security Approach

Overall, while the implementation of the AGIS and other grid modernization initiatives will provide the Company and our customers with powerful new tools and access to granular energy usage data, it also presents new challenges to security when compared to a less advanced grid. It, thus, requires its own comprehensive security strategy. This strategy starts with identification and protection of all components of the intelligent grid, both for the protection of customers and for the reliable and safe delivery of energy to customers. First, devices in the field must be protected. Unlike internal business technology, the distribution components of our AGIS investments are out in the field and at customers' residences. Because these assets are outside the Company's physical facilities, security must rely on controls we may not otherwise commonly lean on. For example, detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity.

Additionally, although even legacy distribution systems and meters are vulnerable to physical tampering and disabling, a communications network that provides additional capabilities and services to our customers, as well as greater insight into our system, increases the potential impact of a security compromise. That said, we are designing security controls for each component and system implemented. These security risks can be organized into three primary areas: compromise of meters and devices; exploitation of communications channels; and security lapses once data are within the corporate environment. There are also security risks related to cloud-based components including the customer web portal, as well as future customer applications and new products and services that will be enabled by the advanced grid that we are also proactively addressing prior to implementation.

We have based our controls on a security controls governance framework that leverages industry best practices including the NIST CSF. The Company's security policies and standards incorporate regulatory compliance requirements and security controls designed to protect against Confidentiality, Integrity and Availability (CIA) breaches. This framework serves as the basis for project security requirements as well as periodic internal security technology control assessments.

C. AMI and FAN Infrastructure and Communications Overview

In this section, we discuss key controls at various points of the AMI infrastructure. These components, starting at the meter, are as follows:

- The meter sits at the customer premise, gathering metrology data to be sent to the head-end for billing purposes. The meter may also employ DI agents, to gather information for electric grid optimization, or to provide the customer with additional information and capabilities for managing their energy usage.[15]

[15] A DI Agent is an application (app) that resides on the meter itself.

- The meters are a part of the FAN. FAN communications end at an access point, which forms the transition from FAN to WAN and the company's internal network.
- Once on the Company's internal network, data may move between network segments as allowed by firewalls and other security controls. Ultimately, data are stored on servers that reside in Company data centers or are securely moved to secure locations in the cloud.
- The Company employs layers of security controls to protect the CIA of data throughout this journey.

We discuss these infrastructure components below.

1. *At the Meter*

Our Company and AGIS security approach is one of "defense-in-depth." The advanced meters will be physically sealed and monitored to detect tampering. Customer usage data are well protected on the meter. Attempts to physically open or otherwise access a meter trigger tamper alarms. No customer-identifying data are held in the meter. DI agent processing is primarily done in dynamic memory rather than stored on the meter. The Company has performed extensive security penetration testing in these areas, as well as to confirm the separation of metrology data and communications from that used by DI agents.

Advanced meters and other networked devices have network interface capabilities that enable them to connect to the FAN. We leverage both physical and cyber security controls to protect these network interfaces from unauthorized access. Second, a compromise of the FAN communications that carry "traffic" to and from the meters and field devices could lead to disruption or alteration of information needed for grid management. Therefore, it is critical that we protect the integrity of the communication devices and channels that allow the advanced grid to perform at expected levels. It is also important to implement the correct level of monitoring and alerting, configured to identify potentially anomalous activity, so that both proactive and reactive responses are appropriate and efficient. Third, the primary risk to systems and information that reside within the Company's corporate environment is from unauthorized access – where a criminal or unqualified employee accesses sensitive data or issues commands to the grid. There are many controls in place to detect and prevent such behavior, including segmenting the AMI system from the corporate business network.

Meter communications will be encrypted to protect the privacy of our customers, as will the other communications that travel on the FAN from and between the authorized devices that have been registered onto the network. Firewalls control the information that travels in and out of the corporate network. The AMI head-end will validate the integrity of the data received. We will actively monitor the communications path between the meters and the Company data centers to promptly detect and respond to any anomalous activity. Additional monitoring of the head-end system will trigger alerts for investigation.

2. On the FAN

The equipment that makes up the FAN deploys the endpoint protections discussed above. Additional key controls for FAN include the use of firewalls to restrict which systems can interact and what ports and protocols they can use; encryption to minimize the opportunity to intercept and alter data traffic on their way to the AMI head-end; monitoring and log review, as well as response to suspected security events. All member devices on the FAN have digital certificates, which prohibit rogue devices from joining the network, so traffic cannot be rerouted or invalid information injected into the network. The mesh portion of the FAN is also Company-owned, granting the Company the control to deploy and monitor security settings.

Firewalls are placed in multiple areas of the network between the customer meter and the company data center/head-end. By default, all traffic through a firewall is blocked, and authorized only after a thorough review and change process. With a firewall, any unauthorized, unregistered devices that attempt to join the network or communicate to/from devices are blocked.

Encryption uses complex mathematical algorithms to obscure data prior to and during its travels through the communications network. It also prevents data from being altered. Only authorized parties to the transaction (sender and receiver) have the "keys" to encrypt and decrypt data. For example, meter readings are encrypted the entire way from the meter to the AMI head-end to protect the privacy and integrity of that information.

3. Company Systems and the Internal Network

The Company systems comprising and supporting AGIS reside in data centers with physical access protections – only authorized users are able to enter these locked facilities on Company property. Data accessed from the control centers travels from the systems in the Company data centers over the Company network. At the control center, application users must follow the same rules for authentication, authorization, and least privilege.

Data from the intelligent electric distribution network pass through multiple defense-in-depth controls on their way back to the systems in the corporate data centers. Communications will pass through multiple firewalls to ensure that only authorized devices are communicating on authorized ports/protocols. Additionally, a protocol-aware Intrusion Detection System/Intrusion Prevention System (IDS/IPS) will inspect the traffic to identify and block known malware. Once the data have been delivered to the systems responsible for consuming this information, only authorized processes will have the ability to act upon this information.

The Company segments its networks, so that critical operational systems and information are kept separate from business data and operations including email. This segmentation adds a significant barrier should a criminal compromise a corporate user's account. In addition to using firewalls between networks, the Company requires the use of multi-factor authentication when accessing systems from outside the control center.

After clearing firewalls, data from the FAN are routed through the internal network (and more firewalls) to the AMI head-end. Meter readings are sent to other systems for processing and preparation of bills. DI data are sent to an application server in the data center which sits in a secured network segment Demilitarized Zone (DMZ) where it is accessible to Company users and to Itron, which is responsible for management of that server, including patching and other security controls required by Company.

Physical access to the Company data centers is tightly controlled and periodically reviewed for business need. Data in systems controlled by the Company are protected with layers of controls, including but not limited to access, encryption, monitoring, vulnerability, and patch management, change and configuration management, and incident response planning.

4. *In the Cloud*

The Company has chosen to host some elements of the AMI solution in the Cloud. Portions of the DI solution are only available in the Cloud. The Company requires that vendors of cloud-hosted applications undergo a rigorous security assessment and meet the same security standards required of systems that are on premises. Additionally, transfers of data to/from the Cloud elements are done via secure mechanisms.

In summary, we take our responsibility to protect the privacy and security of our customers, grid, and information systems seriously. We have based our controls on a security controls governance framework, which leverages industry best practices. We will take a defense-in-depth approach that will apply controls at many levels to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to our customers.

VII. PROJECT BUDGET AND COST RECOVERY

The project costs associated with AMI and FAN include both capital and O&M components and fall into the following primary components: AMI Meter-related, Communications Network, IT Systems and Integration, Program Management, and AMI Operations. Because the AMI and FAN solutions are being developed as one solution across the Xcel Energy enterprise system and being implemented in each specific operating company on a different timeline, a portion of the costs will be allocated to specific operating companies and jurisdictions. Below, we outline the cost categories and how we developed the forecasted costs for each; we also discuss the components of the AMI and FAN initiative that are subject to an allocation process, and the specific budgets for applicable components in Minnesota.

A. Project Cost Development

In this section we generally outline each of the categories of costs and how we developed the respective cost estimates.

1. AMI Meter-Related Costs

This category includes contractual costs for AMI meters, meter installation and vendor project management costs, and the people that are managing the AMI Operations and any customer claims that may result from the project. Other costs in this category include AMI operations and estimated costs associated with "returns to utility." These are AMI meter installations that the deployment vendor is not able to complete for some reason – so it "returns" those to the utility for resolution and is partially compensated for attempted work as agreed to contractually.

We outline below how we developed the estimated costs for this part of the AMI and FAN initiative. We also note that the projected costs associated with project employees are based on typical Company wages, and contractor costs are costs of contractors at estimated wage scales. The costs to fix and replace broken and damaged equipment are based on expected failure and damage rates for these devices.

Further meter-related cost estimate assumptions are as follows:

- *AMI meter cost* - Based on blended weighted average cost across multiple residential and commercial type meters plus estimates for taxes and overheads for things such as minor materials e.g. rings, seals, etc.
- *AMI meter installation costs* are based on a weighted blended average cost across multiple residential and commercial type meters plus overheads.
  - We estimate the meter install vendor (MIV) will install approximately 97 percent of AMI meters and 3 percent would be exchanged by internal or non-MIV contractor. We further estimate the 3 percent of exchanges would cost twice as much as the cost of the MIV to account for possible return to utility (RTU) jobs and higher costs for non-MIV resources completing the work.
- Costs for *vendor project management* were based on total costs provided by the meter vendor as per the contract. These costs are spread out across the deployment years.
- *AMI operations* (internal and external labor) labor costs were developed based on role and number of personnel required to perform tasks to enable installation and deployment of AMI meters. The necessary positions include but are not limited to project managers, engineers, analysts, field deployment supervisors, office contractors, schedulers, etc.
- Estimates for *Lab equipment* were based on quotes obtained and purchases made from our existing vendors for this testing equipment. This testing equipment is standard off-the-shelf equipment and we leveraged our relationships with our existing vendors to obtain the best cost.
- Estimates for *small claims* were developed based on input from industry peers.

The AMI project team also estimated additional costs for repairs that would be required to be performed by the Company to support safe installation of the AMI meters. These are repairs that are ordinarily performed by the Company (e.g., repair of stressed or tight wires at the service) on an as-needed basis. These estimates do not, however, include the costs related to damaged customer-owned equipment that we discuss in the Implementation Section (X) below and, as we explain, that we intend to do on behalf of our customers. Our current budget of $1.7 million is specific to correction of Company-owned equipment, so we will be adding dollars to this budget category in anticipation of expected levels of repairs of customer-owned equipment in our next/2022 budget process. We expect to increase the 2022 budget from its current $1.7 million to somewhere between $3.4 and $5.2 million to ensure it is sufficient to cover both Company- and Customer-owned equipment corrections. We based this estimate on our experience thus far with our PSCo affiliate's deployment and the Minnesota TOU rate/Flex Pricing pilot deployment.

2. Communications Network

This category includes costs associated with the FAN infrastructure, including both Distribution- and Business Systems-related costs. FAN implementation requires installation of Wi-SUN equipment in the field as well as implementation of the necessary software components and IT integration with the Company's other systems. The FAN budget has two key components: (1) labor, and (2) hardware.

a. Labor

We derived the labor costs utilizing pricing gained from industry benchmarks and reviewed with other utilities and industry research organizations such as EPRI. These costs were also analyzed and reviewed as the result of the limited deployment of the FAN that tested out the technology, the deployment process, monitoring, and performance. As each stage of the FAN deployment is conducted, the labor costs and estimates are reviewed on a per-site basis and forward-looking estimates are refined. These costs will be reviewed and refined throughout the lifecycle of the project. Labor cost types include installation labor, Radio-frequency (RF) design, configuration and testing, planning engineering, project management, and network services.

The FAN is primarily a Business Systems effort, with some involvement by Distribution as follows:

- Lead the design of the network systems (Wi-SUN, LTE wireless backhaul);
- Procurement and installation of all hardware components that will operate the network. This task is a joint effort between Business Systems and Distribution

in the procurement and deployment of the hardware components. Distribution is responsible for installation of the Wi-SUN devices (access points (APs) and repeaters), which will be located on Distribution poles;

- Configuration of the software and hardware;
- Designing and integrating security into all aspects of the FAN solution;
- Thorough unit, system and end-to-end testing of the FAN solution;
- User Acceptance Testing (UAT) with the Distribution, Customer Care and Customer Solutions business resources; and
- Establishment of a full ongoing support structure including process and operational requirements.

b. Hardware

To determine the hardware requirements and installation costs for the FAN, Engineering performed a preliminary Radio Frequency Network Study. The purpose of this study was to determine the location and number of Wi-SUN equipment (access points (AP) and repeaters), and, at the time, WiMAX devices that would be required to facilitate a reliable FAN communication network for the AMI meter and the distribution automation devices. The study concluded that approximately 550 access points, 3,000 repeaters, and 2,500 Customer Premises Equipment (CPEs) would be required for the FAN coverage area. We used this information to calculate our estimated hardware costs. The current deployment that will now use public cellular for the backhaul eliminates the need for CPEs and instead includes the use of cellular modems to connect the Access Points (APs) to the backend systems via a public cellular provider. These devices will match up to the counts for AP's (500) and include the cost of the cellular modem and the monthly data fees for each device. These process and forecasts are based on pre-established pricing standards and the results of the RFP specific to FAN devices and vendor negotiated rates.

Implementation of the FAN will also involve O&M costs for infrastructure and hardware, operations (including equipment and personnel), and preparation costs. These costs include the field level support for fixing broken and damaged equipment, additional personnel to monitor and manage the FAN, other preparation work that is designated as O&M, hardware and software maintenance, and training. Personnel will include both Company employees and contractors, which will be used based on workload, location, and timing. Most incremental work will be performed by contractors.

3. *Program Management*

The costs included in this category include Change Management, Release Management, project Finance and the Project Management Office, Security, Supply Chain, Talent Strategy, and Project Delivery and Execution Leadership. We discussed these governance and other administrative functions in Part V above. We outline how we developed the project cost estimates for each below.

a. Change Management

This is a systematic approach to effectively execute and manage the fundamental organization and process changes, such as when an electric utility implements a significant change to the distribution grid. The costs associated with this function are primarily labor, comprised of both internal and external resources that identify the change impacts and implement change management plans that help individuals, teams, and organizations in making organizational change. We estimated these costs using a bottoms-up approach based on resources and roles required and consulted with a third party specializing in change management. These costs were then compared to previous experience on other capital projects.

b. Business Readiness

Ensures the business is ready to operate and sustain the new processes and technology. The Business Readiness function ensures that the technology meets the expectations of the business and that the business is appropriately prepared for the deployment of that technology. The overall goal of the Business Readiness function is to protect the value of the investments by ensuring the new technology is integrated seamlessly into the Company's day-to-day business. We do this by ensuring the business is ready to implement the new processes and technology. Business readiness staff work with the business to plan and execute the following; product and service readiness, meter readiness, external stakeholder readiness, security readiness, operational support readiness, network readiness, application readiness, support readiness, and deployment readiness. The costs associated with this function are primarily labor, comprised of both internal and external resources that facilitate readiness activities. We estimated these costs by defining the business readiness needs for all project activities and developing a resource plan to support transition to the new end state. We utilized a third party with expertise in business readiness in resource plan development.

c. Finance

The Finance function provides forecasting, budgeting, and reporting on the financial performance of the projects and the AGIS initiative. This also includes internal reporting on monthly metrics and providing support for regulatory filings. The costs associated with this function are primarily internal labor. We estimated these costs by determining the scale of financial support needed to execute AGIS functions and building a resource plan that supports these functions.

d. Program Management Office (PMO)

The PMO coordinates governance activities for the projects and the overall AGIS initiative. This includes reporting on current project status, requirements for project change requests, and control of policies and guidelines designed to effectively govern the projects and AGIS initiative. We do this by providing governance, project controls, project services, sourcing management, resources management, and program delivery services. These services are provided for two business units executing projects in eight states among four operating companies and include plan, design, execute, and closure phases. The costs associated with this function are primarily labor, comprised of both internal and external resources that manage and govern the AGIS program. We estimated these costs by determining the services that would be provided by the PMO and developing a resource plan to support these services. We leveraged previous project PMO experience and a third party with expertise in project management offices to develop the plan.

e. Supply Chain

The Supply Chain resources provide centralized supply chain support, including negotiation of large strategic contracts and issue resolution. The costs associated with this function are primarily internal labor. We estimated these costs by defining the expected volume of sourcing activities and aligning resources to these activities.

4. Information Technology Systems and Integration

This category includes estimated costs for AMI product software, development of new interfaces and updating of existing integrations, performance and scalability tests, and project management costs. We outline below how we developed the estimated costs related to the implementation and sustainment of AMI software to support the meter deployment and customer billing. We also note that the projected costs associated with project employees are based on typical Company wages, and contractor costs are based upon established agreements for each resource type.

Assumptions used in development of the cost estimate are as follows:

- *AMI head-end (UIQ)*. Based on contract pricing with Itron regarding the endpoint licenses required to operate AMI meters on the head-end software. Endpoint licenses will be charged directly to NSPM upon deployment of the meters. Also includes estimated labor (employee and contractor) to implement software solution, which will be charged to NSPM through the cost allocation methodology discussed in Section VII.B below.
- *AMI IEE Meter Data Management System (MDMS)*. Based on contract pricing with Itron regarding the endpoint licenses required to operate AMI meters on the meter data management system. Endpoint licenses will be charged directly to NSPM upon deployment of the meters. Also includes estimated labor (employee and contractor) to implement software solution. Costs are incurred at the enterprise level and allocated to each Operating Company based upon standard software allocation methodology, similar to the construction of the ADMS software.
- *AMI Meter Data Lake (MDL)*. Based upon licensing costs negotiated with KX to provide background database support for the MDL. Endpoint licenses will be charged directly to NSPM upon deployment of the meters. MDL is the data repository that will support long term analytics and reporting requirements. Includes estimated labor (employee and contractor) to implement software solution and build out required reports. Costs are incurred at the enterprise level and allocated to each Operating Company based upon standard software allocation methodology, similar to the construction of the ADMS software.

- *AMI Rate Factory*. Rate Factory provides all of the billing rates approved for each Operating Company, across residential and commercial rates, along with the upcoming Net-Meter rates. Based on the estimated labor (employee and contractor) to develop rate schedules used by the AMI head-end in billing calculations, which will be charged to NSPM through the cost allocation methodology discussed in Section VII.B below.

- *AMI Outage Management*. Using Itron's Outage Detect System (ODS), Itron ODS provides AMI outage message pre-processing, which improves the quality of outage-related messages received from AMI meters such that action can be taken in the Distribution Control Center using Oracle Network Management

System (NMS). Based upon contract pricing with Itron regarding the endpoint licenses required to operate the ODS on the head-end software and includes estimated labor (employee and contractor) to implement software solution, all of which will be charged to NSPM through the cost allocation methodology discussed in Section VII.B below.

- *Development of New AMI Interfaces and Integrations.* Scope of work was developed based upon extensive architecture and requirements development sessions using employee and contractor labor. Costs for development of required interfaces and integrations estimated on employee and contractor rates, which will be charged to NSPM through the cost allocation methodology discussed in Section VII.B below.
- *Performance and Scalability.* Scope of work was developed based upon review of required AMI meter performance parameters. Estimated labor included both employee and contractor costs and incurred through development of the assets listed above. Cost allocation will follow the stated methodology indicated for each AMI asset listed.
- *Project Management.* Estimated labor to support AMI software deployment and includes both employee and contractor costs and incurred through development of the assets listed above. Cost allocation will follow the stated methodology indicated for each AMI asset listed.

B. Cost Allocations to the NSPM Operating Company

As described in the Company's most recent electric rate case, we have protocols to allocate costs to and from the Xcel Energy Operating Companies when projects benefit more than one Operating Company. These protocols are detailed in the Cost Assignment and Allocation Manual (CAAM) and the Service Agreement between Xcel Energy Services Inc. (XES) and NSPM.[16] As noted above, the AMI and FAN initiatives are being implemented across all Xcel Energy Operating Companies.

When a new shared asset software system is in construction work in progress (CWIP), the accumulating charges will be collected under one work order for Xcel Energy Services. Similarly, sometimes an Operating Company will procure a hardware asset that will benefit the other companies. Since the Service Company will not own assets or software, the appropriate percentage of ownership for each participating legal Company would be identified at the time of the initial development of the project.

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[16] See the Direct Testimony of Company witness Mr. Ross L. Baumgarten in Docket No. E002/GR-21-630.

Each Company's share of the cost would be charged to that Company's CWIP monthly while under development and ultimately classified to their own books. Each owner will depreciate their respective share of the asset and as such no allocation is usually necessary. At this time, AMI and FAN are being deployed in Colorado and Minnesota and they are sharing the costs. As additional operating companies benefit from AMI and FAN, costs will also be allocated to them.

Investment in hardware and software for AMI and FAN is currently being made in PSCo to support the system in all Operating Companies. Due to the flexible use of the various hardware components to support AMI and FAN, the Company determined the AMI head-end system will be a shared asset owned by PSCo that will serve the NSP-Minnesota, NSP-Wisconsin, PSCo, and SPS systems. Shared assets are those assets or facilities that are owned by one of the Xcel Energy Operating Companies and used by an Xcel Energy affiliate (e.g., XES or NSPM). This is different from a common or allocated asset, such as the ADMS software, which is developed for multiple companies with the costs allocated accordingly from the outset. PSCo will charge out to the Operating Companies through our standard shared asset allocation process, similar to our 414 Nicollet Headquarters building. A carrying cost on this investment is further allocated to the various Operating Companies. On a monthly basis, the shared asset costs are allocated from PSCo based on the scheduled meter deployments in each Operating Company. It is estimated currently that NSP-Minnesota will comprise approximately 40 percent of Xcel Energy's total AMI meter count and costs will be allocated according to the meter deployment schedule. These are reflected in FERC Account 902 Meter Reading Expenses for purposes of cost recovery through the TCR Rider.

C. Actual and Budgeted Capital and O&M Costs

The Tables below outline the actual costs we have incurred to-date and that are budgeted for the 2022 to 2026 period.

Table 1: AMI Costs – Capital and O&M Actual and 2022-2026 Budget
NSPM Electric (Millions)

	2020	2021	2022	2023	2024	2025	2026	Total
Capital	$4.4	$13.2	$103.0	$143.8	$101.9	$0.0	$0.0	$366.3
O&M	$1.2	$5.9	$12.2	$20.2	$23.7	$15.1	$14.6	$92.9
TOTAL	$5.6	$19.1	$115.2	$164.0	$125.6	$15.1	$14.6	$459.2

Table 2: FAN Costs – Capital and O&M Actual and 2022-2026 Budget
NSPM Electric (Millions)

	2020	2021	2022	2023	2024	2025	2026	Total
Capital	$1.6	$5.9	$9.1	$15.1	$8.6	$0.8	$57.0	$98.1
O&M	$0.2	$1.1	$0.7	$1.2	$0.9	$0.6	$1.7	$6.4
TOTAL	$1.8	$7.0	$9.8	$16.3	$9.5	$1.4	$58.7	$104.5

We provide below an assessment of how these forward-looking AMI and FAN costs compare to estimates we provided in our November 1, 2019 certification request.

Table 3: Variance Analysis – AMI Costs – Capital and O&M
2019 Certification Request Compared to Current Estimates
NSPM Electric (Millions)

	Current Estimate	2019 Certification	Difference
Capital	$366.3	$376.2	($9.9)
O&M	$92.9	$94.8	($1.9)
TOTAL	$459.2	$471.0	($11.8)

In total, the current 5-year budget for AMI is slightly lower than our initial estimates in 2019. We note that at the time we requested certification of AMI, we had not yet finalized contract negotiations with Itron on pricing for the meters, meter installation and project management. Therefore, our current cost estimates will naturally vary based on the final pricing. Our budget now reflects the finalized contractual pricing, and we have at least begun the software development and integration components of the AMI implementation. This work has resulted in further refinements and modifications to our budgets. We also note that the totals presented in our 2019 certification request included the AMI and FAN related costs associated with the TOU/ Flex Pricing Pilot, which for purposes of AMI and FAN infrastructure, is a subset of the mass deployment. The same FAN infrastructure will support AMI in those geographic areas, and our MIV will replace the Pilot meters with the Itron Riva 4.2 meters at no cost for the meter or its installation.

Finally, as noted previously, in our next budget cycle, we will be increasing our AMI budget for the customer-owned equipment work we discussed in Part A above.

Table 4: Variance Analysis – FAN Costs – Capital and O&M
2019 Certification Request Compared to Current Estimates
NSPM Electric (Millions)

	Current Estimate	2019 Certification	Difference
Capital	$98.1	$92.6	$5.5
O&M	$6.4	$8.1	($1.7)
TOTAL	$104.5	$100.7	$3.8

The current overall budget for FAN is also close to the total budget we forecasted at the time of our 2019 certification request. We note however, when the decision was made to use public LTE for FAN backhaul for the foreseeable future while we continue to examine a private enterprise-wide communications network, we shifted the capital that had been budgeted for WiMAX base stations to the outer years of the 5-year budget period. We expect to remove this approximately $60 million contingency placeholder in our next budget cycle, which will significantly reduce the forecasted FAN capital.

VIII. ESTIMATED CUSTOMER RATE IMPACT

Keeping customer bills low is a core strategy of the Company and is a central consideration of our grid modernization efforts and plans. AMI and FAN will provide significant value to our customers and will have an impact on customer bills due to the increased revenue requirement associated with the necessary investments and O&M spending. We performed a long-term rate impact analysis, using a reference case, in conjunction with our 2019 request for certification of AMI and FAN. The overall project costs have not changed significantly from that time, so we provide that same analysis here, which we believe continues to be a reasonable approximation of the incremental cost of AMI and FAN.

To conduct this analysis, we performed a high-level revenue requirement analysis for the five-year budget period to illustrate the incremental revenue requirement and estimated bill impact of AGIS implementation.[17] While we did not perform an exhaustive Class Cost of Service model for this subset of investments and O&M expenses, our analysis provides a reasonable estimate of the annual cost of the AGIS initiative overall, and an estimate of a monthly bill impact for a typical residential customer.

We estimated the bill impact by utilizing a series of allocation assumptions applied to the AGIS costs. Appropriate allocators were applied to distribution capital, distribution O&M, and the remaining costs to develop an estimated residential class revenue requirement. We then divided the estimated residential class revenue requirement by the sales forecast for each year to result in an estimated overall cost per kilowatt hour (kWh). We then calculated an estimated bill impact based the average monthly residential customer usage of 675 kWh. This assessment shows an estimated 2024 bill impact for AMI and FAN of approximately $2.87 per month for an average residential customer. We provide a schedule that details this revenue requirement calculation as Attachment 4G.

We also assessed an alternative investment and costs if the Company did not implement AMI and FAN. As we explained in our 2019 certification request, it is not feasible for the Company to continue to use its current automated meter reading (AMR) meters, because they are nearing end of life and our contract with our service provider for meter reading services and support expires at the end of 2025. As such, we would, at a minimum, need to invest in new meters and provide meter reading services in order to continue to provide electric service to our customers. This means that, even without AMI and FAN implementation, there would be an incremental impact to customers' bills for an alternative metering service.

Therefore, in addition to the AMI and FAN revenue requirement, we developed a reference case scenario to represent an alternative to our AGIS investments. The reference case reflects the necessary investments and costs if the Company were to pursue a basic AMR drive-by meter reading alternative. We calculated the bill impact by using the revenue requirements for the AMR drive-by reference case compared to the AMI and FAN revenue requirement and calculated the estimated bill impact as described above. We provide a schedule that details the reference case revenue requirement as Attachment 4H. This assessment shows an estimated 2024 bill impact

[17] The five-year budget period was 2020-2024. The costs include the AMI and FAN costs associated with the certified Residential TOU pilot.

for the AMR drive-by alternative of approximately $1.51 per month for an average residential customer.

The key comparison and impact is the difference between the estimated bill impact of AMI and FAN implementation versus the basic alternative, as shown below.

Table 5: Illustrative Monthly Bill Impact – Typical Residential Customer using 675 kWh
(2020-2024 Period)

	Year 1	Year 2	Year 3	Year 4	Year 5
AMI and FAN	$0.44	$1.33	$1.84	$2.58	$2.87
Reference Case	$.01	$0.19	$0.62	$1.18	$1.51
Difference	***$0.43***	***$1.14***	***$1.22***	***$1.40***	***$1.36***

This Table illustrates the incremental bill impact of pursuing AMI and FAN compared to the investments that would otherwise be necessary. In other words, the difference reflects the costs that will enable all the benefits of the advanced grid, both quantifiable and non-quantifiable, that AMR meters simply will not provide. Additionally, this illustration shows that costs of AMI and FAN will be spread over the implementation period, which reasonably manages the bill impact for our customers. For the estimated actual rate impacts of the investments included in our overall TCR petition, see Section VII of the TCR Petition, which includes a discussion regarding the class allocation methods for the distribution and transmission components and the estimated bill impact for an average residential customer.

IX. COST BENEFIT ANALYSIS

As part of our 2019 certification request, we conducted a cost-benefit analysis (CBA) for the AMI and FAN initiatives. At that time, we assigned a (majority) portion of FAN costs to AMI and the balance of FAN costs to the other AGIS technologies we were proposing at that time. Because the Commission only certified AMI and FAN, we updated the CBA to reflect that outcome, assigning all FAN costs to AMI – See Attachment 4A. In this TCR proceeding, we also have updated the CBA using updated budget information and assumptions, including the longer life of the AMI asset that was an outcome of the remaining lives proceeding in Docket No. E,G002/D-20-635.[18]

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[18] *See* Order Point 4 of the Commission's March 24, 2021 Order in Docket No. E,G002/D-20-635.

We also note that, while we utilize CBAs as one tool to assess larger projects, it is important to be cognizant of the limits of a CBA. A cost-benefit model cannot capture benefits that cannot be quantified, such as public policy goals, opportunities for future customer benefits, customer satisfaction, power quality, improved safety, and similar improvements. As a result, a CBA does not provide a complete picture of the costs and benefits of any given program. Those modeling limitations become even more pronounced where, as here, a large portion of the costs of the AGIS initiative are unavoidable because they are associated with addressing aging metering assets that are central to core utility functioning. Further, as we also explained in our 2019 certification request, the FAN in and of itself, does not provide direct benefits to customers or the Company. Benefits to customers and the distribution system will be realized through FAN's support of, and interaction with, other programs and technologies. We therefore focus the benefits discussion on AMI.

A. Summary CBA Results

The CBA quantifies the costs and benefits from a customer point of reference. Costs are calculated as a revenue requirement and only benefits that the customer realizes are included. As we noted, this CBA is a refreshed version of the CBA that we submitted in 2019 with our AMI and FAN certification request. The primary drivers that affected the CBA ratio in this refreshed version are that 100 percent of FAN costs are now assigned to AMI, and the AMI useful life was extended from 15 to 20 years. The updated CBA result indicates that the quantifiable costs and benefits of AMI and FAN total 1.01 in our baseline scenario or 1.33 under a high benefit/no contingency scenario. From a customer perspective, the benefits exceed the costs for the 20-year life of the meter.[19]

[19] This is a change from the CBA ratio for AMI in our 2019 certification request. In that case, the ratio was 0.83 under the baseline scenario and 0.99 under the high benefit/no contingency scenario.

Table 6: NSPM AMI Benefit-to-Cost Ratio (Millions)

NSPM-AMI-NPV	Total
Benefits	$557
O&M Benefits	$68
Other Benefits	$284
CAP Benefits	$205
Costs	$(553)
O&M Expense	$(148)
Change in Revenue Requirements	$(405)
Benefit/Cost Ratio	**1.01**
Benefit/Cost Ratio (no contingencies)	**1.33**

Not included in this ratio, are tangible, additional *qualitative* benefits such as customer satisfaction and operational, power quality, and safety enhancements. Furthermore, AMI is an initiative that replaces a fundamental component of our provision of regulated utility service (AMR) that is approaching end of life as we described in detail in our 2019 certification request, as well as adding capabilities and services for our customers and enabling future customer- and grid-facing products, services, and technologies.

In the remainder of this section, we summarize the benefits that we considered as part of our analysis, then discuss the quantitative benefits that are part of our CBA and specific qualitative benefits we also considered.

B. Benefits Summary

The four categories of benefits that we expect from implementation of AMI are unchanged from our 2019 certification request: (1) quantifiable capital benefits, (2) quantifiable O&M benefits, (3) other quantifiable benefits, and (4) non-quantifiable benefits. The quantifiable benefits of AMI are in the CBA model that calculates a benefit-to-cost ratio for the AMI and FAN implementation.

Table 7: AMI Capital Benefits

Benefit	Description
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system.
Outage Management Efficiency	Improved capital spend efficiency during outage events.
Avoided Meter Purchases	AMI meters have a lower failure rate as compared to AMR meters. By purchasing new AMI meters, the Company avoids the need to replace failing AMR meters.
Avoided investment of an alternative meter reading system	Avoided capital cost of a drive-by meter reading system, instead of the AMI investment, since current Cellnet system requires replacement

Table 8: AMI O&M Benefits

Benefit	Description
Avoided O&M Meter Reading Cost	O&M cost component of a drive-by meter reading system alternative to AMI, since current Cellnet system requires replacement
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs.
Outage Management Efficiency	Improved O&M efficiency during outage events.

Table 9: Other AMI Benefits

Benefit	Description
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.
Reduced Consumption Inactive Premises	Expedited ability to turn off power quickly when determined premises have been vacated.
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible/bad debt.
Reduced Outage Duration	Direct benefit to customers associated with reduced outage duration
Critical Peak Pricing	Customer demand savings in response to new rate structures.
TOU Customer Price Signals	Difference in energy prices paid by consumers in response to new rate structures.
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to shifted load.

We note that there is a relationship between when benefits will start to be realized when we begin our AMI meter deployment and when back-office functionality is enabled via data processing, management, and integration with other systems. In general, most benefits will be fully realized upon the completion of our meter deployment in 2024. Partial benefits will begin to be realized in the 2023 timeframe.

Finally, we note that while the FAN does not have direct benefits for customers, one tangible benefit of the FAN communication network is its support of the deployment of AMI meters. As we discussed in our 2019 certification request, deploying new meters without the FAN would be considerably more expensive to install and operate because the Company would need to find other ways read data from the meters, such as driving by or physically reading them – both of which would require truck rolls and added labor costs. Other advantages of the FAN coupled with AMI as we have also otherwise discussed, are enabling the ability to send remote commands to the meter (such as connect/ disconnect), and reading data as often as required without dispatching a truck and personnel to do so. The reliable, secure network capabilities provided by the FAN also enable the end-to-end transport of interval meter data to provide the significant customer and grid benefits enabled by AMI.

Ultimately these capabilities will similarly enable other technologies as the Company further implements its grid modernization strategy that also helps to transform the customer experience and create additional customer value. For example, enabling DI at the meter for increased customer value, the FAN will also support the ability to deploy computing capability closer to field devices (for example, in substations) that will allow for quicker identification of potential issues and immediate resolution. This deployment will enable the Company to monitor and manage impacts of DER (for example, solar resources) and other events occurring on the grid in a more-timely manner.

Based on these benefits, and the inputs we updated, the refreshed CBA we performed indicates that the quantifiable costs and benefits of the AMI and FAN initiative total 1.01 in our baseline scenario, or 1.33 under a high benefit/no contingency scenario.

Below, we discuss in more detail the quantitative factors considered in the CBA, as well as the qualitative benefits supported by AMI and FAN, such as customer satisfaction and certain operational and power quality improvements, as well as safety enhancements.

C. Quantitative Benefits

1. Distribution System Management Efficiency

AMI will provide the Company with information about the connectivity and workings of the distribution system. AMI data can be aggregated at varying levels of the distribution system including tap, transformer, and service lines amongst other distribution system equipment. The Company will be able to use this information to prioritize distribution grid improvements and more efficiently plan and design the system, for example, to determine optimal timing for installation and replacement of distribution assets as well as optimize inventory levels. Through the aggregated AMI data, we will have greater insights into the nature of the load – specifically load profiles, which will help us evaluate risk. The voltage insights will help us prioritize areas for investments in tap, transformer, and secondary wire replacement. For instance, the AMI data can be aggregated at the transformer level to identify overloaded transformers as well as determining the optimal transformer for replacement transformers. We will also have tools to better understand system losses which will help us evaluate opportunities for investment to minimize these losses. We have estimated that AMI meters will provide a one percent reduction in capital and O&M expenditures for Asset Health and Reliability projects and Capacity projects.

2. Outage Management Efficiency

AMI will enable increased outage management efficiencies by providing automated outage notification and restoration confirmation (power-on information) to the Company's Outage Management System (OMS). AMI meters send a "last gasp" message to the utility before the meter loses power. While not all "last gasp" messages make it, usually enough messages are received to help the utility adequately determine which customers are affected. Outage notification from the AMI meters will provide the Company with a timelier and more accurate scope of an outage, which will then assist the Company in restoring power more quickly by allowing the Company to deploy crews more efficiently to outage areas, especially during storm outages. Another benefit of AMI meters is verification of power restoration after an outage. Restoration verification is accomplished when a meter reports in after being reenergized. This will provide automated and positive verification that power has been restored to all customers, there are no nested outages, and all associated trouble orders are closed before restoration crews leave the areas. These efficiencies reduce the time and expense in locating, scoping, and responding to an outage, and increases customer satisfaction through quicker response and restoration to customer outages – also minimizing inconvenience or economic losses experienced by the customer. We note that we anticipate this to become most effective when ADMS and AMI are fully integrated with OMS.

3. Avoided Meter Purchases

We anticipate AMI meters will have a lower failure rate than our existing AMR meters, because they are newer. As a result, there is a cost savings associated with not having to replace as many failed meters. The benefit from avoided AMR meter purchases, however, is partially offset by the cost of ongoing replacement of AMI meters due to normal failure rates.

4. Avoided Cost of Alternative Meter Reading System

As we have explained, our current meter reading contract is set to expire in 2025 (or 2026 with a costly extension), yet the Company will need to continue to read customer meters as part of its core utility operations. One option is to replace the current AMR Cellnet meter reading system with another basic AMR meter reading alternative such as a drive-by system. Since the deployment of AMI will eliminate the need to replace the existing AMR Cellnet meter reading with an alternative drive-by meter reading system, these avoided costs are a benefit of AMI. Like we did in our assessment of customer rate impacts, we used this as a reference case in our CBA – modeling the estimated costs for the life cycle of an alternative AMR meter system.

5. Reduced Field and Meter O&M Expenses

Since AMI meters will have the ability to provide billing, power, and voltage information to the Company on command, there will be a reduced need to send personnel to the field to gather this information. This will result in O&M savings in several areas:

- *Reduction in Outage Trips due to Customer Equipment Damage:* Our current AMR system requires crews to be dispatched to verify outages. Sometimes these outages are due to damaged customer equipment and not utility damaged equipment. Under the new AMI system, AMI meters will have two-way communications to the meter and the Company can verify whether there is power at the meter thus pointing to a likely customer problem. This will help reduce field trips while also assisting customers in identifying the likely cause of the outage.
- *Cost Savings from Remote Connect Capability:* AMI enables remote connection and disconnection of residential type service without the need to dispatch crews. This will result in personnel and transportation cost savings due to the reduction in field visits.
- *Reduction in "Ok on Arrival" Outage Field Visits:* AMI will allow the Company to test for loss of voltage at the service point and detect both outage conditions and to know when restoration is complete. As a result, AMI implementation will help eliminate unnecessary field trips to customer premises that result in field personnel finding no electric service issues upon arrival.
- *Reduction in Field Visits for Voltage Investigations:* When notified of a potential voltage problem, the Company currently sends a technician to investigate. AMI enables the elimination of unnecessary trips when proper voltage can be verified remotely, and helps us prioritize and dispatch the most appropriate crews if the voltage is outside of the appropriate range.

6. Reduced Consumption on Inactive Meters and reduced Uncollectible/Bad Debt Expense

AMI provides the ability to disconnect to prevent usage on accounts that have had a stoppage of service. Included is the assumption that tenants cannot be disconnected during cold weather protection timeframes. This is ultimately a cost savings, reducing usage on unassigned accounts. Remote disconnect of AMI meters prevents additional usage on accounts that are overdue – reducing bad debt write-off. We discuss our plans for use of the remote switch in the meters in Section III.B.2.

7. Reduced Theft/Meter Tampering

Data retrieved from AMI meters allows for analytics to be used to identify tampering and theft of meters.

8. Load Flexibility Benefits (Critical Peak Pricing and Time of Use Rates)

The Company engaged The Brattle Group (Brattle) to model likely customer response to Time of Use (TOU) and Critical Peak Pricing (CPP) rates. The Brattle Group produced a study entitled "The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory" (the Brattle Study). The Brattle Study developed quantification of the benefits of potential TOU and CPP rates, incorporated into our CBA. Further, the Company utilized information about shifting demand from on-peak to off-peak periods, resulting in energy price savings for customers and carbon reduction benefits.

- *TOU Customer Energy Price Savings:* Demand reduction grows modestly as TOU adoption and utilization expands. Based on these assumptions and the base case in the Brattle Study, this rate has the potential to shift demand approximately 160 Megawatts (MW) for evidential customers and 50 MW for medium commercial and industrial customers from on-peak to off-peak. The overall result is cost savings to most customers.
- *TOU Reduced Emission:* The shift from off-peak to on-peak provides reduced emissions estimated at approximately 4,500 CO_2 tons annually.
- *CPP Benefits:* A potential CPP rate would provide customers with a much higher rate during peak hours on 10 to 15 days per year. Brattle modeled a CPP rate as being offered on both an opt-in and an opt-out (default) basis, with demand reduction growing modestly as the system and system usage mature. Load flexibility rates such as this one have the potential to reduce peak demand at the generator level by approximately 165 MW for residential customers and 90 MW for medium commercial and industrial customers.

We outlined our roadmap for TOU and other advanced rate designs in an October 1, 2020 filing in Docket No. E002/M-19-666. For purposes of this CBA, we are assuming a realization of CPP and TOU benefits in 2024 and beyond.

D. Qualitative Benefits

It is difficult to put a numeric value on future opportunity and non-monetary benefits, so evaluating qualitative benefits can be challenging – however, consideration of qualitative benefits are very important when assessing a project's value. Trends in the utility industry, efforts of other states to advance distribution grids, and industry-wide resources like the Department of Energy's Smart Grid effort, validate the importance of bringing utilities' distribution grids into the future. Without AMI and FAN, the Company will soon be behind in managing customer expectations, supporting DER, employing future technologies, maintaining reliability goals and expectations, and fully capturing demand side management opportunities. AMI and FAN are therefore fundamental parts of the Company's strategic plans to meet and exceed customer expectations as well as a standalone requirement for a robust and resilient distribution grid.

That said, the non-quantifiable benefits of advancing the distribution grid are difficult to overstate. Safety, reliability, and customer satisfaction are vital to our role as a public utility. A few examples include:

- Improved customer choice and experience, leading to customer empowerment and satisfaction,
- Enhanced DER integration,
- Environmental benefits of enhanced energy efficiency,
- Improved safety to both customers and Company employees, and
- Improvements in power quality.

Each of these are enhanced by our AMI implementation. A more automated, insightful, and transparent grid supports greater customer empowerment and safety as well as continuing quality system average interruption duration index (SAIDI) and system average interruption frequency index (SAIFI) measurements, along with improved ability to measure momentary average interruption frequency index (MAIFI). Additionally, AMI is important to the Company keeping up with greater customer demand for DER.

1. *Customer Empowerment*

Giving customers choice and control over their energy usage by providing them with greater insight; greater input into the types of energy they use by supporting DER, and empowerment to make good choices about their impact on the environment are all important elements of both building customer satisfaction and managing electric demand.

Most importantly, there are simply limitations to our current system that frustrate customers and cannot be resolved without aspects of the AGIS initiative. In many cases, without AMI metering technology we have limited ability to identify outages without relying on the customer. Additional grid modernization initiatives that build on AMI and FAN will allow us to improve reliability by automating fault response and identifying more issues beyond the substation through DA technologies such as FLISR. Two-way communication and additional devices will allow us to enhance voltage optimization and better support DER. This further allows us to look to the future, and to emerging capabilities like DI, more customer application and interface technology, and additional energy sources through a modernized distribution grid. These benefits relate largely to customer satisfaction and future-proofing the distribution grid – benefits that are difficult or impossible to quantify.

Empowering customer choice is a key driver of our grid modernization strategy. Digital metering and technologies enable new programs and tools for customers that give them more power over their energy usage. Some of these options, such as the opportunities to receive regular updates about their electricity usage and to tailor their electric usage to reduce their electricity costs, are discussed above. But customer choice goes beyond TOU rates or remote connect/disconnect options.

With AMI, we have the option to implement customer-opted budgeting tools and high usage alerts that notify customers if they exceed or approach certain thresholds; to create internet portals that provide greater insight into energy consumption and peak demand; and to develop mobile apps that allow near real-time information access. AMI will also support the two-way flow of energy via net metering, further supporting customers' abilities to invest in DER options such as rooftop solar and potential energy storage or battery options, if they should choose to do so.

2. Power Quality Improvements

AMI will provide more timely and granular data on the flow of energy to and from our customers. With this load flow information, and with voltage, current, and power quality data provided from AMI to ADMS, system operators will be able to facilitate the integration of greater amounts of distributed generation on to the system. In addition, the bi-directional capabilities of the AMI meters will allow the ability to perform net metering for our DER customers without the need to change out the existing meter.

Additionally, the AMI system will capture voltage and usage data that can be compared with nameplate or operational limits of our equipment. Using this data, we will be able to identify problems such as solar causing high secondary voltage, or transformer overload due to either a strong presence of EVs (load) or high reverse flows (such as solar generation). It is our intention to leverage AMI data for this purpose, which will allow us to better facilitate the interconnection of DER, while at the same time maintain reliability and power quality for all of our customers.

3. DER Integration

AMI will enable the creation of more accurate load profiles that are used by ADMS to create better system models for planning and operational purposes. Initially, ADMS will be using relatively few profiles to represent typical customer loads. Once AMI has been in place for a year, we will be able to create more refined profiles, which will significantly improve our models that are available not only to ADMS – but rather all of our systems and processes that rely on our Geospatial Information System (GIS). This data will then support planning and operational modeling, enabling us to more accurately identify problems (or the lack thereof) as more load or DER hosting is contemplated for the system.

Finally, AMI meters have bi-directional capabilities that can be utilized by our DER net-metering customers. Currently, when a customer who is eligible for net-metering adds generation, we replace the meter to enable bi-directional flow. With AMI, we will be able to effect this change remotely saving the cost of a meter change.

4. Energy Efficiency

AMI is expected to result in greater energy efficiency by customers and the Company. As previously noted, AMI will provide the customer more information on energy usage and will enable the Company to offer additional time-based rates or other offerings that allow more customer choice in controlling their energy usage and costs. To the extent these energy efficiency gains reduce the need for generation they will contribute to lower energy emissions.

5. Safety Improvements

AMI enables the meters to be read, remotely disconnected and reconnected, and enables remote diagnostics of the customer's service, thereby minimizing safety risks for Company representatives and the customer. For example, AMI will allow us to more rapidly assist emergency personnel by remotely shutting off power to a burning building as opposed to dispatching a truck to perform the disconnection. In addition, while AMR meters can do some level of automated reading, they cannot minimize meter diagnostic and connect/disconnect visits to the same extent as AMI meters. AMI provides several remote functions that eliminate or minimize the need for the Company to visit the meter, which minimizes the intrusiveness to the customer and potentially reduces safety concerns of unknown people accessing their property. Reducing these visits also reduces employee safety risks associated with customer pets and traversing unfamiliar properties.

6. Power Quality Improvements

AMI will monitor and provide power measurement and voltage data at more points within the distribution system, which will be used in load flow calculations to enable improvements in power quality. This will help ensure voltage is within acceptable limits from the substation all the way to the customer's point of service. In other words, better monitoring of power quality reduces the potential for out-of-range voltages that may interfere with electronic devices in customers' homes or businesses. Additionally, timely power outage and restoration will enable improved outage management and contribute to improved power quality to our customers overall.

E. Summary

The AMI and FAN initiatives are a key part of a broader strategic vision that directly aligns with the Company's strategic goals to lead the clean energy transition, enhance the customer experience, and keep customer bills low. Our goal with AMI and FAN implementation is to use new technologies to transform the customer experience, to meet the increasing customer demands for additional energy usage data, as well as new products and services that will provide opportunities for customers to use that information to control usage.

With AMI and FAN, we are replacing fundamental components of our system that are approaching end of life, and adding capabilities for our customers now (and in the future) to address a future that includes greater DER, DI, and greater customer engagement. The CBA, which is limited to measuring the difference between costs and quantifiable benefits does not tell the full story. We believe the total value of these initiatives significantly outpaces the cost of the investments, and that the AMI and FAN investments are prudent and needed to serve customers now and into the future.

X. IMPLEMENTATION

To support the Residential TOU Pilot, we deployed approximately 17,500 AMI meters to pilot customer locations and limited FAN infrastructure in 2019 in the small geographic area overlaying the AMI meter deployment (Eden Prairie and Minneapolis).[20] For any given geography, FAN availability will precede AMI meter deployment by approximately 3-6 months, to ensure that meters will have a fully operational network to use when they are installed. To support this, we intend to begin FAN installation approximately 12-18 months ahead of AMI meter deployment to allow adequate time for permitting, material sourcing, and construction. Based on the current schedule for the full AMI meter deployment, FAN deployment began in mid-2021 to ensure network readiness for when AMI meters are installed. As of November 5, 2021, 131 of the 201 FAN network devices required for 2022 meter installations have been installed.

A. AMI and FAN Deployment

The deployment of AMI has three components: (1) Meter Deployment, (2) Software Development, and (3) FAN Deployment. We have already completed limited AMI implementation in connection with the TOU/ Flex Pricing Pilot in Minnesota, and completed initial work for full AMI rollout in our Public Service Company of Colorado (PSCo) affiliate. Full AMI implementation in Minnesota will expand on and enhance these capabilities to meet requirements for deployment in Minnesota. In this

[20] Additionally, the original 17,500 TOU meters deployed in 2019 and early 2020 to support the residential Flex Pricing pilot, will be replaced during the mass rollout with the new AMI meters at no cost to the Company as a result of our negotiations with our AMI meter vendor. This includes the cost of the AMI meter and labor for replacing these meters.

section, we outline our preparations and plans for mass meter deployment in Minnesota.

1. *Meter Deployment*

The Company plans to deploy approximately 1.4 million advanced meters in Minnesota. Meter deployment includes AMI hardware evaluation, testing, acquisition, configuration, and deployment of electric meter assets. In this section, we discuss the high-level schedule and our testing and other implementation-related plans and activities.

a. Mass Deployment and Testing Timeline

In 2018, the Company issued an RFP to meter manufacturers, specifying accuracy, data and functionality requirements, and communications compatibility with the selected AMI communication network. An AMI meter contract was signed in August 2019. Because of the timeline required to have such AMI meters available, the Company shifted out the start of mass deployment from the original start of 2021. We now expect to start mass deployment in early 2022 through 2024, as outlined below.[21]

Table 10: AMI Meter Mass Rollout Schedule (Service Points)

Year	Meters Installed
2022	450,000
2023	590,000
2024	360,000

In 2020, we started testing the AMI meters with DI capabilities, focusing on electric distribution and customer operational requirements. Testing included First Article Testing of the meter accuracy, and evaluation of data sets from the meter through the meter reading and billing systems. First Article Testing is performed on meters containing the Company's requested programs and configurations, to ensure they meet all specifications as required by the Company. We then performed Integration Testing that examines business requirements and functionality across all products, applications, and platforms involved in the implementation of AMI, from meter to bill. The purpose of Integration Testing is to confirm that changes made within

[21] We note that our AMI deployment is affected by the global supply chain issues associated with computer chips, so these deployment volumes are subject to change.

individual applications work correctly when tested together with changes made in other applications, ensuring data quality and accuracy across all systems in scope for AMI. We are continuing to coordinate closely with Itron in planning for meter testing and deliveries to meet our deployment schedule.

b. Plan to Address Customer-Related Equipment Issues

As also noted in Section VII in relation to development of the project budgets, as part of our AMI deployment and installation plans, we expect we will find that a limited number of customer meter sockets are defective and do not comply with Xcel Energy's standards and criteria applicable to meter sockets as set forth in Section 4.11 of Xcel Energy's Standard for Electric Installation and Use (Xcel Energy Standards). Section 4.11 of the Xcel Energy Standards designates meter sockets as customer-owned equipment, which means that customers are responsible for its maintenance and repair. However, to ensure a timely and efficient roll-out of the Company's new AMI meters, we plan to facilitate any necessary minor repairs on the customer's behalf and at the Company's expense. We will coordinate with the customers to complete these repairs at a mutually agreeable time, and require each customer to sign a consent and release form, which we provide as Attachment 4I. We will not, however, perform work beyond the meter housing and socket; should that work be necessary, the customer will need to hire and pay for a qualified electrician to perform that work. If a customer refuses to sign the consent and release for the Company to facilitate the necessary repairs, the customer will need to hire a qualified electrician to complete the necessary repairs at their own cost – and will not receive an AMI meter until that work is complete. As noted in Section VII, our current budgets do not include the costs for this work on customer-owned equipment; we will be adding it to our AMI project budget in our next budget cycle.

2. Software Development

The Company is integrating AMI, as well as other AGIS systems and related data, with the Company's existing applications. Specifically, Company has implemented new AMI head-end software that has been installed and configured to run on new server hardware. From the AMI head-end, interfaces have been built to transfer the data to other applications, such as the billing and customer service system. This integration work allows the Company's existing infrastructure to "speak with" the new infrastructure being implemented pursuant to the AGIS initiative. The phases of software development include:

- Analysis and Requirements

- Design
- Build
- Testing

In 2019, the Company completed work on the integration, testing, and deployment for the head-end to support reading, monitoring, and controlling the AMI meters. All required initial interfaces for communications and billing support have been validated to be able to enter the Meter Validation Test Phase. Successful 2019 software deployments also provided the baseline functionality required for subsequent software solution capabilities delivered in 2020 and 2021. The work necessary to implement the required AMI functionalities began in the fourth quarter of 2018.

The software solutions delivered in 2020 and 2021 consisted of the following functionalities:

- *Meter Data Management (MDM).* The selection of the MDM was completed in Q4 2019. The selection process involved multiple candidate vendors and numerous architectural options, before coming to the most logical and cost-efficient conclusion for the AGIS Project and the Company's customers.
- *Interval Billing Functionality.* Software delivery work has been initiated to transition to interval billing capability. Historically, customer billing has been based on billing "registers."[22] Interval Billing provides more flexibility and control for the customer Billing options. Included in this ongoing work is the set up of NSPM rate configurations in both new AMI services and the integrated legacy systems to support interval billing functionality for different customer types using AMI meter data ahead of meter deployment schedules; we have a delivery team focused on this collective work product for all OpCos which we have named the "Rate Factory" team.
- *Meter Installation Vendor (MIV) Integration.* Contract Negotiations for the Mass Deployment Meter Installation Vendor for the Company were completed in the third quarter of 2019. Integration of Company and MIV systems will allow the MIV to receive installation orders from the Company, complete the orders using their field tools, and send the results of the order to the Company.

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[22] This change in billing basis also required a variance in the Commission's Billing Content rules, as discussed in Part XI.B below.

- *Reporting.* Reporting is an ongoing requirement throughout the AGIS program activities. A select subset of reports based on business requirements is identified and delivered each year in software releases.
- *Over the Air.* Software services to enable meter programming, updates to network equipment, and firmware updates to field device capability (over the air) was initially delivered in 2021.
- *Customer Care.* Delivering near real-time AMI data access for employees that support customers had first features delivered in 2021, with a second release planned in 2022 to support additional data presentment.
- *My Account.* The capability to deliver meter usage information to our customers, was initially delivered in 2021 for residential customers. Additional releases are planned in 2022 to support meter usage presentment for other customer types.
- *Meter Data Lake.* The Company has established a scalable Meter Data Lake as a platform to consolidate meter data and support use cases around data sharing and analytics. The Meter Data Lake provides a centralized processing and data distribution repository for meter interval data, and event data to support analytics and efficient data distribution.

3. FAN Deployment

The FAN implementation includes the planning and studies to determine where the WiSUN and network devices shall be located geographically (generally on distribution poles) to establish network reliability and optimum operation of the network once fully deployed. The devices are then installed at the specified locations by Distribution field crews. Once the devices are installed, they are tested and monitored by the Network Operations Center (NOC) to ensure they are operating as expected. As stated above, FAN deployment for the mass AMI implementation began in 2021, with 131 FAN devices installed as of November 5, 2021.

The FAN deployment, up to and including full testing and monitoring by the NOC, is completed six months in advance of any meter deployed in that geographical area. As such, a roll-out deployment of FAN devices and connectivity is based on the deployment schedule provided by the meter deployment team and based on “blocks” of meters in a specific geographical area.

As soon as the network devices are deployed and being monitored by the network, any performance degradation or loss of connectivity with any AP or repeater is flagged and a trouble ticket is created for resolution. Once meters are deployed, the system provides daily reports on AP performance and read rate percentages of each AP to identify and report on any devices that are not performing at 100 percent. When a device (AP) fails, the network "heals" itself by rerouting traffic thru other healthy APs to ensure reliability and continued network performance. Once meters are deployed, this health of the system will be reported on a daily basis to support groups and leadership.

B. Internal Preparations

AMI will fundamentally change the way that we bill our customers, our meter data and processes, the way that data flows, and our information systems interface with each other. We also know from AMI implementations that have preceded ours that some customers will not want a "smart" meter. Therefore, soon after the Commission certified AMI and FAN, we sought approval of changes that would implicate existing Commission Rules and our Tariffs, so that those outcomes could be integrated into our other information system and process work that precedes the actual AMI implementation with customers.

1. Rule Variances and Changes to our Tariffs

In July 2020, we submitted a petition seeking a variance to the Commission's Rules for customer bill content and an addition to our Tariffs for an opt-out option for customers who do not want an AMI meter.[23] We summarize each of these requests and the Commission's decision below.

a. Variance to Billing Content Rule Requirements.

With AMI, customer billing will be based on individual usage intervals rather than measuring the difference between the previous and current meter readings as we do today. Minn. R. 7820.3500 governs the content of customer bills and requires utilities to present customers with, among other things, their present and last preceding meter readings on each bill. Because these values will not be relevant to the calculation of customers' bills upon receiving an AMI meter, we sought a variance from this Rule to no longer print this information on customers' bills. This change also required a

[23] *See* Xcel Energy Petition, Docket No. .E002/M-20-592 (July 10, 2020).

change to the Standard Bill Forms contained in our Electric Rate Book. The Commission approved our proposed standard bill form with a modification that required that the billing interval be provided on the bill; the Commission also required the Company to work with its Consumer Affairs Office (CAO) on the AMI-related deployment customer communications.[24]

b. Customer Opt-Out Option

With AMI, we expect some customers will want to opt-out of an AMI meter that will communicate usage and other information over the FAN. Because the non-standard/opt-out meters will not have the radio capabilities to communicate over the FAN, we will need to manually gather customer usage for billing purposes. We propose to add an optional Manual Meter Reading (MMR) tariff to our Electric Rate Book for customers who opt-out of AMI that outlines the framework, parameters, and associated customer costs, which we have developed based on the principle of cost causation. In summary, customers will be able to make an opt-out decision either during the initial AMI deployment, or after the standard AMI meters are installed. Our Petition sought approval of proposed terms, conditions and the customer charge methodology – with the specific charges to be calculated and submitted to the Commission after the cost of the non-standard meter is known and closer in time to the start of our actual AMI implementation. The Commission approved our proposed tariff with some future reporting requirements.[25]

The Commission's Order also requires that we provide various information in future cost recovery requests related to this service. Specifically, the Order requires the Company to provide an update on the selected Mobile Meter Reading (MMR) (or non-standard) meter and updated cost estimates and tariff sheets in any future cost recovery request that reflects the final cost differential of the non-standard meter. It also requires the Company to file estimated and actual revenue information in any

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[24] *See* July 21, 2021 Order in Docket No. E002/M-20-59 at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={204AC97A-0000-CA12-AB81-52A2D3DB2985}&documentTitle=20217-176351-01. See the Company's Compliance Filing with its Tariffs reflecting the approved changes at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={F04F797B-0000-CE1C-86D2-E4D54D30D696}&documentTitle=20218-177399-01. And, see the Company's Compliance Filing containing its final Customer Education and Communication Plan and materials at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10C3137C-0000-C81E-A89E-D55E52536131}&documentTitle=20219-178195-01

[25] *Id*

upcoming cost-recovery requests for AMI and FAN. And finally, it requires the Company to exclude its AMI cost recovery from its next rate case if the company requests cost recovery through its next Transmission Cost Recovery Rider Petition.[26]

First, we confirm that we are only seeking cost recovery for AMI and FAN in this TCR proceeding, as explained in our MYRP filed October 25, 2021 in Docket No. E002/GR-20-630 and as part of this filing. We addressed our understanding of the remaining cost recovery-related requirements in our June 11, 2021 Supplemental Comments – and neither are implicated by this TCR request for AMI and FAN cost recovery.[27] Namely, we clarified our understanding that we already provided the final cost of the non-standard meters in our 30-day compliance filing – and the intent for the estimated and actual revenue information is that we would provide that as part of the formal review of the MMR service within one full year of AMI implementation – and, we would only need to include it in a future cost recovery request if the cost components of the MMR service are implicated. Neither of these are implicated in this TCR proceeding, so we do not provide any updated financial information about this optional service with this AMI and FAN cost recovery proposal.

2. *Information Systems Integrations – AMI*

a. AMI Head-End

The AMI meters must be integrated with the Company's IT systems. AMI is data intensive, including meter readings, energy usage interval profiles, power outage and restoration events, power quality information and other data transmitted and collected frequently. All data traffic between the Company's systems and AMI meters is transmitted via the AMI head-end application and, depending on the data, must be integrated and made available to the applicable business system in an accurate and timely manner.

The Company has already installed the AMI software head-end for use in Colorado and for the Minnesota TOU Pilot. This same software is being used and expanded

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[26] *See* Order Point Nos. 7, 8, 9 in the Commission's July 21, 2021 Order in Docket No. E002/M-20-592 at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={204AC97A-0000-CA12-AB81-52A2D3DB2985}&documentTitle=20217-176351-01

[27] At the time, the requirements were Department recommendations that ultimately lead to the Order Points; at the hearing, the Commission acknowledged that we had clarified our understanding of them in our comments. *See* Xcel Energy Supplemental Reply Comments, Docket No. E002/M-20-592 (June 11, 2021) at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={9091FC79-0000-CF1D-AF39-E3F79584F632}&documentTitle=20216-174998-01

upon in Minnesota for full roll-out. Many of the integrations already built in Colorado will be leveraged in Minnesota, and any newly required interfaces with legacy systems have been identified and are being developed as required to meet unique state needs. Major systems integrations include but are not limited to:

- ADMS
- Customer Resource System (CRS)
- Systems, Applications, and Products (SAP)
- Field Deployment Manager (FDM)
- Meter Installation Vendor
- Network Management System (NMS or OMS)
- Distributed Intelligence (DI)
- Meter Asset Lifecycle Management System
- Meter Data Management (MDM)
- Customer portal and new initiatives
- FAN

In addition, these applications will share data with other applications, such as the Company's Data Warehouse, as well as any new operational reporting solutions.

b. ADMS

ADMS provides an integrated operating and decision software support system to assist control room, field personnel, and engineers with the monitoring, control and optimization of the electric distribution system. ADMS utilizes AMI data to deliver potential advanced grid capabilities such as FLISR. AMI deployment provides the ADMS with timely real and reactive power measurement data that can be used in load flow AD management calculations. AMI meters will also provide voltage measurements at various points on the distribution system. This is an enterprise-wide integration that will be used or significantly enhanced, as necessary, to support Minnesota requirements.

c. Customer Resource System (CRS)

CRS is our customer system of record. It provides capabilities for customer service, billing, service orders, and payments. CRS is currently integrated with the Meter Asset Lifecycle Management System (MALMS) and Meter Data Management (MDM) System. AMI head-end integration with the CRS will allow the Company to streamline multiple processes. As an example of a process improvement resulting from integrating the AMI head-end with the CRS, we will be able to obtain a meter reading to begin or end a billing cycle when a customer moves into or out of a premise without a visit to the customer premises. As another example, when a disconnected customer pays their bill, an order generated in the CRS can be sent to the AMI head-end to automatically (and more quickly) reconnect the service. Disconnect and reconnect processes today are manual processes that require a person to physically visit the customer's site; while we would need to make a filing with the Commission to ensure permissions to utilize remote disconnect, these capabilities are available. This is an enterprise-wide integration that will be used or significantly enhanced, as necessary, to support Minnesota requirements.

d. SAP

SAP manages the general ledger and work and asset management activities across the Xcel Energy enterprise, which were implemented between 2015 and 2017. SAP is an Xcel Energy-wide platform with financial management and asset management capabilities throughout the enterprise. As a result, two-way integration is required to support business processes for the Company personnel and customers. Through SAP, customer or field operations work orders initiated from service orders are scheduled, dispatched, and updated. These updates provide information that is synchronized back to the service order/process tracking jobs in CRS so that up-to-date information related to work orders is available to representatives and customers. Grid information is being integrated with SAP across the enterprise, including to support Minnesota requirements.

e. FDM

The Field Deployment Manager is a new application that supports the field technicians work and meter communication with the advanced meters. FDM accepts meter reading requests from a customer system, converts and uses the data to load handhelds with assignments to be processed during this cycle, uploads the handhelds when the meter reader has completed the route, updates the route data file, produces reports and performance tracking, and supplies meter reading information to the customer system for billing. As a new application for the Company, this integration is currently being constructed, and will go through standard software lifecycle steps to be implemented to support Minnesota.

f. Meter Installation Vendor

This is a new integration that was required to coordinate the logistics with the third-party resource provider that is performing new advanced meter installations. The vendor will be utilizing its proprietary work order management system to manage their activities, and daily synchronization of information with the Company's system needs to occur in order to track and manage activities supporting the Company's customers throughout the deployment. Information that needs to be synchronized between the Company and the meter installation vendor includes customer contacts and responses, installation/removal of AMI meters, cancellation/updating of orders, disposed meters, and forecast data. This integration will keep the Company's systems that support personnel and customers reflective of the work planned and in-process. As a new integration for the Company, this required standard software lifecycle maintenance and upgrades to be implemented to support our Minnesota system and customers.

g. Network Management System (NMS)

NMS is the vendor supported application for the Company's Outage Management System (OMS). OMS is the enterprise solution for the electric trouble distribution control centers outage event management. OMS is critical to outage restoration and generally critical to the Company's operations. This would be a new integration for the Company, requiring standard software lifecycle management. We believe that AMI meter events and functionality can be utilized to better identify and manage service outages and restoration activity. The volume of data available from AMI systems must be pre-processed to produce timely, accurate, consumable, and actionable information for NMS, with appropriate inter-system routing. Such an integration of AMI and NMS would improve customer experiences during service outages by making the associated event details proactively available to personnel management, communications and decision-making during service restoration. This installation, integration and software development work (pre-processing) was initiated in 2021.

h. Distributed Intelligence (DI)

As discussed previously, DI is a processing capability within advanced meters that is controlled by a new meter application environment that is being deployed to support operational and customer application subscriptions. In other words, this DI capability allows for the installation of applications on the meter. On an end-to-end basis, the DI environment consists of an application platform, store, gateway, service bus, security manager, hub and analytics components. While the full scope of DI capabilities goes beyond initial AMI deployment, this environment must be minimally integrated so that the Company's meters can be properly and securely registered and grouped to support the deployment, administration, management and utilization of meter-based applications and services. The AMI program will test and validate the expected functionality of new advanced meter processing and the application environment, but will stop short of creating the full end-to-end scope of a DI solution, which involves a DI Agent running on the meter and corresponding back-end software applications to analyze the data and present the information in a useful way to customers or grid operators. The DI capabilities we have outlined and requested certification of in our 2021 IDP are therefore separate and incremental to this basic work needed to support initial AMI deployment, and focus on the creation of full DI solutions.

i. Meter Asset Lifecycle Management System

Meter Asset Lifecycle Management System manages the entire life cycle of serialized metering devices, including purchasing, testing, field installation location, field removal, and retirement of the asset. The Meter Asset Lifecycle Management System is currently integrated with the MDM System and CRS. The integration of the AMI head-end with the Meter Asset Lifecycle Management System will allow it to remain as the Company's primary source of location information and attributes for serialized metering devices. The AMI head-end will receive the meter location and attribute information to enable provisioning of the meter, understand its location, and obtain data from the meter.

j. Meter Data Management System (MDM)

The MDM system provides capabilities to validate, edit, and estimate meter readings and manages events from the meter, such as power outages and tampering. MDM will also assist in facilitating communication to, and receiving data from the AMI head-end. MDM is currently integrated with the Meter Asset Lifecycle Management

System and CRS. MDM will serve as the central repository for the reading data. The MDM will also validate the meter data and export it for use in billing, customer viewing, and analytics.

AMI significantly increases the number of meters and amount of data loaded to MDM. In 2019, we completed an evaluation of our current on-premises MDM system application and infrastructure after which we determined that an entirely new solution is needed to fulfill the requirements for AMI. The current on-premise MDM system application is approaching end-of-life and does not have the capacity and security elements required to support AMI, including the volume and technical capabilities needed for the Company-wide deployment of advanced meters. The central components of the new cloud-based MDM services have been installed, tested, provisioned and integrated to support the business processes for the initial AMI meter deployments. Configuration, testing and release work for MDM services are expected to continue to support the diverse rates and unique processes required to support each customer type across states throughout AMI deployment and operations. Once sequenced into that ongoing delivery schedule, on-premise historical meter data will also be transitioned to the new MDM system Ultimately, the MDM solution will support the security, functionality, scalability, and performance requirements of AMI meter data management.

k. Customer Portal & Future Applications (MyAccount)

The customer portal (the current version is available on the Xcel Energy website and is known by customers as MyAccount) is used by customers to obtain account information, track energy usage, view billing history, pay bills, and sign up for notifications. AMI data from field devices (i.e., the customer's meter) will move through the AMI head-end, and be integrated with other customer information, to the customer portal, where customers will have the ability to see more granular meter reading data than they see today.

After AMI deployment, we expect to begin rolling out new products and services to customers, some of which may require future filings with the Commission to determine details. These may include high bill alerts, personalized recommendations on energy usage, disaggregation of usage, and the capability to provide data to a customer's Home Area Network (HAN) and through the Company's utilization of Green Button Connect My Data (CMD).

l. FAN Integration

The AMI meter's two-way communication module is a component of the mesh network layer of the FAN. The meter's communication module retrieves meter data that is stored within the meter as prescribed by ANSI C12.19 meter table implementation standards. The RF communications modules in the meters may also act as a repeater for other mesh network devices, enabling two-way communication between the meters and the mesh network. This function has the benefit of increased reliability of communication between the AMI meters and the head-end application. In limited circumstances, where deployment of the Wi-SUN mesh network is not practical (such as remote locations on the edge of the Company's distribution system), meter data may be transmitted over the FAN via public cellular or other wireless technologies.

3. Systems Integrations – FAN

The FAN enables data and information from field devices to be communicated to ADMS, and also enables commands to be transmitted to the field devices from ADMS.

The following applications will interact directly with the FAN:

- AMI: The Wi-SUN mesh network, including the meters' communication nodes that will communicate as part of the network, will support AMI through the meters' communication function. The FAN will provide the transport for data transfer between the meters and the AMI head-end application, including interval reads, register reads, voltage information, and power quality data. It will also provide the sending and receiving of commands like power outage notifications and remote connect/disconnect commands.
- ADMS: The FAN infrastructure will provide data from field devices to the WAN, which will then deliver data to ADMS. The FAN enables data and information from field devices to be communicated to ADMS, and also enables commands to be transmitted to the field devices from ADMS. The FAN infrastructure will provide data from endpoint devices, such as meters and field devices, to a common Enterprise Service Bus (ESB) via the WAN, which will then deliver data to ADMS. The ESB will also receive commands from ADMS that will be delivered to the devices connected to the FAN via the WAN. The FAN enables data and information from field devices to be communicated to

ADMS, and also enables commands to be transmitted to the field devices from ADMS.

4. *Training and New Processes*

During the early stages of the AMI and FAN initiative, we conducted "blueprinting" sessions. The objective of these sessions is twofold: (1) to develop a complete set of requirements that can be used to build the applications, interfaces, reports, etc. needed to meet the objective of deploying AMI meters and fully integrating them into our backend systems and business processes; and (2) to develop the list of change impacts to the organization of going from the "as-is" to the "to-be" processes. These change impacts are used to develop an overall plan for managing those changes. From that overall change management plan, detailed plans for employee training (instructor led and computer-based course development and delivery) and other forms of engagement (i.e. through leadership forums and internal communications) are developed and executed.

The results of the blueprinting sessions are captured in workflows and used to compile a process document for each distinct business process and to serve as a reference for the "to-be" business process that drives the AMI technology being delivered. On an as-needed basis, the individual business areas may also develop more detailed procedures that build on the documentation from the blueprinting sessions. The blueprinting outcomes are also used to develop training to prepare employees for the new processes and to help lead our customers through all of the changes.

The training for AMI Minnesota has been developed and is in progress and consists of computer-based training (CBT), virtual instructor led training (VILT) and on-site instructor led training (OILT). The CBT is for multiple groups that will respond to customer inquiries about the AMI implementation, including an overview of AMI and the schedule, how to manage customer contacts, the optional AMI meter opt-out, and interval billing. Employees will take these CBT sessions based on the meter deployment schedule and cadence of external customer communications. The VILT content is for employees working in the customer billing area and is intended to give them hands-on experience with the Itron Enterprise Edition (IEE) software; this is where billing operations will process exceptions and populate any missing data needed for billing purposes. The OILT sessions are with field personnel, and again, based on the meter deployment schedule. The OILT content addresses common business practices such as meter maintenance and troubleshooting, meter receiving and testing, and manual contingency reads with new tools available with the new meters being installed. All training uses a "see, feel, touch" approach to help prepare the employees to be ready to support critical business functions and our customers through the meter deployment.

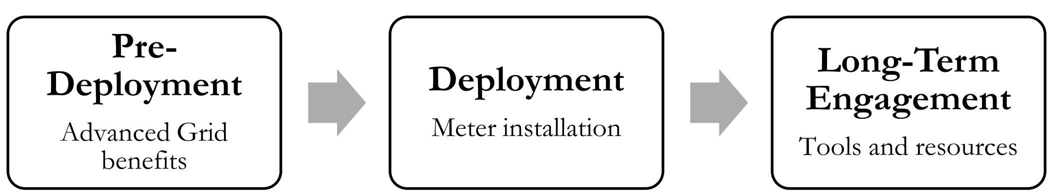
C. External Preparations

In Docket No. E002/M-20-592, we sought, and were granted, approval of changes to customer bills necessitated by the change to interval usage as the basis for customer bills and an AMI opt-out framework and tariff. As part of our compliance related to that proceeding, we worked with the Commission's CAO to review and finalize our customer deployment materials. We submitted the final materials on September 23, 2021, and provide a summary of our approach to customer communications associated with AMI deployment here.[28]

During our roll-out of new metering infrastructure, we are taking care to educate and inform our customers, and ensure a smooth implementation of new technologies. We have developed processes that will ensure accurate, timely bills as customers change over to AMI. We have also developed dedicated, hands-on customer-care processes that will provide our customers a single point of contact during implementation – and that will phase customer communications based on the geographic deployment of AMI meter installation.

Meter deployment and advanced meter capabilities will be phased in over the next several years, and communications strategies, messages and tactics will be executed in three phases to match the customer journey.

Figure 5: Customer Communications Journey Phases



[28] *See* Xcel Energy Compliance Filing, Docket No. E002/M-20-592 at: https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={10C3137C-0000-C81E-A89E-D55E52536131}&documentTitle=20219-178195-01 (September 23, 2021).

For example, our customer communications will begin pre-implementation with education on the capabilities of the new AMI meters, as well as customers' ability to opt-out of an AMI meter. As customers' AMI installation dates gets closer, we will inform them about what to expect with the AMI meter changeover at their homes or businesses. Finally, we will communicate post-AMI installation to reinforce early AMI messaging regarding possibilities and options – also providing practical steps to take advantage of the customer portal and other new or enhanced services available at the time of installation.

XI. METRICS AND REPORTING

AMI and FAN will be implemented over a number of years, beginning with customer outreach and education efforts, deployment of the systems and technologies, and then the roll-out of new and enhanced products and services. Our efforts will also include development and implementation of future products and services that will capture additional benefits of the advanced grid capabilities as customer preferences and technologies evolve over time.

Recognizing the significant investment that this advanced grid initiative requires, with our certification request, we proposed to report on a number of metrics that would provide progress reports to the Commission, and share information and learnings with stakeholders. We also noted that our AMI and FAN initiative may impact certain metrics that are part of our existing service quality reporting in those proceedings. Specifically, we report service quality metrics under our established Service Quality tariff[29] as well as the Minnesota Rules governing utility service quality.[30] We propose to continue reporting the service quality metrics in those reports, and intend to address any advanced grid impacts to service quality metrics or thresholds in those separate proceedings.

We continue to maintain that any metrics must be aligned with the benefits we anticipate from our implementation – which can only be known at the time the specific technology, design, scope and implementation plans are approved by the Commission; as such, the second set of metrics we outlined in our certification request were illustrative and would need to be refined based on the outcome of this cost recovery proceeding. Similarly, any metrics related to future operational capabilities or programs and services that are enabled by our AMI and FAN

[29] *See* the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.
[30] *See* Minn. R. 7826, Electric Utility Standards on safety, reliability, and service quality.

implementation or that may result from this proceeding, must be developed based on the specifics of those operational parameters or the programs and services that the Commission approves.[31] As such, although we do not oppose such metrics conceptually, it is premature to establish such metrics at this time. Instead, we believe it would be best to wait until the technology is fully operational, and then tailor the metrics based on the meters' actual functionality.

That said, one of the outcomes of the Commission's July 23, 2020 Order in Docket No. E002/M-19-666 certifying AMI and FAN was a request for the Department of Commerce (Department) to file a report with recommendations on specific metrics and detailed methods for evaluating performance; consumer protections; and other conditions.[32] The Department filed its *Methods for Performance Evaluations, Metrics, and Consumer Protections for AMI and FAN* Report December 1, 2020.

Among other things, the Department's Report recommended the Commission should approve, reject, or modify the Department's recommendations for methods to evaluate performance, and establish metrics and customer protections or, at a minimum, establish baseline considerations to be evaluated in the cost recovery petition.[33] We responded to the Report in our September 25, 2020 Response and October 30, 2020 Reply Comments. With respect to performance metrics, we reiterated our belief that the metrics we had proposed with our certification request were sufficient and appropriate to the initial implementation stage that we are now in – explaining that the two sets of metrics we outlined in our certification request would provide important, relevant, and appropriate insights into our AMI and FAN implementation from both operational and customer perspectives. Our intent with our proposed metrics was to provide the Commission and stakeholders comprehensive information on deployment progress for monitoring purposes, and performance and achievement of customer and system benefits as we implement the advanced grid initiatives.

We continue to believe the metrics we previously proposed are reasonable and appropriate. They will provide relevant information from a customer perspective for the Commission and stakeholders to monitor the progress of our AMI and FAN

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[31] *See* Xcel Energy 2019 Integrated Distribution Plan, Customer Strategy and Roadmap, Attachment M1 (Schedule 3), Docket No. E002/M-19-666 (November 1, 2019) and as updated in our 2021 Integrated Distribution Plan (Appendix B2), Docket No. E002/M-21-694 (November 1, 2021).
[32] The Report was originally due by November 1, 2020, but was subsequently extended to December 1, 2020 in the Commission's October 30, 2020 Order in Docket Nos. E002/M-19-666 and E002/M-20-680.
[33] *See* Department Report, General Recommendation No. 1 at page 13.

implementation from pre- to post-deployment from both operational and program and service perspectives.

That said, the Department's Report collected the metrics proposed by stakeholders and recommended the Commission require parties to use the metrics outlined in Appendix E of the Report as the baseline for consideration in the AMI and FAN cost recovery proceeding – and that final metrics should be established upon the conclusion of the initial AMI/FAN cost recovery proceeding, with the understanding that the metrics are expected to change and adapt as the Company seeks recovery of additional costs and project functionalities.[34]

In the balance of this section, we repeat our proposed metrics and outline our understanding of each of the recommended based metrics from Appendix E of the Department Report. We are happy to report that we are largely in alignment with the AMI- and FAN-related metrics that have been proposed.[35] There are however, several proposed metrics that are not related to our deployment of AMI and FAN, such as levels of various reliability, DER, and Non-Wires Alternatives-related items. These items are more appropriately addressed in other dockets such as our IDP, the Commission's docket for Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities (E999/CI-16-521) or the utility Annual Electric Service Quality Reports, as we note in the tables below. Additionally, some of the recommended metrics would not be possible for us to report on, either because they relate to comparisons to hypothetical futures or because they involve functionalities we do not intend to pursue at this time.

A. Company Proposed Metrics

As first stated in our certification request and further committed to in our September 25, 2020 Response to the Department's Notice, we are committed to report the specific metrics we proposed in Schedule 11 of the Gersack Direct Testimony, provided as Attachment M1 to our 2019 IDP and certification request.[36]

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[34] *See* Department Report at page 33, Metrics recommendation No. 2.
[35] Metrics originally proposed by the Company in its 2019 Integrated Distribution Plan and reproduced in these dockets in the Company's RESPONSE TO MINNESOTA DEPARTMENT OF COMMERCE NOTICE OF SOLICITATION OF STAKEHOLDER INPUT AND COMMENTS, page 6 (September 25, 2020) are reflected in the Metrics tables in *italics*.
[36] We note that because the Commission did not certify FLISR and IVVO, we have removed the metrics we proposed related to those technologies.

Table 11: Xcel Energy Proposed AMI and FAN Metrics

	Description	Reporting*
Customer Outreach and Education	Survey results of customers on the adequacy and clarity of communications prior to installation of advanced meters.	AGIS
Installation and Deployment	Number of advanced meters installed.	AGIS
	Percentage of FAN deployed.	AGIS
	Number of customers electing to opt-out of AMI installation.	AGIS
	Number of calls to Customer Contact Center and meter installation vendor regarding meter installation.	AGIS / SQ
	Number of complaints regarding AMI installation.	AGIS / SQ
Post-Deployment	Percentage of customers with advanced meters that receive estimated bills.	AGIS / SQ
	Percentage of customers with an advanced meter that have made a complaint of inaccurate meter readings.	AGIS / SQ
	Survey of customer satisfaction with outage related communications.	AGIS
	Number of customers with an advanced meter with an active web portal account.	AGIS
	Number of monthly, unique visits to the web portal (My Account).	AGIS

** Service Quality potential impacts and reporting noted.*

B. Department Report Appendix E Proposed Metrics

Below we present the metrics proposed by the Department and note whether we can support them immediately, which may be appropriate in the future, which we believe are more appropriate for other matters, and those we are not able to support because we are not able to calculate them.

Table 12: Customer Outreach and Education

Metric / Definition	Provide/ Frequency	Calculation/Notes
Survey results of customers on the adequacy and clarity of communications prior to installation of advanced meters	Yes – Quarterly	*Duplicate – See Table 6: Customer Engagement below* Rated satisfaction with communications received prior to AMI installation. *Note: part of AMI installation survey*

Table 13: Installation and Deployment

Metric / Definition	Provide/ Frequency	Calculation/Notes
Number of advanced meters installed	Yes – Quarterly	Count of meters installed by Service Point.
Percentage of advanced meters deployed compared to planned installation	Yes – Quarterly	Count of meters installed by Service Point / Total planned Service Points.
Percentage of customers with advanced meters	Yes – Quarterly	Meters installed by Service Point / Total Minnesota Service Points in the AMI deployment.
Percentage of FAN deployed	Yes – Quarterly	Number and percent of FAN devices deployed.
Percentage of FAN deployed compared to planned installation	Yes – Quarterly	Percent of FAN devices deployed / total planned devices.
Number of customers electing to opt-out of AMI installation	Yes – Quarterly	Count of customers (Service Points) selecting Manual Meter Reading Service Tariff.
Number of calls to Customer Contact Center and meter installation vendor regarding meter installation	Yes – Quarterly	Number of customer contacts related to AMI meter installation by month.
Number of complaints regarding AMI installation	Yes – Quarterly	Number of formal complaints received by month.
Number of intelligent field devices enabled by the FAN	*Potential Future*	Based on future intelligent device proposals.
Number of missed installation appointments	Yes – Quarterly	Will distinguish between customer and Company-missed appointments.

Table 14: Financial

Metric / Definition	Provide/ Frequency	Calculation/Notes
Total AMI project capital spend to-date vs. total AMI project capital budget	Yes – Annual	*Report by AMI/FAN and capital/O&M as follows:* **Project spend**: Actual NSPM Electric spend to-date plus current year forecast. **Budget baseline**: actual NSPM Electric spend to-date plus the remaining budget at a point in time.
Total FAN project capital spend to-date vs. total FAN project capital budget	Yes – Annual	
Total AMI project O&M spend to-date vs. total AMI project O&M budget	Yes – Annual	
Total FAN project O&M spend to-date vs. total FAN project O&M budget	Yes – Annual	
O&M cost savings from avoided field visits	Yes – Annual	*See* Table 8 – estimated O&M of Reduced Truck Rolls.
Avoided distribution capital costs due to reduced peak load from CVR programs	No	No current plans for a CVR program.

Table 15: Post-Deployment

Metric / Definition	Provide/ Frequency	Calculation/Notes
Percentage of customers with advanced meters that receive estimated bills	Yes – Quarterly	Estimated bill trends pre/post AMI installation for AMI/Non-AMI-based bills.
Total number of AMI meters use for billing (activated)	Yes – Quarterly	Same as Number of AMI Meters installed
Percentage of customers with an advanced meter that have made a complaint of inaccurate meter readings	Yes – Quarterly	Percentage of customers with AMI that have made a complaint about inaccurate billing.
Survey of customer satisfaction with outage related communications	Yes – Annual	Existing outage satisfaction survey.
Number of customers with an advanced meter with an active web portal (MyAccount) account	Yes – Quarterly	Count of customers that activate MyAccount post-AMI install. Activated is defined as within last 90 days.
Number of monthly, unique visits to the web portal (My Account)	Yes – Quarterly	Count of customers with an AMI meter that visit MyAccount.
Percentage of customers with an advanced meter with Home Area Network (HAN) functionality	Yes – Annual	AMI customers with HAN function enabled / Total customers with AMI.
Number of customers with an advanced meter with Home Area Network (HAN) functionality	Yes – Quarterly	Count of AMI customers with HAN enabled.
Percent of customers with an advanced meter with Green Button Connect My Data (CMD) functionality	Yes – Quarterly	Customers enrolled in CMD / total customers. *Note: All customers will have CMD functionality.*
Number of customers with an advanced meter with Green Button Connect My Data (CMD) functionality	Yes – Quarterly	Count of customers enrolling in CMD in previous 90 days. *Note: All customers will have CMD functionality.*
Number of customer/account inquiries regarding AMI or time-varying rates	*Partially* – Quarterly	Count of customer inquiries regarding AMI that are not reported as part of some other AMI-related call metric. *Note: any reporting of calls regarding time-varying rates would be a future metric tied to AMI-enabled rate options.*
Number of customers enrolled in time-varying rate programs	*Potential Future*	
Number of customers enrolled in other AMI-enabled demand management programs	*Potential Future*	
Number of avoided truck rolls/field visits	Yes – Annual	Total truck rolls pre- and post-AMI deployment. *Note: discussion may be necessary to determine avoided rolls due to AMI.*
Meter accuracy test percentage	Yes – Annual	Results of Random and Periodic tests of installed AMI meters
Percentage of interval reads received[37]	Yes – Annual	Interval reads received/total interval reads expected
Number of remote meter disconnect operations	*Future*	*Pending proposal and approval of remote disconnection/reconnection operations.*
Number of remote meter connect operations	*Future*	*Pending proposal and approval of remote disconnection/reconnection operations.*

Table 16: Customer Engagement

Metric / Definition	Provide/ Frequency	Calculation/Notes
Percentage of customers with advanced meter at least 30 days that are targeted with energy savings messaging	Yes – Quarterly	Monthly count of customers with AMI meters with targeted messaging in last 30 days
Percentage of low-income customers with advanced meters at least 30 days that are targeted with energy savings messaging	Yes – Quarterly	Monthly count of LIHEAP customers with AMI meters with targeted messaging in last 30 days
Percentage of customers aware of AMI	Yes – Annual	Customers aware of AMI / Total customers surveyed. *Note: Part of Residential Pulse Survey conducted 4x/year.*
Understanding of AMI technology and benefits	Yes – Annual	As part of our AMI installation surveys or Residential Pulse Surveys, we will ask customers questions to gauge their understanding of new meter technology and benefits. *Note: part of AMI installation survey and/or Residential Pulse Survey conducted 4x/year.*
Percentage of low-income customers aware of AMI	Yes – Annual	LIHEAP customers aware of AMI / Total LIHEAP customers surveyed. *Note: Part of Residential Pulse Survey conducted 4x/year.*
Adequacy and clarity of communications prior to AMI installation	N/A	*Duplicate – See* Table 1: Customer Outreach & Education above.
Number of customers with advanced meters that adopt an advanced rate option (e.g. TOU) tariff, expressed as a number and percentage by each rate	*Potential Future*	
Number of organizational events attended where information on AMI presented, by region	Yes – Quarterly	Defined as total events specifically hosted by Xcel Energy with information regarding AMI.
Demand Response: percentage participation by class	*Potential Future*	
DER: percentage adoption, by class	No	*Not related to AMI or FAN*. Otherwise reported in annual Docket No. E999/PR-xx-10
Storage: percentage adoption, by class	No	*Not related to AMI or FAN*. Otherwise reported in annual Docket No. E999/PR-xx-10
Customer access to hourly or sub-hourly data	Yes – Quarterly	Count of unique customers accessing energy usage data through the portal within last 90 days. *Note: AMI customers will be able to see sub-hourly data; non-AMI customers will see daily data.*
Third-party service access to customer data	No	Fulfillment of 3rd-party requests is reported in annual compliance filings in Docket Nos. E999/CI-12-1344 & E999/M-19-505.
Variety, quality, accessibility of customer data available (consistent with privacy and CEUD requirements)	Yes – Annual	Narrative explanation of customer data available to customers.

[37] This metric was repeated in the Appendix E to the Department Report (Post-employment metrics). *See* page 2 of 4

Table 17: Customer-Site Asset Effectiveness

Metric / Definition	Provide/ Frequency	Calculation/Notes
Demand Response: annual max MW reduction as a percentage of load, by class	*Potential Future*	
Demand Response: MW enrolled as percentage of load, by class	*Potential Future*	
DER: MWh generated as percentage of sales, by class	No	*Not related to AMI or FAN* Reported in annual Docket No. E999/PR-xx-10
DER: MW installed as percentage of load, by class	No	*Not related to AMI or FAN* Reported in annual Docket No. E999/PR-xx-10
Storage: MWh installed energy capacity as percentage as percentage of sales, by class	No	*Not related to AMI or FAN* Reported in annual Docket No. E999/PR-xx-10
Storage: MW installed capacity as percentage of load, by class	No	*Not related to AMI or FAN* Reported in annual Docket No. E999/PR-xx-10
Non-Wires Alternatives (NWA): MW as percentage of (peak) load	No	*Not related to AMI or FAN*
NWA: percentage of customers participating, by class	No	*Not related to AMI or FAN*
NWA: savings ($) per year	No	*Not related to AMI or FAN*
Percentage of grid supporting services provided by DER vs. traditional solutions	No	*Not related to AMI or FAN*

Table 18: AMI Capital and O&M

Metric / Definition	Provide/ Frequency	Calculation/Notes
Capex for Asset Health/Reliability, Capacity Projects	No	*Not related to AMI or FAN* Already reported annually in the Integrated Distribution Plan (IDP)
Capital – Storm related restoration costs	No	*Not related to AMI or FAN* Already reported in the IDP
Capital – AMI meter failure rate (avoided meter purchases)	Yes – Annual	Number of failed AMI meters to-date / Total AMI meters deployed to-date
O&M – Annual trips for damaged customer equipment	Yes – Annual	Total customer claims submitted Total customer damage claims paid
O&M – Annual trips for residential manual disconnection	Yes – Annual	Estimated O&M based on average cost per trip.
O&M – Annual trips for residential manual reconnection	Yes – Annual	Estimated O&M based on average cost per trip.
O&M – Annual "OK for Arrival" field visits	Yes – Annual	See Table 15, Number of avoided truck rolls/field visits. *TBD based on definition.*
O&M – Annual voltage investigation field visits	Yes – Annual	See Table 15, Number of avoided truck rolls/field visits. *TBD based on definition.*
O&M – O&M for Asset Health/Reliability, Capacity Projects	No	*Not related to AMI or FAN* Available O&M data reported in the IDP
O&M – O&M for storm related activity	No	*Not related to AMI or FAN* Already reported in the IDP

Table 19: AMI Other

Metric / Definition	Provide/ Frequency	Calculation/Notes
Customer-minutes of outage (CMO) – major events	*Is possible*	Suggest this reporting be considered in conjunction with existing reliability reporting in the annual Service Quality report proceedings for proper context.
CMO – single customer events	*Is possible*	Suggest this reporting be considered in conjunction with existing reliability reporting in the annual Service Quality report proceedings for proper context.
CMO – tap level events	*Is possible*	Suggest this reporting be considered in conjunction with existing reliability reporting in the annual Service Quality report proceedings for proper context.
Cost of consumption on inactive meters	Yes – Annual	Reduction in unbilled energy usage on meters not assigned to a billing account.
Commodity bad-debt expense	*Future*	Total bad debt expense in relation to total residential customers. *Note: Only relevant to AMI after the Company employs remote disconnect/reconnect, which is a future capability subject to Commission approval.*
Residential demand shift from TOU rates	*Potential Future*	Already committed/obligated to report on this metric as part of the Performance Based Ratemaking Docket No. E002/CI-17-401.
Medium C&I demand shift from TOU rates		
Residential peak demand reduction from Critical Peak Pricing		
Medium C&I peak demand reduction from Critical Peak Pricing		

CONCLUSION

In summary, AMI and FAN are critical foundational elements of our grid modernization strategy – and now is the appropriate time to implement for our customers and for our operations. These technologies will work together to address system and customer needs, enhance our service to customers, and open up new opportunities for future products and services that will help our customers share in our strategic priority to lead the clean energy transition. The system visibility and data delivered by AMI and FAN will provide customer benefits in reliability and information, as well as the ability for remote connection, and greater customer offerings for rates, programs, and services. AMI and FAN will also enhance the Company's planning and operational capabilities by giving access to timely, accurate and consistent data. From this data, we will provide enhanced information directly to customers, allowing them to make better informed decisions about their energy usage. We are excited to begin this step change in advanced technology and the benefits it will bring our customers and our operations.

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

Attachment 4A contains protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b), Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a) and are marked as "NOT PUBLIC." The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy.

Attachment 4A provided with the NOT PUBLIC version of this filing contain information classified as trade secret pursuant to Minn. Stat. § 13.37 for the above-noted reasons and are marked as "NOT PUBLIC" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment 4A:

1. **Nature of the Material**: The AMI Cost Benefit Analysis Model developed by the Company.
2. **Authors**: Risk Analytics
3. **Importance**: The Company work product is proprietary to the Company.
4. **Date the Information was Prepared**: The CBA Model was created in the third quarter of 2019 and updated in third quarter 2021.

Overview and Bidder Instructions

Dear Bidder,

You have been invited by Xcel Energy Services Inc. (hereinafter referred to as "Xcel Energy") to submit information in response to a request proposal ("RFX"). This document contains important information about Xcel Energy and the RFX and we suggest you take the time to read it carefully. We look forward to your proposal submission using our electronic sourcing system (the "eSourcing System").

Thank you.

About Xcel Energy at www.xcelenergy.com

Our name reflects our core value — excellence in energy products and services. We are dedicated to providing you the best in service, value and information to enhance your professional and personal life. We are committed to customer satisfaction by continuously improving our operations to be a low-cost, reliable, environmentally sound energy provider. We have been successfully proving this to our customers for more than 130 years and will work hard to continue with this commitment in the future.

As a leading combination electricity and natural gas energy company, we offer a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers.

We have regulated operations in 8 Western and Midwestern states, and revenue of more than $9 billion annually; and own more than 35,000 miles of natural gas pipelines. We are proud of our community involvement. Through the Xcel Energy Foundation, our economic development activities, and employee volunteer efforts, we are committed to using our considerable resources and skills to benefit the communities we serve.

Our environmental policy states that Xcel Energy will be valued as a leader in the energy industry by demonstrating excellence in environmental performance. The most recent National Renewable Energy Lab's ranking of green pricing programs ranked our Windsource® and Renewable Energy Trust first in number of customers and fifth in energy sales out of over 500 U.S. utilities. Our key environmental commitment includes improving air quality, conserving resources, harnessing renewable energy, and protecting wildlife and habitats.

Proposal Evaluation Criteria

Xcel Energy's objective in sourcing via the eSourcing System, Emptoris, is to obtain goods and services that best meet technical and functional requirements at the best price. Proposals will be evaluated by Xcel Energy on the basis of the information provided by you through the eSourcing System. The lowest price proposal may not indicate the best overall evaluated proposal. The following criteria may be used by Xcel Energy in its consideration (not necessarily listed in order of importance):

- Bidder's understanding of and responsiveness to the scope of work, technical specifications and other requirements
- General feasibility of the bidder's plan to meet the requirements of the scope of work and/or technical specifications
- Bidder's ability to meet the stated work schedule
- Bidder's acceptance of the general terms and conditions
- Bidder's experience with similar work and safety record
- The evaluated total cost of the services and/or goods
- The quality of services offered by the bidder

- Comprehensiveness of the bidder's proposal, including options
- Bidder's diversity classification or utilization of diverse suppliers as subcontractors; and demonstration that bidder has made good faith efforts to provide maximum practicable subcontracting opportunities to diverse suppliers

Bidding Instructions

Failure to comply with these bidding instructions may disqualify a bidder from further consideration.

- Xcel Energy requires that all bidders (and their subcontractors, alliances, or partners) provide a single point of contact during the RFX process.
- In the eSourcing System, click on the green **"Accept"** button to indicate your intention to respond or click the red **"Decline"** button to indicate your intention not to respond. During the course of your review and response you can indicate that you wish to not proceed further.
- Correspondence or questions concerning the RFX content and attachments **must be sent using the eSourcing System's messaging functionality** to the Xcel Energy Sourcing & Purchasing Contact / ("Event Owner"). The name of the "Event Owner" is listed in the upper left hand corner of the RFX, labeled as "Contact Information". Instructions on how to send messages are provided in the computer based training module titled *Using System Messaging*. All responses to technical questions will be answered via the eSourcing System's messaging functionality to the RFX and issued to all bidders. Contacting anyone besides the Event Owner about this RFX may be grounds for disqualification.
- All bidding, both qualitative and quantitative, will be submitted through the eSourcing System. You will be asked to answer a number of questions, including pricing on items.
- All submissions must be submitted on time per the schedule indentified in the RFX. Late submittals will not be accepted.
- All submissions must be complete in order to be evaluated. **Incomplete submissions will not be accepted.** The bidder's proposal must be all-inclusive to provide complete and reliable services and/or goods to meet the requirements and technical specifications documented in the RFX.
- The bidder shall not alter any part of the RFX in any way except by stating all exceptions in a response to the appropriate question or as an attachment to the appropriate question with a detailed explanation for each exception.
- Any modification made to the RFX by Xcel Energy will be made through the eSourcing System.
- The bidder shall separately state in its proposal all taxes (including sales, use, and other excise taxes) it believes to be imposed by law upon the transfer of equipment or other materials to Xcel Energy or upon the provision of services. Please contact the Event Owner for applicable tax rates.
- If you have difficulties with the eSourcing System, you may contact the Xcel Energy Supply Chain Hotline at 303-628-2644 from 8:00 a.m. to 5:00 p.m. (MST) Monday through Friday.

RFX Terms and Conditions

In addition to the terms and conditions you accepted on the eSourcing System login screen, the following terms and conditions apply to the RFX:

- **Bidder's submission of proposal information in response to this RFX shall constitute bidder's agreement to these terms and conditions.**
- All costs associated with bid preparation and the provision of related documents are to be borne by the bidder.

- Xcel Energy reserves the right to open proposals privately and unannounced, and to be the sole and final judge of all proposals.
- Bidder's proposal is genuine and not made in the interest of or on behalf of any undisclosed person, firm, or corporation and is not submitted in conformity with any agreement or rules of any group, association, organization, or corporation; bidder has not directly or indirectly induced or solicited any other bidder to submit a false or sham proposal; bidder has not solicited or induced any person, firm, or a corporation to refrain from bidding; and bidder has not sought by collusion to obtain for itself any advantage over any other bidder or over Xcel Energy.
- Bidders shall take no advantage of any apparent errors or omissions in any related documents. If a bidder believes there are errors or omissions in supplied documentation or if the bidder is in doubt as to the meaning of any part of the documentation, bidder is to contact the Event Owner via the eSourcing System's messaging functionality before the close of the RFX. If Xcel Energy agrees that a change is required or if any explanation or interpretation is required, Xcel Energy will modify the RFX and notify bidders via the eSourcing System messaging functionality.
- The bidder agrees that, if its proposal is accepted, it will remove taxes from any charges to Xcel Energy upon receipt of a properly completed exemption certificate or direct pay tax license number. Except with respect to taxes imposed by law upon the transfer of equipment or other materials to Xcel Energy, the bidder shall pay all other taxes, tariffs, import duties, entry fees, permit fees, license fees, and other charges of any kind incurred in performing the activities contemplated by its proposal; and all such expenses shall be included in the price. If the bidder is in doubt about whether it may incur any such expense, and it would reduce its charges to Xcel Energy by the amount of such expense in the event such expense is not incurred, then the bidder shall explain the nature and amount (if known) of any such expense in its proposal.
- Xcel Energy reserves the right to reject any or all proposals, including without limitation the rights to reject any or all nonconforming, non-responsive, irregular or conditional proposals and to reject the proposal of any bidder if Xcel Energy believes that it would not be in the its best interest to make an award to that bidder. Bidder agrees that any such rejection shall be without liability on the part of Xcel Energy nor shall bidder seek any recourse of any kind against Xcel Energy because of such rejection.
- Xcel Energy may enter into discussions with the bidder proposing the best overall evaluated offer on the terms of the attached general conditions, scope of work and/or technical specifications, and other attachments.
- All proposals shall become the property of Xcel Energy.

Additional Information

For additional eSourcing System information, visit https://www.xcelenergy.com/working_with_us/suppliers

Electric AMI Meters and Installation Request for Proposal v12

February 21, 2018

Table of Contents

1 Introduction and Background

Xcel Energy Services Inc. and its operations affiliates (collectively, for purposes of this Request for Proposal (RFP), "Company") are proceeding with establishing Advanced Metering Infrastructure (AMI) as a fundamental and essential component to an implementation of Company's Advanced Grid Intelligence and Security (AGIS) initiative.

In this RFP, Company solicits Proposals from vendors (hereafter referred to as "Suppliers"), for the supply of electric Meters and electric Meter exchanges (installation). Such Meters shall be required to be technically and operationally compatible with a Head-end and Network acquired from Itron Networked Solutions (INS) (previously Silver Springs Networks (SSN), under a separate contract.

Currently, Company only intends to enter into a firm commitment for the supply of electric Meters for Company territories served by the PSCo (Colorado) Operating Company. As such, Company seeks firm bids for the supply of electric Meters and the installation of electric Meters in the PSCo region. Company also seeks information and indicative pricing for an enterprise-wide deployment of electric AMI Meters.

Suppliers who are adequately qualified are invited to respond to this RFP following the instructions that are provided in this document set.

1.1 Abbreviations, Short Forms, and Acronyms Used in this Document

Refer to Appendix 1 for a detailed list of abbreviations, definitions, short forms, and acronyms.

1.1.1 Nomenclature Concerning "Meters" with Capitalized "M"

For clarity, in this document the word "Meter" with a capital "M" means an electric meter that is suitably equipped with a Network Interface Card (NIC) also known as an electric AMI Meter. A "Meter" consists of a carefully calibrated measurement instrument that is normally connected to a wireless network by way of a NIC, for residential or commercial and/or industrial applications.

1.2 AMI Meter Vision and Priorities

Company AMI Meter strategy is to coordinate integration of a multitude of business needs and applications into a common platform that can be leveraged enterprise wide by Company's business units. Company has selected Itron Networked Solutions as its AMI network solution provider.

AMI data will provide Company a return on investment and make a positive impact on moments-that-matter in the customer lifecycle. AMI provides enhanced functionalities such as:

1. Voltage metrics for Integrated Volt/VAR Optimization (IVVO) application.
2. Premise-specific information to corroborate Momentary Average Interruption Frequency Index (MAIFI) events.
3. Premise-specific outage management and storm restoration capabilities, including near real-time views of restorations.
4. Power quality event capture, to enhance response time and proactively resolve distribution problems.
5. Tamper and energy theft detection in collaboration with data analytics.
6. Distributed Energy Resource (DER) monitoring.
7. Remote electric service connect/disconnect capabilities, reducing truck rolls.
8. Scheduled and on-demand Meter reading, enhancing billing and customer management.
9. Provide customers with data enabling more efficient energy use.
10. Ability to offer variable rate structures such as CPP, PTR, TOU, etc.
11. Provide enhanced demand response programs.

12. Enable use of downstream monitoring devices for special rates, e.g. DER and Electric Vehicle (EV) charging.
13. Maximizing life of existing or new infrastructure.

Company's wireless mesh network will adhere to the Neighborhood Area Network (NAN) Field Area Network (FAN) profiles that are founded on the IEEE 802.15.4g and IEEE 802.15.4e standards. This results in a cohesive, standards-based, wireless mesh network intended to provide reliable network services across a wide geographic area, all owned and managed by Company.

When fully deployed, the network will be fault tolerant in design and topology and be multi-tenant in nature, meaning multiple applications will share the same communication infrastructure. The multi-tenant nature of the network has mandated the necessity to implement the network with proven, reliable, and efficient end-to-end message priority forwarding protocols.

Company has a companion WiMAX (Worldwide Interoperability for Microwave Access) project underway, for the primary purpose of establishing a wireless backhaul backbone for much of the service territory. WiMAX is a point-to-multipoint technology providing broadband data services and an extensive Quality of Service (QoS) feature set. In the context of this AMI project, WiMAX will be the data backhaul technology of choice for mesh networks. WiMAX will be used at transition points from the mesh network to provide transport services along a path toward Company's core network.

Company places priority emphasis on its cyber and physical security programs. Company seeks to continuously and proactively plan, refine, and exercise appropriate levels of attention, action, and response to security issues and threats to the intelligent grid. This project will help to ensure all AMI and FAN components are identified and protected, both for the protection of customers and for the reliable and safe delivery of energy to customers. Additionally, Company will apply its cyber security program to validate sufficiency of security controls that are integrated with the AMI Meters. These activities, and others, help to protect, proactively and reactively provide customer privacy, detect suspicious behavior, events and/or anomalous activity, and provide the information necessary to respond to and mitigate security threats.

Company strives to adhere to world and industry standards in ways that promote multi-supplier interoperability, industry innovation, and operational flexibility, and that are exampled in such domains as Wi-Fi, Ethernet, and 3GPP. Company is a Wi-SUN Alliance member and supporter, and stands behind the basic principles of the organization. This will enable Company to realize value when installing successively new generations of Meters. This is a goal toward which Company expects that its Supplier will adhere.

1.3 Project Scope of Supply

1. The Scope of Supply is inclusive of the following items:

   a. Electric Meters, meeting the requirements, as outlined herein.
   b. Optional Electric Meter Installation as outlined herein, in Section 8.
   c. Warranty provisions covering supplied goods in Section 9.

2. Subsequent to a successful RFP process, Company may award a bid to a single Supplier, or multiple Suppliers, for various items in the Scope of Supply.

3. The table below indicates electric Meters that are presently acceptable for supply to Company. Company will qualify and acceptance test future meter types that may become commercially available to maintain up-to-date technologies and applications.

Table 1: Electric Meter Models/Series

Elster	Residential RX4

Elster	Commercial A4
Itron	Residential Centron II
Itron	Commercial Centron Poly-phase
Aclara	Residential I-210+
Aclara	Commercial KV2c
Landis+Gyr	Residential Axe-SD
Landis+Gyr	Commercial S4x

4. Goods shall be supplied to Company in quantities and with options that are specified in the Electric AMI Master Pricing Template v1.0.xlsx. Company expects Supplier to provide pricing for both bundled and unbundled services and goods. Bundled pricing is for Suppliers that offer discounted pricing for some of the components if goods and services are bundled together. Unbundled pricing assumes various components could be awarded to multiple Suppliers.

5. During AMI Meter deployment, in August of each year, Company will provide Supplier with anticipated Meter purchases by month for the following year. Refer to Appendix 4 for the anticipated electric Meter purchase timelines for purchase and delivery of Meters to support the PSCo deployment.

6. All supplied Electric Meters shall be equipped with the INS Generation 5 NIC as specified herein, including but not limited to:

   a. 32MB of RAM for residential and commercial NICs.
   b. 600 kbps speed for residential and commercial NICs or other options Company might select in the future as offered by INS.
   c. HAN Radio.
   d. 5-year all-inclusive warranty on residential and commercial NICs. Base Meter price shall reflect 5-year all-inclusive warranty.
   e. All future options as selected by Company and offered by INS.

7. Electric AMI deployment schedule. (Note: PSCo deployment dates are firm. Deployment in other Operating Companies is conceptual and subject to change based on Company planning development and regulatory alignment.)

   a. PSCo (CO)
      i. Electric Meters
         1. 1% in 2019 – 15,876 Meters: Begin Q2 2019
         2. 10% in 2020 – 158,760 Meters: Begin Q1 2020
         3. 25% in 2021 – 396,901 Meters: Begin Q1 2021
         4. 30% in 2022 – 476,281 Meters: Begin Q1 2022
         5. 29% in 2023 – 460,405 Meters: Begin Q1 2023
         6. 5% in 2024 – 79,380 Meters: Q1 2021 – Finish Q2 2024

   b. NSPM (MN)
      i. Electric Meters
         1. 1% in 2019 – 17,500 Meters: Begin Q3 2019
         2. 7% in 2020 – 98, 000 Meters: Begin Q1 2020
         3. 10% in 2021 – 140,000 Meters: Begin Q1 2021
         4. 45% in 2022 – 630, 000 Meters: Begin Q1 2022
         5. 37% in 2023 – 477,000 Meters: Begin Q1 2023
         6. 7% in 2024 – 36,000 Meters: Begin Q1 2024 – Finish Q2 2024

   c. NSPM (ND)
      i. Electric Meters
         1. 50% in 2020 – 50,000 Meters : Begin Q1 2020
         2. 50% in 2021 – 50,000 Meters: Begin Q1 2021 – Finish Q4 2021

   d. NSPM (SD)

i. Electric Meters
1. 50% in 2020 – 50,000 Meters : Begin Q1 2021 - Finish Q4 2022
2. 50% in 2021 – 50,000 Meters: Begin Q1 2022 – Finish Q4 2022

e. NSPW (WI and MI)

i. Electric Meters
1. 30% in 2023 – 84,000 Meters: Begin Q1 2023
2. 40% in 2024 – 112,000 Meters: Begin Q1 2024
3. 30% in 2025 – 84, 000 Meters: Begin Q1 2025- Finish Q4 2025

f. SPS (TX and NM)

i. Electric Meters
1. 50% in 2023 – 205, 000 Meters: Begin Q1 2023
2. 50% in 2024 – 205, 000 Meters: Begin Q1 2024 – Finish Q4 2024

1.4 Essential Requirements for Detailed RFP Assessment

Per Section 2.1 of this RFP, Supplier responses will be assessed by Company in detail on the condition that Supplier is able to satisfy Company that they are capable of meeting and/or exceeding the essential requirements set out here.

Responses to this RFP that fail to satisfy Company that Supplier has the ability to meet these essential requirements, might result in Company not conducting a detailed assessment of Supplier RFP responses.

The essential requirements are:

1. Supplier demonstrates the capacity, or offers assurances for factory output capacity, that meets Meter delivery requirements.
2. Supplier demonstrates compliance to requirements outlined in section 3.4 and Supplier is qualified, capable, and equipped to offer and deliver all or some of the items identified in the scope of supply in Section 1.3, suitably equipped with communications interfaces and with all of the necessary features and functionality that are necessary to interface to Company's network and Head-end systems.
3. Supplier satisfies Company that:
   a. Supplier has executed a legally binding reseller agreement with the third party NIC Supplier (Itron Networked Solutions) that meets or exceeds the legal and contractual conditions set out herein) and evidences its legally binding reseller agreement with the third party NIC Supplier as an attachment to the response to this RFP.
   b. Supplier has, or will have, fiscally sound, business amicable, and legally binding Joint Development business arrangement with Itron Networked Solutions that guarantees that:
      i. Includes, in its third party legally binding reseller agreement, full scope partnering relationships that guarantee Company ongoing product supply, and that include the unified benefits of electric metrology and NIC enhancements beyond the current generation of products for a period of twenty (20) years.
      ii. Grants adequate influencer rights to any any Joint Technology Development arrangement with Company.
4. Per Sections 6 and 7, Supplier offers full feature support for the following classes and forms of electric Meter models listed in Section 1.3:
   a. Class 20 forms 3S, 5S, 6S, 9S, 36S and 45S
   b. Class 200 forms 1S, 2S, 12S and 16S

c. Class 320 forms 2S, 12S and 16S

5. Per Sections 6 and 7, concerning essential operational features:

   a. All residential type electric Meters are capable of measuring voltage, current, temperature, power, reactive power, apparent power, power factor, and harmonics.

   b. Reactive energy is made available as a load profile interval channel recording alongside other energy quantities, e.g. kWh.

   c. All electric Meter types are offered and equipped with optical ports with metal rings for magnetic connection.

   d. All electric Meters are equipped to sense and measure internal Meter temperature, and the parameter is made available as a load profile interval channel recording, along-side other energy measurement quantities. Additionally, electric Meter is equipped to provide an alert on internal user-defined Meter temperature threshold.

6. Supplier Meter offerings are inclusive of the Itron Networked Solutions Gen 5 NIC and Supplier demonstrates long-term, progressive, three-way business/technology relationships.

7. Supplier adheres to and adequately demonstrates that it adheres to Company's main cyber security principles, that is:

   a. Utilize cyber security best practices based on standards established by various government organizations such NIST, IEEE, IEC, SEPA, etc.

   b. Defense-in-Depth: Ensures there are multiple layers of protection and detection defined.

   c. Zero Trust: Creates isolation points within the information network so only specific hosts are able to communicate with other specific hosts.

   d. Tightly-Controlled Access: Ensures only necessary people and systems are able to access devices or software.

   e. Least Privilege: Only necessary individuals and services are allowed to interact with devices.

   f. Hardened Equipment with Hardened Operating System (Meter Operating System): Only necessary ports and services are open and running on the systems and devices.

8. Suppliers wishing to participate in the AMI Meter Supply RFP process shall participate in testing of the proposed Meters. The testing program will be carried out by Company with Supplier support.

9. Company prefers electric meters that do not require batteries for operation. If Supplier requires batteries for meter operation, Supplier is required to provide details on batteries that include, but are not limited to: battery manufacturer and specifications, performance under various conditions, expected life, etc.

10. Section 6.3.19 (Residential section) and 7.3.19 (Commercial section) of this RFP shall apply to AMI meters deployed in the PSCo territory.

2 General Provisions

2.1 Invitation to Bid

1. This RFP invites Suppliers to submit proposals setting forth all terms, including pricing, for provision to Company, of the equipment and services listed herein, at all of the required locations set out herein.

2. Suppliers are required to provide insurance documentation, security questionnaire, and complete a subcontracting diversity form.

3. Suppliers who are participating in this RFP are required to confirm that they are able to supply equipment and services that are functionally in-line with Company's vision, and in substantial conformance to the Essential Requirements set out herein.
4. Prior to carrying out a thorough assessment of Supplier responses, Company will evaluate Supplier responses to the Essential Requirements (Section 1.4), and where Suppliers are able to demonstrate that their solutions are sufficiently in compliance with Company's vision and requirements, the balance of the RFP response will be comparatively assessed against functional and technical requirements of the RFP.
5. In order to propose the provision of the Equipment and/or Services as specified in this RFP, Supplier, in addition to any other requirements in this RFP, shall:
    a. Have signed the pre-requisite Confidentiality and Non-Disclosure Agreement with Company.
    b. Have significant, demonstrable experience providing the same or similar AMI Equipment and Services as those identified herein.
    c. Be able to provide the Services and/or Equipment at all of the required locations set out herein, either by itself or through a subsidiary, affiliate, parent company or its partner, all of whom are otherwise qualified as defined in this RFP.
    d. Demonstrate that its financial situation is sound (refer to Section 3.4–Corporate Profile).
6. In order to propose the provision of any components of this RFP, Suppliers must comply with the applicable requirements of this RFP.

2.2 Critical Dates in the RFP Process

Table 2: Critical Dates for RFP Processing

No	Scheduled Item	Required Schedule
1	RFP Released to Suppliers	March 8, 2018
2	Multi-Round Vendor Clarifications	March 9, 2018 - March 22, 2018
3	Meter Qualification Testing	Begin October 25, 2017; end May 16, 2018
4	RFP Responses Delivered to Company	March 29, 2018
5	Supplier Onsite Presentation	April 2 – 5, 2018

2.3 Instructions to Suppliers

The following instructions are additional to those provided in the attached document titled: Instruction to Bidders. Instruction to Bidders can be downloaded from Company Emptoris website.

2.3.1 Company Emptoris Response Procedures

1. Suppliers are required to respond to this RFP using Company Emptoris Secure Internet Sourcing System. Follow the instructions set out herein:
    a. Logon to Xcelenergy.esourcing.emptoris.com.
    b. Enter Supplier Username in the Name field.
    c. Enter Supplier Password in the Password field.
    d. Click the Login button.
    e. From the Main Menu, select RFx(s) > Manage RFx(s).
    f. Locate the RFx Name in the list of RFx(s).
    g. Click on the RFx Name link to view the RFx.
    h. Click the green "Accept" button in order to enable response function.

2. Note: Once you have reviewed the RFP material, please click the Green "Accept" button as your intention to bid or the Red "Decline" button as an indication that you will not be participating.
3. Be sure to answer all questionnaires and questions.
4. Pricing shall be submitted via the "Single Bid" tab or "Multibid" Tab. Please adhere to the format, no other formats will be accepted unless otherwise approved by Company.
5. Suppliers are required to address the following documents which are attached to the event. Please download these, and upon review, upload your return documents with your "Supplier name + original document name" included in the file name so submissions may be deciphered. Documents include:
    a. This RFP.
    b. Instructions to Bidders.
    c. Sample No Opportunity for SUB Letter.
    d. Sub-Contracting Plan.
    e. Sample Insurance Certificate.
    f. General Conditions Major Supply Agreement – Any redlines should be documented on the original document and returned as an attachment. Note that any exceptions will be weighted and may preclude Supplier from further engagement in the sourcing process.
    g. Company Electric AMI Master Pricing Template v1.0.xlsx.
    h. Safety Program Requirements.

2.3.2 Response Requirements

1. Suppliers are required to respond to this RFP with a wholly compliant response. That is, a response that is intended to directly, and without modification to the terms and requirements, meet and/or exceed the terms and requirements set out herein, and be inclusive of full and complete pricing.
2. Where Suppliers are responding with a whole and complete compliant response to this RFP, Suppliers are invited to offer separately prepared, and separately attached, RFP response Amendments that present Company with alternatives. Under such conditions, Suppliers must:
    a. Have first prepared and completed a wholly, and fully priced response to this RFP.
    b. Not alter Company's methodology for Network and Head-end design and buildout.
    c. Document the proposed amendment(s) in the form of one or more fully priced options that Company may or may not avail itself.
    d. Include, in its proposed amendment(s), full and complete descriptions, and demonstrate the technical, operational, and economic benefits of the amendment.
    e. Include, in its amendment(s), clear statements that define any business, operational, or technical implications if Company chooses any of the proposed amendment(s). Such include, but are not limited to: long term support implications, any remedial work that may be required, implications to other Suppliers with whom Company is conducting business.
    f. Include, in its amendment(s), full and complete pricing, including components of pricing where prices may increase or decrease so as to achieve the benefits of the proposed amendment.

2.3.3 Pricing Methodology

1. Pricing is structured and tendered into various components:
    a. Electric Meters
    b. Optional Electric Meter Installation
    c. Warranty Provisions

2. Supplier pricing shall include volume breaks/volume discounts.
3. Suppliers are required to tender pricing through completion of the pricing template attached here as: Electric AMI Master Pricing Template v1.0.xlsx.
4. Following a period of assessment and negotiation, Company expects to:
    a. Form a Major Supply Agreement (MSA) and companion Statement of Work (SoW) for all, or a portion, of the supply components.
    b. Optionally, select and award one or more Meter Installation offer(s).
    c. Optionally, select and award one or more of the components outlined in Section 1.3 on scope.
5. Supplier shall offer pricing that is valid for at least nine (9) months from receipt of RFP responses.
6. Supplier to also include pricing for facility rental or warehousing space required to support deployment activities.

2.3.4 Pricing Modules

1. Pricing is required to be tendered in the form of itemized tables in the Xcel Energy Electric AMI Master Pricing Template v1.0.xlsx.

2.3.5 2018 Tax Reform

1. It is understood that most US corporate entities will benefit from the corporate tax reform aspects of the 2018 Tax Cuts and Jobs Act. Supplier shall engage in open book discussion with Company about the impact of the tax reform, primarily but not limited to that benefit derived from the reduction in the corporate income tax rate, and share transparently how this is taken into account in the development of pricing provided in response to this RFx?

2.3.6 Managing Questions and Inter-Company Communications

1. Prior to submitting questions, Suppliers are requested to review the full RFP, formulate Supplier's questions, and submit them via the Emptoris portal in compliance to the schedule. Company will then respond to Supplier's questions in compliance to the schedule.
2. Questions are required to be submitted in batched written format. Please batch Supplier's questions using two (2) segments: 1) Electric Meters and 2) Electric Meter Installation.
3. All questions and answers will be distributed equally to all participating Suppliers for transparency purposes.
4. Suppliers are directed to communicate all questions via Company Sourcing: contact Edem Umoh (612-342-8945) or Dan Pendar (612-330-6521).

2.3.7 Evaluation Procedures for Proposals

1. Where Supplier Responses meet evaluation conditions set out in Essential Requirements–Section 1.4 herein, Supplier's response will be evaluated considering the following:
    a. Testing evaluations
    b. RFP Proposal Responses, including ability to meet industry acceptable standards
    c. RFP Pricing
    d. Acceptability toward synchronization with Company goals and vision
    e. Ability to meet execution timing
    f. Ability to meet Company's current and future needs

2.3.8 Contact Information

Suppliers are required to include in their response a table indicating the parties with whom Company may communicate in regard to the content of individual Sections. The following Table is a reference template:

Table 3: Contact Information – Example Supplier's Fill-in Table

RFP Section	Business Area	Team Member	Lead or Subject Matter Expert	Email Address	Telephone No.
	Business Terms and Conditions				
	AMI Electric Meters				
	Electric Meter Installation Services				
	Third Party Contractual Arrangements				
	Warranties				
	MSA				
	Installation Services				

2.3.9 Required Submittals

Suppliers responding to this RFP are required to submit the following documentation, attached in the form of Annexes.

1. Meter and NIC Supplier's detailed product description:
    a. Description including part number, circuit board revision number, firmware revision number
    b. Circuit design block diagram
    c. Photograph of a completed Meter and NIC
    d. Performance Specifications of Meter
    e. Detailed list of Meter and NIC events to include fatal, diagnostic, informational, or any other event type
2. For each electric Meter type, form, and class submitted, a report, authored and signed by the NIC and Meter Supplier that presents the nature and results of the regression tests, and that confirms all of the necessary tests have been completed, and that the NIC and Meter Supplier are satisfied that the NIC together with Supplier's electric Meter will perform in compliance with Supplier's specifications and the requirements stated herein.
3. For each electric Meter, evidence of compliance to FCC, IEEE, OSHA, and ICNIRP RF safety standards while operating in a dual band NAN/HAN mode.
4. Electric Meter, measured azimuth and elevation antenna radiation patterns for horizontal and vertical polarization taken at ~915 MHz. Measurements must be taken under the condition of co-operation of the HAN radio, and when mounted on a metallic electrical enclosure in a manner that is typical for home or industrial installations, as the case may be.
5. Electric Meter, measured azimuth and elevation antenna radiation patterns for horizontal and vertical polarization taken in the 2.4 GHz ZigBee band, or subsequent frequency used for HAN. Measurements must be taken under the condition of co-operation of the Wi-SUN radio, and when mounted on a metallic electrical enclosure in a manner that is typical for home or industrial installations, as the case may be.

6. Documents that outline detailed description, including sensor types used, of the mathematical algorithms and theoretical accuracy and precision that are used to calculate power factor.
7. Detailed test results for internal service switch for Class 200 and Class 320 Meters.
8. Electric Meter Supplier's product description sheet for each Meter type, form, and class that is proposed to be supplied, including no less than:
    a. List of supported functional features
    b. List of data elements available
    c. Technical specifications
    d. Performance specifications: speed, accuracy and precision
    e. ANSI C12 compliance data
    f. Physical dimensions
    g. Security compliance
    h. NEC compliance reports
9. Provide documentation related to item 1.4.9 above on use of batteries.
10. Provide AMI Meter technology roadmap.
11. Provide documentation related to various power factor calculation methodologies as it relates to items in Section 6.3.11.8 and 7.3.11.8.

3 Business Terms and Conditions

3.1 Additional Business Terms and Conditions/Pricing

In addition to any Business related Terms and Conditions and other legal/business matters outlined in attachments to this RFP, the following conditions are appended:

1. Suppliers are requested to outline the value-added services (above and beyond those outlined within this RFP), that Supplier's organization will bring to Company for this project at no additional cost to Company.
2. Suppliers must outline the cost take-out guarantee which Supplier's company will provide to Company over the life of this Agreement. Please provide examples and formula for tracking.
3. Suppliers are required to review and accept the General Conditions for Major Supply Agreement document. Supplier may provide exceptions on the document and submit, as an attachment, back to Company for review. Note that exceptions will be weighted and may preclude Supplier's company from further engagement in the sourcing process.
4. Suppliers will provide a high-level overview of what the market is currently tracking as success metrics utilized to gauge the success of deployment projects of this scope (please include economic and technical considerations). Supplier will be expected to provide success tracking dashboards for reporting purposes if awarded this business.
5. Suppliers are required to inform Company in writing of any foreign nationals, including subcontractors, who will work-on or provide advice concerning the contents of this RFP/project and its outcomes.
6. Company shall require advanced engineering change notification for all hardware and firmware changes. Changes should include risk/impact assessment.

7. Supplier shall notify Company of any reliability/failure causes known by Supplier and attributed to their product.
8. Company shall on an annual basis review Supplier roadmap to ensure alignment with Company goals and expectations.
9. Meter handling and installation personnel in NSPM and NSPW shall be International Brotherhood of Electrical Workers (IBEW)or other Union represented.

3.2 Supplier Support Options for AMR to AMI Transition

1. During deployment of Company's AMI, NSP Minnesota and NSP Wisconsin Operating Companies will transition from an AMR technology utilizing a managed services business model to a Company-owned and operated AMI environment. What would you, as the Meter Supplier and/or Meter exchange provider, offer or provide to enable Company to realize customer satisfaction, meter reading and billing continuity, and efficiencies and reductions in transitional operating costs? Please attach Supplier's plan as a standalone exhibit.

3.3 Executive Level Support

1. Suppliers are required to provide a statement indicating the level of corporate commitment to which Supplier is undertaking. Indicate no less than:
    a. Statement of commitment to Company articulating the key elements where executive commitment brings value to Company's Projects.
    b. Names and positions of executives who represent the commitment.
    c. Manner in which executive level support is applied to Supplier's customers, specifically to Company and to Supplier's internal resources.
    d. Manner in which Executive Level Support is executed where it relates to Supplier's own hierarchy of internal resources.

3.4 Required Corporate Information/Supplier Profile

1. Suppliers are required to submit corporate profile related information as follows:
    a. Supplier legal name
    b. Supplier contact information: phone, fax, email, websites
    c. Postal mail address of business headquarters and field offices
    d. Supplier names, including international, of organizations that sell and/or resell Supplier equipment and services
    e. Dunn and Bradstreet #, ABA#
    f. W9 detail, invoice remittance, and banking information
    g. Diversity certification
    h. Corporate history since inception
    i. Corporate mandate including:
        i. Mission
        ii. Business sectors in which Supplier is operating (water, gas, electric, smart cities, etc.)
        iii. Percentage of revenue generated by electric/gas utility markets in past three (3) years
        iv. Description of projects taken on in last ten (10) years that are similar, including:
            a. Exact system installation and generation as proposed for this RFP
            b. US dollar value of the project
            c. Nature of the project (Metering, DA, Smart Cities, etc.)
            d. Customer reference: names, email address, and phone number

e. Project scope and scale compared to Company's

3.5 Obligations of Company

3.5.1 General Obligations

Company will:

1. Be reasonably available for questions and meetings in a timely manner during normal business hours.
2. Provide contact list, including a Project/Program Manager single-point-of-contact for Company's Meter organization, of Company managed project resources and stakeholders.
3. Coordinate and provide required security clearances and/or escorts to access the site and facilities for completion of the services described in this RFP within Company's standard security response times. Unescorted Access security clearance times may average between 2-4 weeks, and Supplier shall plan accordingly.
4. Execute according to the agreed-upon plans at hand-off/interface points, including the completion of material responsibilities assigned to Company in any SoW that results from this RFP.
5. Assist Supplier in discussions with any third party that Company requires Supplier to manage within the scope of the project, and authorize Supplier to manage and direct such third parties on Company's behalf, if necessary.
6. Reserve the right to witness and inspect the project work at any time.

3.5.2 Obligations Regarding Project Management

Company will:

1. Provide the high-level project schedule.
2. Designate a Project Manager.
3. Provide site documentation, drawings, and master records (if available).
4. Assist Supplier in the creation, distribution, and adherence of an overall project schedule.
5. Take reasonable steps to execute and deliver on required tasks in a timely manner.

3.5.3 Obligations Concerning Electric Meter Deployment

Company will:

1. Use an electronic work order system, or functional equivalent, that collects barcode data and GPS coordinates for each location where Meters and mesh network transition equipment is installed. Supplier can offer alternative use of own work order management system. If alternative Supplier work order management system is proposed, Supplier shall provide detailed operational description and integration to Company business systems requirements.
2. Following training by Supplier, perform all field investigations and remediation of AMI Meters as applicable.
3. Complete all tasks necessary to inventory and warehouse Meters where applicable.

3.5.4 Obligations Concerning Back Office Setup

1. Where it is determined to be necessary for support and maintenance requirements, establish a business-to-business (B2B) and/or virtual private network (VPN) connection from Company back office to Supplier back office systems environment. Each Party shall pay for its cost to set up its end of B2B/VPN connection(s).

3.6 Obligations of Supplier

1. Notwithstanding the details of Supplier and Company obligations stated herein, Supplier shall state the obligations that are necessary for Company to accept for Supplier to fulfil its obligations under this RFP. The statement of Company obligations shall:

    a. Be in the form of a list of resources required by role and responsibilities.
    b. Indicate the timeline that is required for the requirement to be completed by Company.
    c. Include any equipment to be supplied by Company or by any third party.
    d. Include any services to be supplied by Company or by any third party.
    e. Include any additional commitments required from Company to deliver.

2. All documentation supplied or submitted to Company shall be in the form of MS Office 2010 formats, unless otherwise approved by Company.

3. Supplier shall assign and provide a secure de-militarized zone (DMZ) where the product upgrades/patches, etc. are downloaded and applied.

3.7 Obligations of Supplier Project Manager for Optional Electric Meter Installation Services

Where Supplier is authorized to carry out the optional AMI Meter installations, as specified in Section 8, Supplier's Project Manager shall at least perform the following functions:

1. Coordinate with Company Network, Head-end, and Meter Deployment Managers, and third-party Integration Project Managers, to identify and manage project dependencies.
2. Participate with Supplier Delivery Manager and with other AGIS teams on cross-program activities, including dependencies, risk mitigation and issue management, problem solving, optimizing schedules to meet milestone dates, and testing and defect resolution.
3. Be responsible for leading Company, Supplier, Meter Supplier, and third-party Contractor activities diligently toward project success against Meter deployment scope, performance, and schedule and budget metrics.
4. Be responsible in securing cross-docking facilities to support Meter deployment.
5. Ensure project resources comply with Company's onboarding process.
6. Lead a project kickoff meeting in Denver, Colorado. Supplier shall use the session as an opportunity to gather detailed project requirements, and to gain a full and detailed understanding of the project scope. Company's Network Project Manager, Head-end Project Manager, Supplier Delivery Manager, and installation Contractor representatives shall attend the kickoff meeting. At, and associated with, the kickoff meeting:
    a. Ensure all Company onboarding, Company training, and security screening processes are followed.
    b. Ensure Company safety performance standards are followed or exceeded.
    c. Develop details of the project scope, WBS, and schedule.
    d. Document assumptions, constraints, and dependencies.
    e. Commence details of gathering Meter deployment requirements.
    f. Finalize the Meter installation plan.
7. Develop an initial formulation of installation requirements that are in conformance to Meter Installation details contained herein.
8. Act in the role of single point of Meter deployment contact (SPOC) on behalf of Supplier project team.
9. Coordinate project activities from the initial kick-off meeting through delivery of all Agreement elements, as well as any tasks mutually agreed to through a documented change order process, until final acceptance.
10. Under oversight of Company's Business/Meter Project Manager, direct the project activities by way of assigning tasks and responsibilities and monitoring project progress and performance against task completion status, acceptability of performance, and project milestones.

11. Prepare and issue weekly progress status reports, which are first approved by Company Project Manager, and lead project status meetings by telephone or in person following Company AGIS reporting mechanism.
12. Maintain and distribute all documentation by way of email, or by electronic means determined by Supplier and Company to be most efficient and in the interest of both parties.
13. Proactively identify, document, communicate, and mitigate risks and issues. Report deficiencies and concerns proactively on an ongoing basis.
14. Coordinate with Company Meter Deployment Project Manager on Meter first article testing (FAT) process, associated training, and acceptance testing of new Meter shipments.
15. Coordinate with Company Meter Deployment Manager on the delivery of production Meters between Meter manufacturer and Company Meter Deployment Project Manager.
16. Where Supplier's Project Manager is directing or participating in the direction of work for which there are components of work attributable to Company, they shall be carried out through a process in which the work assignment is initiated, carried out, and monitored through Company's Project Manager.
17. Review the Contractor responsibilities with Supplier and Agreement with Company Meter Deployment Project Manager.
18. Lead planning and execution of Supplier project activities from the initial kick-off meeting through delivery of all contract elements, as well as any tasks mutually agreed to through a documented change order process, until final acceptance. This includes project status, change control, scope, risk, communication, schedule, issue, budget, and deliverable management for activities as defined in the Installation plan.
19. Prepare and maintain the project plan which lists the activities, tasks, assignments, effort, dependencies, and milestones for performance of the Installation scope.
20. Lead weekly project status meetings. Schedule additional meetings as needed.
21. Prepare and submit weekly status reports, in format provided by Company, to Company Distribution Business Operations/Meter Project Manager.
22. Coordinate and manage the activities and facilities of Supplier and Contractor project personnel.
23. Direct the project activities by way of assigning tasks and responsibilities and monitoring project progress and performance against task completion status, acceptability of performance, and project milestones.
24. Initiate and lead engagement with Company Distribution Business Operations/Meter Project Manager to address and resolve deviations from the project plan.
25. Maintain project communications with Company Distribution Business Operations/Meter Project Manager.
26. Participate with Client Delivery Manager and with other AGIS teams on cross-program activities, including dependencies, risk mitigation and issue management, problem solving, optimizing schedules to meet milestone dates, and testing and defect resolution.
27. Coordinate the cross-docking, installation, and disposal of meters as specified herein.
28. Lead development of training materials.
29. Lead all testing phases and take accountability for defect resolution within the terms outlined herein.
30. Supplier will participate in and support end-to-end testing as defined by Company in the AGIS initiative, including writing and running of test scripts in conjuction with Itron Networked Solutions, as appropriate, and defect fixing as needed.

4 General Security Requirements

4.1 Overview

1. As Company adds intelligence to the electric grid, each part of the grid must be evaluated for security risk. Risks must be mitigated to ensure the reliable delivery of electricity to our

customers. Company has developed principles, strategies, and requirements to assist in identifying and mitigating risks.

2. Suppliers are required to comply with all of the principles, strategies, and requirements outlined herein.
3. Suppliers are required to meet the security requirements for Meters set out in Sections 6 and 7 herein.

4.2 Company Security Strategies

1. Conforms to industry standards and best practices as pertains to Meter technology.
2. Support and utilize secure network communication protocols (e.g. HTTPS, SFTP, SSH, SSL, TLS, etc).
3. Leverages strong authentication and authorization model (role-based access and role-based activity to individual Meters).
4. Support a deny-by-default approach to AMI component configuration.
5. No reliance on non-secure protocols/ports (e.g., telnet).
6. Disable all unnecessary and unused protocols/ports.
7. Support and integrate with centralized system configuration, change management, and monitoring systems.
8. System must be capable of security event logging capabilities that can be utilized and regularly reviewed.
9. Unauthorized access attempts shall be logged with alerts presented to the appropriate parties.

4.3 Company General Security Requirements

If Supplier has access to any Company or client confidential information, please describe how confidentiality is going to be maintained, including how information is retained and/or disposed of at designated times.

1. The corporate software maintenance process shall be followed for upgrades and patches.
2. Vulnerability scans are to be performed for equipment or product before it is put into both test and production.
3. Product shall not use unsupported open source code or operating systems.
4. Product shall have application security testing performed by Supplier and the results shall be shared with Company.
5. Supplier shall follow best practices in their coding by utilizing secure application development methodologies such as those recommended by the Open Web Application Security Project (OWASP).
6. All product testing shall be performed in non-production environments.
7. All security logs shall be captured by a centralized logging device, such as Security Information and Event Management (SIEM).
8. Data encryption shall be utilized for both data-at-rest and data-in-motion.
9. Encryption algorithms shall be of sufficient strength with equivalency of AES-256.
10. Multi-factor authentication shall be utilized.

11. AMI Head-end user access shall utilize role-based security, enabling access to be assigned by, for example, functionality, geographic area(s), asset grouping, and business areas.
12. Active Directory shall be used for user and service authentication.
13. Credentials are required to be stored in encrypted form.
14. Secure messaging shall be utilized whenever technically feasible such as SFTP.
15. If mobile technology is available, the application shall be compatible with Mobile Device Management Systems.
16. Appropriate firewall rules shall be used.
17. Intrusion prevention technology shall be utilized.
18. Only secure TCP/IP protocols shall be utilized.
19. Least functionality principles shall be practiced.
20. Least Privilege principles shall be practiced.
21. Defense-in-depth posture shall be practiced.
22. Zero-Trust Networking shall be practiced.
23. Tightly-controlled access shall be practiced across all network layers.
24. AMI Head-end shall support 8-character password with complexity (upper and lower case alpha, numeric, special characters).
25. AMI Head-end application shall not need to store Personal Identifiable Information (PII), but if it does, the application shall ensure the security and privacy of such information.
26. Supplier shall notify Company immediately in writing and electronically when security vulnerability is identified.
27. A patch shall be released to resolve firmware or security vulnerabilities within a Company-specified timeframe depending on the criticality of the security risk.

4.4 General Security Questions

Supplier will need to provide answers for each of the questions listed below. These questions will also be included in Company's Vendor Risk Assessments (VRA).

1. Does the vendor have a formal/documented Information Security program that includes the following elements?
   - Information security policies and standards
   - Information security governance function
   - Training and/or awareness program
2. Does the vendor have the following processes in place?
   - Information security incident management
   - Change management
   - Computing system patch management
3. Does the vendor have the following controls in place in its Information Technology, firmware development, and manufacturing environments?
   - Network IPS/IDS
   - Firewalls
   - Malware protection
4. Has the vendor experienced any Information Security incident/data breach during the past twelve (12) months? If Yes, please provide a summary report.

5. Is the vendor aware of any critical vulnerability(ies) in its computing environment/product?
6. If **Yes**, will the vulnerability(ies) be fully remediated prior to the start of the proposed engagement with Xcel Energy?
7. Does the vendor perform periodic reviews of access rights to systems, applications, databases, and network devices?
8. Does the vendor limit access to its systems and information technology assets to those with a business need for access?
9. Does the vendor anticipate the need to have unescorted physical access to any Xcel Energy critical assets (e.g., data centers, substations)?
10. Does the vendor conduct pre-employment background checks for all of its workers, including the topics of prior employment, criminal history, credit history, academic history, and drug screening (unless prohibited by law)?
11. Does the vendor have a formal/documented Business Continuity Program that includes the following elements?
    - Business Continuity and/or Disaster Recovery policies, standards, and plans.

5 General Requirements for All Electric AMI Meters

5.1 Technology Compatibility

1. Meters
    a. Meter must maintain seamless communication between Meters and NICs (Network Interface Cards).
    b. Meter Supplier must maintain a written agreement concerning the adoption, deployment, and use of standards with the NIC Supplier.
2. Application
    a. Supplier's Application that allows Meter access must be deployed on an operating system that is the CORE Standard established by Company (please review Appendix 2 for list of Enterprise Technology Standards).
    b. Application must access Meter through a USB port (e.g. from a user's laptop) through an optical cable physically plugged to Meter (Wi-Fi and Bluetooth are also options for local connectivity, per Section 5.11.6).

5.2 Managing the Lifecycle of Standards (Changes, Updates, Depreciation, etc.)

1. Supplier shall not implement any product changes unless:
    a. Company and Supplier consult concerning any financial, technical, and/or operational impacts, in the form of meetings of qualified individuals.
    b. The amended product capabilities, performance, and security features are provided by Supplier in writing to Company well-in-advance and accepted in writing by Company.
    c. An acceptable implementation work plan is established and agreed upon by Company.
    d. Supplier completes any testing required to confirm continued stability at a location that is not service impacting.
2. Where Supplier requires adoption of any new Standard and/or upgrade of a Standard, even if such an upgrade is offered at no cost, and such action implies any new consequential costs to Company, Supplier shall:
    a. Pay such costs unless agreed to otherwise by Company.
    b. Guarantee that such changes are not service-impacting in any negative way.

5.3 Evolutionary Equipment Upgrades

1. Regardless of any product evolutionary improvements, Supplier shall maintain the capacity to supply products of equal function to those supplied to Company, and interchangeable without any modification, for a period of twenty (20) years, commencing on the date of execution of the Major Supply Agreement. This includes maintaining capability for the Meter products to seamlessly interface to the most current generation NIC in use by Company.
2. Throughout the project term, where Supplier upgrades hardware and/or firmware and/or software, for the purpose of improvement, feature enhancement, etc., and ceases to manufacture and/or develop the existing product, Supplier shall:
   a. Notify the change expectation to Company no less than twelve (12) months prior to cessation of Supplier's delivery of existing product or product set.
   b. Identify revision numbers.
   c. Provide a written description of the change, and a statement of impact of the change, on Company operation.
   d. Not increase the price of the product.
   e. Continue to supply products of like function without supply interruption.
   f. Revise, at Supplier cost, any processes or documentation that changes as a result of the upgrade.
3. Where Supplier offers a new feature offered as an enhancement, Company may elect to take-up the incremental feature under the following conditions:
   a. The feature is fully characterized and explained to Company.
   b. Company, following a period of testing and assessment determines whether the enhancement is acceptable for production.
   c. The offered or negotiated incremental price is acceptable to Company.
4. Throughout the project term, where Supplier upgrades hardware and/or firmware and or/software, for the purpose of improvement, feature enhancement, Supplier shall:
   a. Notify Company within sixty (60) days.
   b. Provide Company copies of software and hardware firmware upgrades.
   c. Identify revision numbers.
   d. Provide a written description of the change, and a statement of impact of the change, on Company operations.

5.4 General Meter Qualification Testing Requirements

1. Company will designate a meter engineering test coordinator.
2. Supplier is required to supply to Company a quantity of twenty (20) electric Meters of each type and form to be FAT tested at a date to be coordinated with the Meter Test Coordinator.
3. Supplier is required to appoint one or more Subject Matter Expert(s) (SME) who will interface with Company's engineering test coordinator and Company SMEs for purposes of designing and carrying out the testing program.
4. Supplier's SME shall work with Company to provide/assist Company with opportunities to explore system features and capabilities in Company's AMI lab and in hands-on settings.
5. The actual testing events are expected to consist of, but not be limited to:
   a. Metrology testing at Company Material Distribution Center (MDC) location for each Meter type.

b. AMI-specific functionality and performance testing at locations determined by Company.

c. Performance testing with respect to access to mesh networking.

d. Outdoor Meter testing.

6. Company evaluators will, independently, carry out AMI Meter testing as a means to quantify, qualify, validate, and confirm Supplier's detailed point-by-point response to the RFP and any purported features and/or specifications that Supplier offers or has offered.

7. Company will document the testing undertaken and provide a detailed report of tests and results. Supplier will be provided with opportunity to inspect and review testing results from their individual Meters. Where Supplier disagrees with any result, Supplier may propose changes or adjustments to the testing methodology in consultation with Company. Where it is determined that a testing method requires adjustment or change, Company may, at its election, carry out a repeat measurement on competing products.

8. Where Supplier develops and/or requests any form of testing that is in addition to that necessary to validate and/or test any specifications or features stated herein, Company reserves the right to carry out the developed and/or requested test on any competing Meter, at its election.

9. All communications will be subject to a Non-Disclosure Agreement (NDA). Company will not conduct any form of validation testing without agreed upon NDAs in place.

10. Company will be testing all Meter Suppliers' products sequentially.

11. Demonstrations are expected to take place at Company's location in Denver, Colorado, in an assigned controlled environment. Suppliers will be provided with secured access to the setup space at one of the following locations :

    a. MDC – 9500 Brighton, Henderson, CO 80640.

    b. HomeSmart – 6981 South Quentin Street, Suite A, Centennial, CO 80112-3939.

5.5 First Article Testing (FAT) Requirements

1. For all AMI Meters supplied to Company, Company will conduct FAT (First Article Testing) testing. The following conditions apply:

    a. For Meters that fail FAT, Company shall communicate to Supplier reasons for the failure. Supplier shall immediately correct deficiencies, and within one (1) week send corrected production type FAT Meters to Company for FAT.
    b. On any new Meter model or form, Supplier shall provide Company with at least four (4) production samples for each model type and Form for FAT testing. FAT Meters must be provided to Company within two (2) weeks of placing the order for the Meters. Manufacturing of production samples will not begin until Company has completed FAT testing and issued approvals to Supplier.
    c. FAT will, at a minimum, encompass the following items:

        i. Physical construction
        ii. Accuracy and dielectric testing
        iii. Nameplate label
        iv. Metrology
        v. Display
        vi. Communication Module (NIC)
        vii. Programming
        viii. Other (KYZ operation, service switch operation, LP verification)

2. Supplier shall maintain a real-time secure database, with an exportable format for Company's inventory management system from which Company may access information on Meter inventory components, holding no less than the following information:

    a. Meter model type and model number
    b. Catalog number
    c. Hardware version number(s)
    d. Meter serial number
    e. Firmware load rev number
    f. Date of manufacture
    g. Date tested
    h. Name of testing person
    i. FAT test document reference
    j. Date shipped
    k. Ship-to addressing
    l. Security keys via appropriate certificate management methods

3. Supplier shall not ship any Meters that have not complied with Company FAT test regimen.
4. Meter supply chain security requirement to include, but not limited to:

    a. Meters are to be properly security tested and hardened to Company's security standard (to be established in a Meter security workshop) prior to shipment.
    b. From manufacturing to shipment of Meter, a secure and documented chain of custody process shall be established to ensure the security and operational integrity of the Meter once deployed on Company's FAN.
    c. Meter shall be shipped with a tamper detection seal to ensure the device has not been tampered with prior to delivery to Company.

5. All shipments greater than three (3) Meters will be sample tested for accuracy and Meter functionality. Meters not meeting Company accuracy requirements and/or functionality requirements will be shipped back to Supplier, for correction, at cost to Supplier. A root cause analysis report shall be provided by Supplier for each Meter returned to Supplier and tested within thirty (30) business days from the date the returned Meter is received at Supplier.
6. Company will use an AQL of 0.40% for full load (FL) light load (LL) and power factor (PF) and an accuracy requirement of +/- 0.5% for FL, LL, and PF in analyzing the samples. Company will follow the requirements in ANSI/ASQC Z1.9-2003, inspection level II, Table A-2 and Table B-3 in analyzing the samples for accuracy. In addition a sample Meter functionality test will be conducted using ANSI/ASQC Standard Z1.4-2003, reduced inspection, inspection level II, Table I and Table II-C using an AQL of 1.0. For each sample tested any one of the following is counted as one non-conformance: service disconnect not fully functional when operated (open/close) via the network, AMI communications not working properly, display not visible, incorrect programming and significant error message.
7. Supplier shall support Company in setting up Meter hardware in Company lab environment for AMI testing.

5.6 Meter Technical Requirements

1. All Meters, with the exception of 2S and 12S network Meters, must be multi-ranging voltage Meters from 120 – 480V.
2. All Meters to have a polycarbonate cover with magnetized cable-free Opticom Port with a ¼ turn Reset Mechanism for resetting demand.

3. KYZ wiring should exit the rear of the Meter. No pigtails are required for KYZ wiring for Form 9S single KYZ Meters. Internal Meter KYZ wiring should be connected to output terminals on the back of the Meter for this Form only.

5.7 Meter Shipment Requirements

1. All Meters to be accurately tested prior to shipment. Test results (FL, LL, and PF) to be formatted and delivered to Company as specified below in Test Results.
2. All Meters to be programmed at the factory with a Company-supplied program.
3. All Meters to be shipped with two (2) replacement labels attached to the Meter cover. The replacement labels should have the AEP bar code and lettering on each label.
4. Meters in each shipment shall have serial numbers consecutively numbered with no more than nine (9) numeric characters.
5. Nameplates and box labels must be approved by Company for any new model or Meter types.
6. For all Meters with Network Interface Cards (NIC), the cost for installing the NIC should be included in the Meter price. Supplier to be responsible for scheduling shipment of the NIC to meet Meter manufacturing schedule.

5.8 Electric Meter Nameplate Requirements

1. All nameplates shall have an AEP bar code approved by Company.
2. Two nameplate barcode stickers must be affixed to the back of each Meter.
3. All nameplates shall be inclusive of Company name and logo, and shall be approved by Company prior to manufacture.

5.9 Box Label Requirements

1. All boxes are to be arranged on a pallet so that the box labels are visible in a way that allows the box labels to be read and scanned.
2. All containers, including shipping boxes and packaging, shall include the following information on labels:

   a. Name of Company in bold lettering
   b. Meter serial number and AEP bar code for each Meter in box
   c. Beginning and ending barcodes of pallet contents
   d. Quantity of Meters in box
   e. Manufacturer name, address, and assigned Meter catalog/model number
   f. Purchase order (PO) number
   g. Sales order number
   h. Date of shipment
   i. Meter model number
   j. Company material
   k. Line item number and release number
   l. Quantity in shipment
   m. Number of units in each pallet
   n. Pallet number box is located in
   o. Meter type/model
   p. Meter Form
   q. Meter number of wires
   r. Meter Test Amperes (TA)

s. Meter class
t. Meter frequency in Hertz
u. Item number

5.10 Supplier Test Results

1. FL, LL, and PF test results to be emailed to Company within five (5) days prior to Meter shipment. Test results to be emailed to: dlMeterdata@xcelenergy.com.
2. Format for test results per Appendix 5 (Meter Calibration File Format).
3. Meter and NIC marriage or integration information.

5.11 Optional AMI Meter Functional Features

5.11.1 Requirements for Voltage Phase Identification

1. AMI Meters shall enable, internally and/or by way of third party software systems operating at the AMI Head-end, a means to identify and communicate information that identifies Meters, within a specified community, that share a common power systems phase connection.

5.11.2 Requirements for Open Neutral Detection

1. AMI Meters shall enable, internally and/or by way of third party software systems operating at the AMI Head-end, a means to detect, identify, and communicate information that indicates an open neutral fault condition for the individual Meter or group of Meters under study.

5.11.3 Meter Support for Electric Pre-pay

1. All Meters shall be certified to support Electric Pre-pay as specified in ZigBee® Alliance Smart Energy Profile (SEP 2.x) Specification (ZigBee® Document: Smart Energy Profile 2, 13-0200-00, April 2013 and revisions).

5.11.4 Meter Support for Total Voltage Harmonic Distortion

1. Meters shall be equipped to measure and report on Total Voltage Harmonic Distortion (TVHD) in compliance to IEEE 519-2014.
2. Supplier shall provide a functional block diagram that illustrates the quantity and type of sensors that are provided in the Meter for the purpose of sensing voltage and current parameters, the salient circuitry that is used to sense and calculate TVHD.
3. Supplier shall indicate the mathematical algorithm and manner in which TVHD is calculated and state the specified accuracy and precision.
4. Supplier shall confirm that TVHD reporting is wholly immune to the effects of radio frequency emissions arising from the use of the third party NIC in both the 900MHz and 2.4 GHz bands including any related spurious components.
5. TVHD shall be carried out on a continuous basis and be sampled at a rate that:
   a. Is capable of reporting computed results at a rate of 60 Hz.
   b. Guarantees a 3dB bandwidth of 20,000 Hz for any sampled line/node.

5.11.5 Expanded Meter Functionality

1. Four Quadrant Meter Measurements

5.11.6 Wi-Fi and Bluetooth Meter Connectivity

1. Meters shall have the option of local connectivity via Wi-Fi and/or Bluetooth. This would enable local Meter access for troubleshooting and other activities.

5.11.7 Load Signature Analysis

1. AMI Meters shall enable, internally or by way of third party, a means to identify loads by signature and communicate this information via the NIC.

6 AMI Electric Residential Meter Requirements

6.1 Non Functional Requirements

1. Supplier's final assembled products shall have wholly integrated third party Gen 5 series NIC devices.
2. Supplier's products shall perform up to the:
    a. Specifications stated by Company
    b. Requirements drafted by Company

6.2 Detailed Security Requirements for Every AMI Electric Residential Meter Supplied

1. Security requirements shall apply to all AMI Meter types that are deployed on Company AMI network.
2. Encryption of data stored in Meter memory, and in the transfer from CPU to memory, shall be required.
3. Meter shall lock/disable chip diagnostic and programming ports (JTAG).
4. Provisions for secure local access shall be made available through the network or secure direct connection to the Meter (i.e. optical port).
5. Meter (and Field Tool) shall include cryptographic secured authorization/authentication for local Meter data download attempts.
6. NIC shall be integrated with Meter under the cover.
7. Meter shall log all login attempts to its indelible log and support a lockout for a configurable amount of time upon repeated invalid attempts. Supplier shall provide list of other security events that the system is capable of logging. Additionally, Meters must send log alerts to Company for further analysis and response.
8. Meter shall support, at minimum, symmetric key lengths of 128 bits.
9. Supplier shall provide a detailed cryptographic key management description explaining how cryptographic material is provisioned, used, stored, and deleted within the system.
10. NIC shall explicitly deny any information flow based on illegal message structure. NIC shall have provisions to detect and thwart a message replay attack e.g. as per ANSI C12.22.
11. Meter shall employ mechanisms that ensure device integrity from external tamper and compromise.
12. Meter shall comply with cyber security programs based on good industry standards according to NIST SP800-53,SP800-82 and NISTIR 7628.
13. Meter shall supply a Meter-to-Head-end cryptographic solution which assures the confidentiality of Meter's data while in transit.
14. Meter shall supply mechanisms which allow for secure device authentication, registration, and revocation.
15. Meter shall supply cryptographic mechanisms or materials which allow for unique device identification, authentication, and communications.

16. Meter shall supply cryptographic mechanisms or materials which allow for group access.
17. Meter shall supply mechanisms which audit, store, and transfer to SIEM all security related events, including all access and modifications events within the system.
18. Meter shall supply a security audit store, which includes date and time of event, type of event, user identity, and the outcome (success or failure) of event, and transfer the event to Company's SIEM.

6.3 Meter Functional and Performance Related Requirements

6.3.1 Compliance to Company Specifications

1. All Meters shall:
   a. Meet or exceed Supplier's technical and functional specifications over the twenty (20) year lifetime of the product.
   b. Meet or exceed the electric Meter requirements herein.
   c. Include Itron NIC device in final assembly of Meter.

6.3.2 Interoperability and Standards

1. Meters shall be built to ANSI C12 standards.
2. Meters shall have an interface capable of supporting multiple communication modules furnished by multiple potential Suppliers. The communications modules will reside under the Meter cover and collectively support the functional and non-functional requirements as specified herein. This includes making accessible all metering data to the communication interface for remote access.
3. The NIC furnished by potential Suppliers shall have an interface capability for the life of the Meter.
4. There shall be transparent IP routing to the Meters. Meters and control devices shall be configurable to support either or both IPv-4 and IPv-6 communication.
5. All electric Meters shall have a 0.5% or better accuracy performance.

Please refer to Appendix 2 at the end of this document for Enterprise Technology Standards.

6.3.3 Meter Feature Requirements

1. Meters shall be equipped with temperature sensors capable of measuring and logging Meter temperature for detection of hot sockets.
2. Meter shall be capable of reporting internal temperature as an interval channel or a temperature alarm as specified below:
   a. Meter shall be capable of reporting internal temperature for purposes of hot socket detection. When equipped with an internal service switch, Meters shall be capable of remote disconnect initiated by back office function.
   b. Meter shall be capable of generating an alarm when a configured internal temperature is exceeded. When equipped with a service disconnect switch, Meters shall be capable of remote disconnect initiated by back office function.
3. Meters shall be equipped with tilt/motion sensors.
4. Tilt/motion shall be captured/processed at power down by motion sensors to differentiate removal from normal outage.
5. Meter internal timekeeping clocks shall be governed by a disciplined clock analogous to that used by the Network Time Protocol (NTP) in which the clock speed, rather than the clock setting, is adjusted to effect time error corrections. In this case the Meter clock should be disciplined against the clock which governs the anticipated mesh network. With a disciplined clock there will never be discontinuities in the time record of, for example, load profile records which would

produce short and long intervals except in the possible case of power-up operations when the clock is initially set. Reference the RFC 1129 NTP algorithms described in a 1989 paper at URL: https://www.ietf.org/rfc/rfc1129.pdf. The case of a GPS disciplined clock is described in a Wiki article at URL: https://en.wikipedia.org/wiki/GPS_disciplined_oscillator.

6. Transformer rated Meters shall optionally allow Company to include potential and current ratios in transmitted Metered data.
7. Meter shall be able to self-register on the AMI network and communicate to the field network setup tool whether or not all aspects of the Meter and its communication with the AMI system are operating properly.
8. Load profile data shall be recorded and date/time stamped at the end of each interval. The date and time stamping of load profile data shall be consistent with ANSI C12.19.
9. Meter shall be configurable to support delivered, received, net, and absolute power at the Meter.
10. Meter shall support a configurable flag on detected reverse power flow. This flag would send an alarm when reverse power flow is detected. Parameters would include recognizing reverse flow at a configurable level (watts to kilowatts) over a configurable interval (five seconds to one hour) to prevent false triggering.
11. Meter shall support a network time synchronization of one (1) second or better and be able to time stamp its voltage peak to an accuracy of one (1) second. If an optional Phase Detection feature is deployed which requires greater time accuracy and resolution, Meter shall support such increased time resolution.
12. Meter load profile interval shall be configurable from one (1) minute to twenty four (24) hours. (Options to include one (1) minute, two (2) minutes, five (5) minutes, ten (10) minutes, fifteen (15) minutes, thirty (30) minutes, sixty (60) minutes, one (1) day).
13. Both Meters and communication devices must be capable of hard resets to factory default conditions by local means without shipping back to Supplier.
14. To facilitate Meter processing and installation, Meters and NICs shall be uniquely identifiable by both bar coding and electronic communication. Meter label shall conform to Company standard template which will be provided prior to manufacture date and confirmed during First Article testing.
15. Both Meter and communication infrastructure shall support remote desktop access to Meter using Supplier's native configuration software (e.g., Metercat, PCPro, etc.) over an IPv4 and/or IPv6 connection. This remote access shall be possible in equivalent terms through the Meter's optical port if so equipped, through the field area mesh network, and through the enterprise network from, for example, a Meter technician's desktop.
16. Each Meter shall have the capability to backup and restore.
17. Meters shall support independent demand register times so that meters can simultenously support multiple demand intervals e.g. 5, 15, 30 and 60 minutes.

6.3.4 Upgradeability and Configurability

1. Each Meter subsystem (e.g. metrology, register, Meter configuration [Program], HAN (if equipped), and Network Interface [NIC]) shall be upgradeable by secure remote download.
2. Each Meter subsystem shall have sufficient memory to support, at minimum, an anticipated 2x increase in memory requirements due to future enhancements and/or bug fixes.
3. Each Meter subsystem shall have sufficient memory to maintain operating, previous, and in-transit images of their respective firmware and shall support rollback to the previous successful image in the event of an error in either transmission or configuration that might require such rollback.

4. Residential Meters, if equipped with a service switch, shall have the ability to limit load/service. The load limit shall be configurable such that multiple configurable steps (e.g. ninety percent (90%) of rated capacity, seventy five percent (75%) of rated capacity, etc.) can be configured in the AMI Meter.
5. If bi-directional energy measurement functionality is required to be activated in the Meter, Meter shall be able to be re-programmed remotely over the air. This reprogramming event will be logged in the Meter and sent back to the Head-end immediately.
6. Data sent from Meters shall be configurable as to whether interval data, register data, event data or all data shall be sent during routine or on-demand Meter read requests.
7. Meter shall permit TOU, CPP, and PTR time period to be remotely configurable.
8. Meter shall permit its firmware and programs to be remotely downloadable without loss of register data.
9. Meter shall report failures, e.g. communication failure after reboot, program lock-up, etc., following a software/firmware upgrade within fifteen (15) minutes after start-up of a new program. Reportable failures shall include billing information loss or loss of electric service. Meter failures to report shall be configurable in Meter program.
10. Register Meter functions shall be programmable both remotely and locally.
11. Handling of received energy shall be configurable in the Meter, e.g. sum of delivered and received energy, ignored, net, etc.
12. Meter feature set shall include an indelible logging facility that records all administrative actions, e.g. reconfigurations performed on Meters, and report to the AMI Head-end. Indelible logs shall survive Meter reprogramming and firmware upgrades.

6.3.5 Availability

1. Meter shall continue to record all required data during a communication failure.

6.3.6 Connect, Disconnect, or Limit Service

1. All self-contained residential Meters class 200 (Forms 1S 2S and 12S) and class 320 (Forms 2S and 12S) shall be able to remotely connect/disconnect/limit electric service to customer premises.
2. The service switch shall be rated for at-least 10,000 service disconnect/reconnect operations.
3. Meter shall be able to limit demand served to a customer by a remote utility on-demand request or through utility pre-configured rules (e.g. 90% of rated capacity, 75% of rated capacity, etc.)
4. Meter's disconnect switch shall be capable of inhibiting the close operation when there is voltage on the load side to prevent equipment damage or personal injury.
5. Remote disconnect shall be integrated with Meter rather than a collared solution for Meter types that have been identified as requiring a disconnect switch.
6. Meter shall permit remote changes to the threshold for load limiting from MDM or Head-end. Thresholds shall be configurable.
7. Internal service switch shall have a rating consistent with Meter class rating at 60% lagging power factor.
8. Internal service switch shall close a configurable number of times automatically after a configurable delay if Internal Service Switch trips open because the demand/energy limit is exceeded.
9. Meter shall acknowledge load limit command successful to Head-end.

10. Meter shall acknowledge and communicate open/close status of the internal service switch after operating command is issued and shall be confirmed by Head-end.
11. Internal service switch shall be operable through the optical port and/or through the Field Tool used for Meter installation and maintenance.
12. Meter disconnect event (remote or local) shall not generate a last gasp message.
13. Meter shall record a disconnect event if the switch operates without a command.

6.3.7 Visible Access to Data

1. Meters equipped with an internal service switch shall provide for an external indication of the switch status discernable to a customer or Company employee on site.
2. Meter display shall provide date and time as specified by the utility. The display shall also display and label measured quantities in engineering units.
3. Displayed data shall match stored and transmitted data.
4. Meters shall be capable of displaying registers of all possible Metered data. Displayed data must show associated metrics/unit of measure.
5. Meter display shall include status of FAN communication link.
6. If equipped with Home Area Network (HAN) or Internet of Things (IoT) interface, Meter shall display status of HAN/IoT communication.
7. A visual disk emulator shall be provided on all Meters.
8. Meter shall be able to operate in alternate and test modes and display separately configurable alternate and test mode display sets.
9. Meter shall be placed into alternate and test modes locally. Test mode to have configurable time-out period (reverting to normal mode) and ability to be set to normal mode remotely.
10. Normal and alternate displays to include error and warning conditions.

6.3.8 Demand Response

1. The Meter will not inhibit Company practice that all control and reconfiguration commands sent through the field area network must be confirmed by field devices to the back office within fifteen (15) seconds.

6.3.9 Distributed Generation

1. The Meter shall collect delivered, received, and net cumulative values, as well as interval data as signed (positive or negative) values. Delivered cumulative shall be equal to the sum of delivered intervals, received cumulative shall be equal to the sum of received intervals. Both time duration and energy threshold shall be configurable in seconds.
2. Meter display shall be configurable to display any or all of the measured quantities identified in item 1 above.

6.3.10 Installation and Maintenance

1. NIC in the Meter shall have unique identification for LAN and FAN.
2. Meter shall have an indelible unique serial number over the life of the AMI system.
3. If equipped with HAN/IoT, Meter shall have a unique ID for HAN/IoT communication.
4. Upon installation, Meter shall optionally recognize, as configured by Company, the service type and issue alarm messages for unrecognized services (or abnormal service conditions). Meter shall have functionality that enables it to individually disable service level alarms.

5. Meter shall be able to identify itself to a field network setup tool and provide access to its data and configuration settings at installation time, and later in support of ongoing operations and maintenance activities subject to security authorization.
6. Meter shall perform self-checks and report results to installer field tool, local display, and to the AMI network. Self-checks to include integrity of the HAN/IoT communications card (if present) and AMI network communication card, and ability to communicate with local collector (AMI communication network architecture dependent).
7. Meter shall be capable of communicating with Supplier-supplied Field Tool over the NAN network via the Meter's NIC.
8. Field Communication Tool shall be capable of operating internal service switch and resetting demand.
9. Field tool shall be capable of communicating to Meter using wireless mesh network with at least the same functionality as is offered using shop or desktop tools.

6.3.11 Meter Measurement Capabilities

1. Meter shall provide time-stamped peak demand and energy for all configured time of use periods.
2. On the occurrence of an on-demand interval data read, the Meter shall be capable of sending time stamped any selected or all stored data and other associated register and diagnostic information.
3. Based on company requirements the Meter shall complete a self-read and store the value for each channel register of data.
4. On the occurrence of a scheduled read, the Meter shall be capable of sending time stamped any selected or all stored data and other associated register and diagnostic information.
5. Voltage resolution reported to Head-end shall be 0.1V or better.
6. Power Factor calculations shall include at least the following: average, max, min, coincident, etc.
7. Power Factor calculations shall be have both options for using either the total power factor (real power/apparent power) or by the displacement power factor (cos(θ)) methods.
8. Supplier shall provide detailed description of each of the options available for power factor calculation.
9. Meter shall accommodate a minimum of sixty (60) days of load profile data with five (5) minute intervals for at least four (4) channels of data.
10. Meters shall support TOU and critical peak pricing capabilities: (a) 4 TOU rates, (b) critical peak pricing rate, (c) ability to switch between time zones, (d) ability to switch between Standard Time and Daylight Saving Time, (e) support for four (4) seasons, (f) support advance calendar for at least twenty (20) years, including holidays.
11. Residential Meters shall be configurable to measure both integrated and instantaneous values (linear average over one (1) second) for the following:
    a. kW
    b. kVAr
    c. Voltage
    d. Current
    e. kVA
12. Residential type Meters shall be configurable to provide at least the following register and interval data:

a. kVArh delivered
b. kWh delivered and received
c. Internal Meter temperature and temperature alarm
d. Voltage magnitude and angle
e. Current magnitude and angle
f. kVAh Delivered

13. Residential meters shall have capability for selecting either vectorial or arithmetic methods for calculating KVA delivered and received.

6.3.12 Outage Management

1. Meter shall be capable of sending a message if load side voltage is detected on a disconnected Meter.
2. Meter shall maintain sufficient function for a sufficient amount of time to differentiate between an interruption and a power quality (PQ) event.
3. Meter shall alarm if voltage less than a configurable threshold is detected for a configurable period of time.
4. Meter shall alarm if voltage greater than a configurable threshold is detected for a configurable period of time.
5. Meter shall detect and send a last gasp/tamper alarm to the Head-end. Detection shall be possible after the Meter is removed and before it stops communicating.
6. Meter shall be able to send a last gasp message over the communications network during an interruption or removal.
7. At the system level, Meters shall remain operational after an interruption for a period of time that is sufficient to achieve:
    a. 100% reporting on single meter outage.
    b. 90% of meters reporting on outages of up to 1000 Meters.
    c. 80% of meters reporting on outages of 11 to 100 Meters.
    d. 60% of meters reporting on outages of 101 to 1,000 Meters.
    e. 50% of meters reporting on outages of up to 10,000 Meters.
    f. 30% of meters reporting on outages of 1,001 to 10,000 Meters.
8. Measurements of momentary interruptions, momentary interruption events and sustained interruptions shall be consistent with IEEE Std 1366-2012. In the case where IEE 1366 standard changes, the new definition shall supersede the old.
9. A single momentary interruption event includes all momentary interruptions experienced by Meter within a configurable period (e.g. five (5) minutes, etc.). Service must be restored within a configurable time period (e.g. five (5) minutes) to be classified as a single momentary event.
10. An interruption of less than a configurable time period (e.g. five (5) minutes) shall be considered a momentary interruption and shall be logged by the Meter as a momentary interruption.
11. An interruption of more than a configurable time period (e.g. five (5) minutes) shall be considered a sustained interruption and shall be logged by Meter as a sustained interruption. The sustained interruption includes all the switching events from the initial interruption to full restoration of the sustained interruption event.

12. Data recorded by the AMI Meters will be used to calculate Momentary Average Interruption Frequency Index (MAIFI) and Momentary Average Interruption Frequency Event (MAIFE). MAIFI and MAIFE include all momentary interruptions that are not part of a sustained interruption.
13. A single interruption shall trigger Meter logging.
14. Momentary interruptions shall be reported up to the Head-end with the next scheduled Meter read.
15. The above notwithstanding, power quality event selection shall be possible based on a pick-list of industry accepted power quality events in Meter setup tool in addition to ad-hoc definitions entered at Meter configuration definition.
16. Meters shall log outages and restorations and make data available to Head-end AMI system. This shall include time stamp.

6.3.13 Reliability

1. Supplier shall provide accelerated life testing results for all the system components that substantiate the system's life and that identify top failure causes.
2. Meter must survive and function properly without losing data or programs through repetitive short-term power outage cycles as might be experienced by recloser operations.
3. Meter time clock shall be configurable through the network and shall be accurate with a drift rate of no worse than one (1) minute per year. Meter clock shall be governed by a disciplined clock controlled by the system time using techniques similar to the Internet Network Time Protocol (NTP). Maximum allowable deviation from absolute time is no greater than one (1) second.
4. Meter shall be provisioned with an indelible log to receive event entries.
5. Type of events logged by Meter shall be configurable. Event messages for transmission and priority shall be determined by Company.
6. Meter shall send acknowledgement of a successfully completed or failed electric service connect/disconnect/limit event to the Head-end with latency not to exceed twenty (20) seconds.
7. Meter shall log the date and time stamped establishment of load limit set points.
8. When Meter's rated and configured load limits are exceeded, support for solicited and unsolicited reporting shall be available.
9. Meter shall log all local (and remote) Meter access attempts (configuration, data download, time adjustments, etc.), whether successful or not, and the requester ID. System shall support solicited and unsolicited reporting.
10. Meter shall be able to detect loss of load (greater than a configurable period of time) on the customer side of the Meter that is not related to a remote disconnect, log the event, and send an event message to Head-end. When load is restored, Meter shall log the event.
11. Meter reinstallation events shall be sent to Head-end immediately upon reinstallation along with any unsent tamper events.
12. An event generated when Meter is reinstalled is different from an event generated if Meter is initially installed (provisioned) or re-energized (e.g. after an outage). This is to avoid transmission of useless and confusing information to the enterprise systems because of non-tamper related events.
13. Meter's internal clock shall be synchronized in such a manner that Meter data that includes register and interval data shall not be affected and shall log the event. This requires the use of a disciplined clock governing the Meter as discussed above.

14. Meter shall be able to detect and log communications link failures upon failed communications initiated from Meter.
15. Meter shall be able to send an alarm/event to the Head-end (in the format in which Head-end can receive) when a configurable number of consecutive communications link failures are detected (e.g. three consecutive link failures).
16. Meter NIC shall be able to periodically record the communication signal strength and report it back to the Head-end as part of all communication transactions.
17. Each Meter shall be capable of capturing and recording a time stamped instantaneous voltage at configurable intervals ranging from one (1) minute to one (1) hour.
18. Each Meter shall be capable of sensing and capturing high/low voltage variations with reference to user definable set points and, upon exceeding the predefined limits, send notifications. Note the requirement above to include industry-standard Power Quality definitions in a setup picklist.
19. Meter shall support an indelible event log sufficient to contain entries for at least sixty (60) days after which oldest entries are over-written first.
20. Meters equipped with an internal service switch shall log all disconnections and connections within its indelible event log.
21. Meter shall communicate to both its event log and the Head-end any service reconnection and disconnection events.
22. Meter shall log to its indelible event log messages (informational and functional) received from the Head-end with Meter date/time and message code.
23. Meter shall detect and store as an event that an electrical parameter (voltage, current, load) has differed from a specified threshold for a configurable period of time.
24. Meter shall be able to discern authorized access to internal tables and information. Meter shall immediately transmit any events that indicate a breach of Meter's data by an unauthorized user or other security threat. The transmission of the data must continue until the AMI Head-end responds with a validation confirming that the data was received.

6.3.14 Tamper/Theft Detection

1. Meter shall detect physical tampering, such as Meter removal, case/cover removal, etc. and generate a tamper event.
2. All tamper related events shall be stored in the Meter's event log. Events shall be stored for at least sixty (60) days.
3. Meter shall be capable of detecting and alarming on an inverted Meter condition.
4. Meter shall be capable of sending a removal tamper event before communications are interrupted.
5. For each tamper event, Meter shall transmit to the Head-end and locally log the following information about the event: timestamp, tamper status (event type), Meter ID. This tamper information should be in a format that supports SIEM security logging services.

6.3.15 Power Quality

1. Meter shall have report by exception capabilities for selected parameters e.g. voltage, demand, etc. for operational purposes.
2. Meter shall be capable of recording both instantaneous and average voltage, current, power factor, kWh, kVArh, and kW values during each interval.

3. Meter shall monitor voltage and current in order to detect power quality variations as defined by CAN/CSA 61000-4-30, IEEE 1159, CBEMA/ITIC and IEC 61000-4-30 standards. These industry standards shall be selectable in a configuration tool pick list at Meter program time.
4. Meter shall allow authorized Company employees to retrieve any recorded device information including logs both locally and remotely (on-demand). Local communication has priority over remote. Such communication shall be supported using Supplier tools connected using the optical port (if so equipped), the mesh network (using a wireless field tool), or from a remote desktop through the corporate network to Meter. All such communication shall conform to corporate security practices as defined elsewhere.
5. Meters with power quality capabilities shall store the power quality data for a period of up to sixty (60) days.
6. Each Meter shall be capable of sensing and capturing high/low voltage variations with reference to Company configurable set points and, upon exceeding the predefined limits, send notifications.
7. Power quality setup shall include an option to use industry standard definitions.

6.3.16 Instrumentation Profiling Data

1. Meter must be capable of transmitting instrumentation data at least every five (5) minutes (configurable for five (5), fifteen (15), thirty (30) and sixty (60) minutes) or on demand.
2. When equipped with instrumentation profiling data, Meters shall be required to capture date, time, and measurement value for minimum, maximum, instantaneous and average values per phase and total for the following:
    a. Voltage
    b. Current
    c. Temperature
    d. Power (kW)
    e. Reactive power (kVAr)
    f. Apparent power (kVA)
    g. Power factor
    h. Harmonics
    i. Average values to be configurable for instantaneous, five (5), fifteen (15), thirty (30), and sixty (60) minutes

6.3.17 Functionality Requirements for Meters

1. All Class 320 Meters shall have a green background nameplate.
2. All Meters shall have a separately configurable alternate display and test display that can display all Meter measured quantities. Additionally, Meters shall be separately configurable to display instantaneous individual phase current, voltage and associated phase angles in normal, alternate, and test modes.

6.3.18 Bellwether Meter Functionality

1. Bellwether Meters shall be equipped to measure, record, and transmit no less than the following parameters:
    a. kWh delivered and received
    b. kVArh delivered
    c. kVAh

d. Voltage
e. Current
f. Temperature

2. Load profile interval data from all bellwether Meters shall be made available to the Head-end no more than twenty (20) seconds after the close of every Meter load profile interval.

6.3.19 Meter Support for Home Area Network (HAN)

1. All Meters shall be certified to operate as an Energy Service Portal (ESP) as detailed in the ZigBee® Alliance Smart Energy Profile (SEP 1.x) specification (ZigBee® Document Numbers 07-5356-19 and revisions).
2. All Meters shall be certified to operate as ESP as detailed in the ZigBee® Alliance Smart Energy Profile (SEP 2.x) specification (ZigBee® Document: Smart Energy Profile 2, 13-0200-00, April 2013 and revisions).
3. All direct connected AMI Meters shall be certified to operate as ESP as detailed in the ZigBee® Alliance Smart Energy Profile (SEP) specification (ZigBee® Document Numbers 075356r14 and 084914r03).
4. ESP shall operate in the 2.400 to 2.4835 GHz ISM band and comply with FCC regulations. ESP shall be capable to operate with an effective radiated power of up to 36 dBm.
5. ESP shall be configured to operate in a Utility Private HAN and shall support all ESP mandatory and optional clusters.
6. Communications to all HAN devices shall first require that those devices join the Utility Private HAN using a secure method that is approved by Company.
7. ESP shall be capable of interacting with a minimum of sixteen (16) Smart Energy Profile certified devices that have joined the Utility Private HAN. AMI system shall support an average of three (3) HAN devices per ESP.
8. AMI system shall enable the interactions between the Head-end and ESP as detailed SEP.
9. AMI system shall provide to ESP, and ESP shall store, tariff information required to allow ESP to populate the fields in the SEP publish price command for implementation of a TOU tariff (with at least one (1) set of seven (7) TOU periods for weekdays, one (1) set of seven (7) TOU periods per Saturday and one (1) set of seven (7) TOU periods per Sunday) and critical peak price notification.
10. Meter shall record as an event when tariff information is updated or changed in the ESP.
11. Home Area Network: All Meters shall be certified to operate IEEE 802.11 (Wi-Fi).
12. Meter shall record as an event any confirmation or status response (arising from a command from the AMI system) that ESP receives from HAN devices, triggered by:
    a. A message confirmation (as detailed in the SEP) from a HAN device.
    b. A load control report event status (as detailed in the SEP) from a HAN device.
    c. A notification that a HAN device has joined or failed to join the Utility Private HAN.

7 AMI Electric Commercial Meter Requirements

7.1 Non Functional Requirements

1. Supplier’s final assembled products shall have wholly integrated Itron Gen 5 NIC devices.
2. Supplier’s products shall perform up to the:
    a. Specifications stated by Company

b. Requirements drafted by Company

7.2 Detailed Security Requirements for Every AMI Electric Commercial Meter Supplied

1. Security requirements shall apply to all AMI Meter types that are deployed on Company AMI network.
2. Encryption of data stored in Meter memory and in the transfer from CPU to memory shall be required.
3. Meter shall lock/disable chip diagnostic and programming ports (JTAG).
4. Provisions for secure local access shall be made available through the network or secure direct connection to Meter (i.e. optical port).
5. Meter (and Field Tool) shall include cryptographic secured authorization/authentication for local Meter data download attempts.
6. NIC shall be integrated with Meter under the cover.
7. Meter shall log all login attempts to its indelible log and support a lockout for a configurable amount of time upon repeated invalid attempts. Supplier shall provide list of other security events that the system is capable of logging. Additionally, Meters must send log alerts to Company for further analysis and response.
8. Meter shall support, at minimum, symmetric key lengths of 128 bits.
9. Supplier shall provide detailed cryptographic key management description explaining how cryptographic material is provisioned, used, stored, and deleted within the system.
10. NIC shall explicitly deny an information flow based on illegal message structure. NIC shall have provisions to detect and thwart a message replay attack e.g. as per ANSI C12.22.
11. Meter shall employ mechanisms that ensure device integrity from external tamper and compromise.
12. Meters shall comply with cyber security programs based on good industry standards based on NIST SP800-53, SP800-82 and NISTIR 7628.
13. Meter shall supply a Meter-to-Head-end, cryptographic solution which assures the confidentiality of Meter's data while in transit.
14. Meter shall supply mechanisms which allow for secure device authentication, registration, and revocation.
15. Meter shall supply cryptographic mechanisms or materials which allows for unique device identification, authentication and communications.
16. Meter shall supply cryptographic mechanisms or materials which allows for group access.
17. Meter shall supply mechanisms which audit, store and transfer to SIEM of all security related events including all access and modifications events within the system.
18. Meter shall supply a security audit store which includes the date and time of the event, type of event, user identity, and the outcome (success or failure) of the event and transfer this event to Company's SIEM.

7.3 Meter Functional and Performance Related Requirements

7.3.1 Compliance to Company Specifications

1. All Meters shall:

a. Meet, or exceed, Supplier's technical and functional specifications over the twenty (20) year lifetime of the product.
b. Meet, or exceed, the Electric Meter Requirements herein.
c. Be inclusive of the third party NIC device.

7.3.2 Interoperability and Standards

1. Meters shall be built to ANSI C12 standards.
2. Meters shall have an interface capable of supporting multiple communication modules furnished by multiple potential Suppliers. Communications modules will reside under Meter cover and collectively support the functional and non-functional requirements as specified in this Request for Proposal.
3. NIC furnished by potential Suppliers shall have an interface capability for the life of Meter.
4. There shall be transparent IP routing to Meters. Meters and control devices shall be configurable to support either or both of IPv-4 and IPv-6 communication.
5. All electric Meters shall have a 0.5% or better accuracy class.

Please refer to Appendix 2 at the end of this document for Enterprise Technology Standards.

7.3.3 Meter Feature Requirements

1. Meters shall be equipped with temperature sensors capable of measuring and logging Meter temperature for detection of hot sockets.
2. Meter shall be capable of reporting internal temperature as an interval channel or a temperature alarm as specified below:
   a. Meter shall be capable of reporting internal temperature for purposes of hot socket detection. When equipped with an internal service switch, Meters shall be capable of remote disconnect initiated by back office function.
   b. Meter shall be capable of generating an alarm when a configured internal temperature is exceeded. When equipped with a service disconnect switch, Meters shall be capable of remote disconnect initiated by back office function.
3. Meters shall be equipped with tilt/motion sensors.
4. Tilt/motion shall be captured/processed at power down by motion sensors to differentiate removal from normal outage.
5. Meter internal timekeeping clocks shall be governed by a disciplined clock analogous to that used by the Network Time Protocol (NTP) in which the clock speed, rather than the clock setting, is adjusted to effect time error corrections. In this case, Meter clock should be disciplined against the clock which governs the anticipated mesh network. With a disciplined clock there will never be discontinuities in the time record of, for example, load profile records which would produce short and long intervals except in the possible case of power-up operations when the clock is initially set. Reference the RFC 1129 NTP algorithms are described in a 1989 paper at URL: https://www.ietf.org/rfc/rfc1129.pdf. The case of a GPS disciplined clock is described in a Wiki article at URL: https://en.wikipedia.org/wiki/GPS_disciplined_oscillator.
6. Transformer rated Meters shall optionally allow Company to include potential and current ratios in the transmitted Metered data.
7. Meter shall be able to self-register on the AMI network and communicate to the field network setup tool whether or not all aspects of the Meter and its communication with the AMI system are operating properly.

8. Load profile data shall be recorded and date/time stamped at the end of each interval. The date and time stamping of load profile data shall be consistent with ANSI C12.19
9. Meter shall be configurable to support delivered, received, net and absolute power at the Meter.
10. Meter shall support a configurable flag on detected reverse power flow. This flag would send an alarm when reverse power flow is detected. Parameters would include recognizing reverse flow at a configurable level (watts to kilowatts) over a configurable interval (five (5) seconds to one (1) hour) to prevent false triggering.
11. Meter shall support a network time synchronization of one (1) second or better and be able to time stamp its voltage peak to an accuracy of one (1) second. If an optional Phase Detection feature is deployed which requires greater time accuracy and resolution, Meter shall support such increased time resolution.
12. Load profile interval shall be configurable from one (1) minute to twenty four (24) hours (one (1) minute, two (2) minutes, five (5) minutes, ten (10) minutes, fifteen (15) minutes, thirty (30) minutes, sixty (60) minutes, one (1) day).
13. Both Meters and communication devices must be capable of hard resets to factory default conditions by local means without shipping back to Supplier.
14. To facilitate Meter processing and installation, Meters and NICs shall be uniquely identifiable by both bar coding and electronic communication. Meter label shall conform to Company standard template which will be provided prior to manufacture date and confirmed during First Article Testing.
15. Both Meter and communication infrastructure shall support remote desktop access to Meter using Supplier's native configuration software (e.g., Metercat, PCPro, etc.) over an IPv4 and/or IPv6 connection. This remote access shall be possible in equivalent terms through Meter's optical port if so equipped, through the field area mesh network, and through the enterprise network from, for example, a Meter technician's desktop.
16. Each Meter shall have the capability to Backup and Restore.
17. Meters shall support independent demand register times so that meters can simultenously support multiple demand intervals e.g. 5, 15, 30 and 60 minutes.

7.3.4 Upgradeability and Configurability

1. Each of Meter subsystems (e.g. metrology, register, Meter configuration [Program], HAN (If equipped) and Network Interface [NIC]) shall be upgradeable by secure remote download.
2. Each of Meter subsystems shall have sufficient memory to support, at minimum, an anticipated 2x increase in memory requirements due to future enhancements and/or bug fixes.
3. Each of Meter subsystems shall have sufficient memory to maintain operating, previous and in-transit images of their respective firmware and shall support rollback to the previous successful image in the event of an error in either transmission or configuration that might require such rollback.
4. Residential Meters, if equipped with a service switch, shall have the ability to limit load/service. The load limit shall be configurable such that multiple configurable steps (e.g. ninety percent (90%) of rated capacity, seventy five percent (75%) of rated capacity, etc.) can be configured in the AMI Meter.
5. If bi-directional energy measurement functionality is required to be activated in Meter, Meter shall be able to be re-programmed remotely over the air. This reprogramming event will be logged in Meter and sent back to the Head-end immediately.

6. Data sent from Meters shall be configurable as to whether interval data, register data, event data or all shall be sent during routine or on-demand Meter read requests.
7. Meter shall permit TOU, CPP, and PTR time period to be remotely configurable.
8. Meter shall permit its firmware and programs to be remotely downloadable without loss of register data.
9. Meter shall report failures, e.g. communication failure after reboot, program lock-up, etc., following a software/firmware upgrade within fifteen (15) minutes after start-up of new program. Reportable failures shall include billing information loss or loss of electric service. Meter failures to report shall be configurable in Meter program.
10. Register Meter functions shall be programmable both remotely and locally.
11. Handling of received energy shall be configurable in Meter, e.g. sum of delivered and received energy, ignored, net, etc.
12. Meter feature set shall include an indelible logging facility that records all administrative actions, for example reconfiguration, performed on Meter and report it to the AMI Head-end. Indelible log shall survive Meter reprogramming and firmware upgrades.

7.3.5 Availability

1. Meter shall continue to record all required data during a communication failure.

7.3.6 Connect, Disconnect, or Limit Service

1. Class 320 (Forms 2S and 12S) shall be able to remotely connect/disconnect/limit electric service to customer premises.
2. Service switch shall be rated for at-least 10,000 service disconnect/reconnect operations.
3. Meter shall be able to limit demand served to the customer by a remote utility on-demand request or through utility pre-configured rules (e.g. 90% of rated capacity, 75% of rated capacity, etc).
4. Meter's disconnect switch shall be capable of inhibiting the close operation when there is voltage on the load side to prevent equipment damage or personal injury.
5. Remote disconnect shall be integrated with Meter rather than a collared solution for Meter types that have been identified as requiring a disconnect switch.
6. Meter shall permit remote changes to the threshold for load limiting from MDM or Head-end. Thresholds shall be configurable.
7. Internal service switch shall have a rating consistent with Meter class rating at 60% lagging power factor.
8. Internal service switch shall close a configurable number of times automatically after a configurable delay if internal service switch trips open because the demand/energy limit is exceeded.
9. Meter shall acknowledge load limit command successful to Head-end.
10. Meter shall acknowledge and communicate open/close status of the internal service switch after operating command is issued and shall be confirmed by Head-end.
11. Internal service switch shall be operable through the optical port and/or through the Field Tool used for Meter installation and maintenance.
12. Meter disconnect event (remote or local) shall not generate a last gasp message.
13. Meter shall record a disconnect event if the switch operates without a command.

7.3.7 Visible Access to Data

1. Meters equipped with an internal service switch shall provide for an external indication of the switch status discernable to a customer or Company employee on site.
2. Meter display shall provide date and time as specified by the utility. The display shall also display and label measured quantities in engineering units.
3. Displayed data shall match stored and transmitted data.
4. Meters shall be capable of displaying registers of all possible Metered data. Displayed data must show associated metrics/unit of measure.
5. Meter display shall include status of FAN communication link.
6. If equipped with home area network (HAN) or internet of Things (IoT) interface, Meter shall display status of HAN/IoT communication.
7. A visual disk emulator shall be provided on all Meters.
8. Meter shall be able to operate in alternate and test modes and display separately configurable alternate and test mode display sets.
9. Meter shall be placed into alternate and test modes locally. Test mode to have configurable time out period (reverting to normal mode) and ability to be set to normal mode remotely.
10. Normal and alternate displays to include error and warning conditions.

7.3.8 Demand Response

1. Meter will not inhibit Company practice that all control and reconfiguration commands sent through the field area network must be confirmed by field devices to the back office within fifteen (15) seconds.

7.3.9 Distributed Generation

1. Meter shall collect delivered, received, and net cumulative values, as well as interval data as signed (positive or negative) values. Delivered cumulative shall be equal to the sum of delivered intervals, received cumulative shall be equal to the sum of received intervals. Both time duration and energy threshold shall be configurable in seconds.
2. Meter display shall be configurable to display any or all of the measured quantities identified in item 1 above.

7.3.10 Installation and Maintenance

1. NIC in Meter shall have Unique Identification for: LAN, FAN.
2. Meter shall have an indelible unique serial number over the life of the AMI system.
3. If equipped with HAN/IoT, Meter shall have a unique ID for HAN/IoT communication.
4. Upon installation, Meter shall optionally recognize, as configured by Company, the service type and issue alarm messages for unrecognized services (or abnormal service conditions). Meter shall have functionality that enables it to individually disable service level alarms.
5. Meter shall be able to identify itself to field network setup tool and provide access to its data and configuration settings at installation time, and later in support of ongoing operations and maintenance activities subject to security authorization.
6. Meter performs self-check and reports results to installer field tool, local display, and to the AMI network. Self-checks to include integrity of the HAN/IoT communications card (if present) and AMI network communication card and ability to communicate with local collector (AMI communication network architecture dependent).

7. Meter shall be capable of communicating with Supplier-supplied Field Tool over the NAN network via the Meter's NIC.
8. Field Tool shall be capable of operating internal service switch and resetting demand.
9. Field tool shall be capable of communicating to Meter using wireless mesh network with at least the same functionality as is offered using shop or desktop tools.

7.3.11 Meter Measurement Capabilities

1. Meter shall provide time-stamped peak demand and energy for all configured time-of-use periods.
2. On the occurrence of an on-demand interval data read, Meter shall be capable of sending time stamped any selected or all stored data and other associated register and diagnostic information.
3. Based on Company requirements, Meter shall complete a self-read and store the value for each channel register of data.
4. On the occurrence of a scheduled read, Meter shall be capable of sending time stamped any selected or all stored data and other associated register and diagnostic information.
5. Voltage resolution reported to Head-end shall be 0.1V or better.
6. Power Factor calculations shall include at least the following: average, max, min, coincident, etc.
7. Power Factor calculations shall have both options for using either the total power factor (real power/apparent power) or the displacement power factor (cos(θ)) methods.
8. Supplier shall provide detailed description of each of the options available for power factor calculation.
9. Meter shall accommodate a minimum of sixty (60) days of load profile data with five (5) minute intervals for at least four (4) channels of data.
10. Meters shall support TOU and critical peak pricing capabilities including: (a) four (4) TOU rates (b) Critical peak pricing rate (c) Ability to switch between Time Zones (d) Ability to switch between Standard Time and Daylight Saving Time (e) Support for four (4) Seasons (f) Support advance calendar for at least twenty (20) years including Holidays.
11. Commercial Meters shall be configurable to measure both integrated and instantaneous values (linear average over one (1) second) for the following:
    a. kW
    b. kVAr
    c. Voltage
    d. Current
    e. kVA
12. Commercial type Meters shall be configurable to provide at least the following register and interval data:
    a. kVArh delivered and received.
    b. kWh delivered and received.
    c. Internal Meter temperature and temperature alarm.
    d. Voltage magnitude and angle.
    e. Current magnitude and angle.
    f. kVAh delivered and received.

13. Commercial meters shall have capability for selecting either vectorial or arithmetic methods for calculating KVA delivered and received.

7.3.12 Outage Management

1. Meter shall be capable of sending a message if load side voltage is detected on a disconnected Meter.
2. Meter shall maintain sufficient function for a sufficient amount of time to differentiate between an interruption and a power quality (PQ) event.
3. Meter shall alarm if voltage less than a configurable threshold is detected for a configurable period of time.
4. Meter shall alarm if voltage greater than a configurable threshold is detected for a configurable period of time.
5. Meter shall detect and send a last gasp/tamper alarm to the Head-end. Detection shall be possible after Meter is removed and before it stops communicating.
6. Meter shall be able to send a last gasp message over the communications network during an interruption or removal.
7. At the system level, Meters shall remain operational after an interruption for a period of time that is sufficient to achieve:
   a. 100% reporting on single meter outage.
   b. 90% of meters reporting on outages of up to 1000 Meters.
   c. 80% of meters reporting on outages of 11 to 100 Meters.
   d. 60% of meters reporting on outages of 101 to 1,000 Meters.
   e. 50% of meters reporting on outages of up to 10,000 Meters.
   f. 30% of meters reporting on outages of 1,001 to 10,000 Meters.
8. Measurements of momentary interruptions, momentary interruption events, and sustained interruptions shall be consistent with IEEE Std 1366-2012. In the case where IEE 1366 standard changes, the new definition shall supersede the old.
9. A single momentary interruption event includes all momentary interruptions experienced by Meter within a configurable period (e.g. five (5) minutes, etc.). Service must be restored within a configurable time period (e.g. five (5) minutes) to be classified as a single momentary event.
10. An interruption of less than a configurable time period (e.g. five (5) minutes) shall be considered a momentary interruption and shall be logged by Meter as a momentary interruption.
11. An interruption of more than a configurable time period (e.g. five (5) minutes) shall be considered a sustained interruption and shall be logged by Meter as a sustained interruption. The sustained interruption includes all the switching events from the initial interruption to full restoration of the sustained interruption event.
12. Data recorded by AMI Meters will be used to calculate Momentary Average Interruption Frequency Index (MAIFI) and Momentary Average Interruption Frequency Event (MAIFIE). MAIFI and MAIFIE include all momentary interruptions that are not part of a sustained interruption.
13. A single interruption shall trigger Meter logging.
14. Momentary interruptions shall be reported up to the Head-end with the next scheduled Meter read.

15. The above notwithstanding, power quality event selection shall be possible based on a pick-list of industry accepted power quality events in Meter setup tool in addition to ad-hoc definitions entered at Meter configuration definition.

7.3.13 Reliability

1. Supplier shall provide accelerated life testing results for all the system components that substantiate the system's life and that identify top failure causes.
2. Meter must survive and function properly without losing data or programs through repetitive short-term power outage cycles as might be experienced by recloser operations.
3. Meter time clock shall be configurable through the network and shall be accurate with a drift rate of no worse than one (1) minute per year. Meter clock shall be governed by a disciplined clock controlled by the system time using techniques similar to the Internet Network Time Protocol (NTP). Maximum allowable deviation from absolute time is no greater than one (1) second. Reference discussion Disciplined Clock above.
4. Meter shall be provisioned with an indelible log to receive event entries.
5. Type of events logged by Meter shall be configurable. Event messages for transmission and priority shall be determined by Company.
6. Meter shall send acknowledgement of a successfully completed or failed electric service connect/disconnect/limit event to the Head-end with latency not to exceed twenty (20) seconds.
7. Meter shall log the date and time stamped establishment of load limit set points.
8. When Meter's rated and configured load limits are exceeded, support for solicited and unsolicited reporting shall be available.
9. Meter shall log all local (and remote) Meter access attempts (configuration, data download, time adjustments, etc.), whether successful or not, and the requester ID. The system shall support solicited and unsolicited reporting.
10. Meter shall be able to detect loss of load (greater than a configurable period of time) on the customer side of the Meter that is not related to a remote disconnect, log the event, and send an event message to Head-end. When load is restored, Meter shall log the event.
11. Meter reinstallation events shall be sent to Head-end immediately upon reinstallation along with any unsent tamper events.
12. An event generated when Meter is reinstalled is different from an event generated if Meter is initially installed (provisioned) or re-energized (e.g. after an outage). This is to avoid transmission of useless and confusing information to the enterprise systems because of non-tamper related events.
13. Meter's internal clock shall be synchronized in such a manner that Meter data that includes register and interval data shall not be affected and shall log the event. This requires the use of a disciplined clock governing the Meter as discussed above.
14. Meter shall be able to detect and log communications link failures upon failed communications initiated from Meter.
15. Meter shall be able to send an alarm/event to the Head-end (in the format in which Head-end can receive) when a configurable number of consecutive communications link failures are detected (e.g. three (3) consecutive link failures).
16. Meter NIC shall be able to periodically record the communication signal strength and report it back to the Head-end as part of all communication transactions.

17. Each Meter shall be capable of capturing and recording a time stamped instantaneous voltage at configurable intervals ranging from one (1) minute to one (1) hour.
18. Each Meter shall be capable of sensing and capturing high/low voltage variations with reference to user definable set points and, upon exceeding the predefined limits, send notifications. Note the requirement above to include industry-standard Power Quality definitions in a setup picklist.
19. Meter shall support an indelible event log sufficient to contain entries for at least sixty (60) days after which oldest entries are over-written first.
20. Meters equipped with an internal service switch shall log all disconnections and connections within its indelible event log.
21. Meter shall communicate to both its event log and the Head-end any service reconnection and disconnection events.
22. Meter shall log to its indelible event log messages (informational and functional) received from the Head-end with Meter date/time and message code.
23. Meter shall detect and store as an event that an electrical parameter (voltage, current, load) has differed from a specified threshold for a configurable period of time.
24. Meter shall immediately transmit any events that indicate a security threat. The transmission of the data must continue until the AMI Head-end responds with a validation confirming that the data was received.

7.3.14 Tamper/Theft Detection

1. Meter shall detect physical tampering, such as Meter removal, case/cover removal, etc. and generate a tamper event.
2. All tamper related events shall be stored in Meter's event log. Events shall be stored for at least sixty (60) days.
3. Meter shall be capable of detecting and alarming on an inverted Meter condition.
4. Meter shall be capable of sending a removal tamper event before communications are interrupted.
5. For each tamper event, Meter shall transmit to the Head-end and locally log the following information about the event: timestamp, tamper status (event type), Meter ID. This tamper information should be in a format that supports SIEM security logging services.

7.3.15 Power Quality

1. Meter shall have report by exception capabilities for selected parameters e.g. voltage, demand, etc., for operational purposes.
2. Meter shall be capable of recording both instantaneous and average voltage, current, power factor, kWh, kVArh, and kW values during each interval.
3. Meter shall monitor voltage and current in order to detect power quality variations as defined by CAN/CSA 61000-4-30, IEEE 1159, CBEMA/ITIC and IEC 61000-4-30 standards. These industry standards shall be selectable in a configuration tool pick list at Meter program time.
4. Meter shall allow authorized Company employees to retrieve any recorded device information including logs both locally and remotely (on-demand). Local communication has priority over remote. Such communication shall be supported using Supplier tools connected using the optical port (if so equipped), the mesh network (using a wireless field tool), or from a remote desktop through the corporate network to the Meter. All such communication shall conform to corporate security practices as defined elsewhere.

5. Meters with power quality capabilities shall store the power quality data for a period of up to sixty (60) days.
6. Each Meter shall be capable of sensing and capturing high/low voltage variations with reference to Company configurable set points and, upon exceeding the predefined limits, send notifications.
7. Power quality setup shall include an option to use industry standard definitions.

7.3.16 Instrumentation Profiling Data

1. Meter must be capable of transmitting instrumentation data at least every five (5) minutes (configurable for five (5), fifteen (15), thirty (30) and sixty (60) minutes) or on demand.
2. When equipped with instrumentation profiling data, Meters shall be required to capture date, time, and measurement value for minimum, maximum, instantaneous, and average values per phase and total for the following:
   a. Voltage
   b. Current
   c. Temperature
   d. Power (kW)
   e. Reactive power (kVAr)
   f. Apparent power (kVA)
   g. Power factor
   h. Harmonics
   i. Average values to be configurable for instantaneous, five (5), fifteen (15), thirty (30), and sixty (60) minutes

7.3.17 Functionality Requirements for Meters

1. All Class 320 Meters shall have a green background nameplate.
2. All Meters shall have a separately configurable alternate display and test display that can display all Meter measured quantities. Additionally, Meters shall be separately configurable to display instantaneous individual phase current, voltage, and associated phase angles in normal, alternate, and test modes.

7.3.18 Meter Support for Bellwether Services

1. Bellwether Meters shall be equipped to measure, record, and transmit no less than the following parameters:
   a. kWh (delivered and received)
   b. KVArh (delivered and received)
   c. KVAh
   d. Voltage
   e. Current
   f. Temperature

2. Load profile interval data from all bellwether Meters shall be made available to the Head-end no more than twenty (20) seconds after the close of every Meter load profile interval.

7.3.19 Meter Support for Home Area Network (HAN)

1. All Meters shall operate as an Energy Service Portal (ESP) as detailed in the ZigBee® Alliance Smart Energy Profile (SEP 1.x) Specification (ZigBee® Document Numbers 07-5356-19 and revisions).
2. All Meters shall operate as ESP as detailed in the ZigBee® Alliance Smart Energy Profile (SEP 2.x) Specification (ZigBee® Document: Smart Energy Profile 2, 13-0200-00, April 2013 and revisions).
3. All direct connected AMI Meters shall be certified to operate as ESP as detailed in the ZigBee® Alliance Smart Energy Profile (SEP) Specification (ZigBee® Document Numbers 075356r14 and 084914r03).
4. ESP shall operate in the 2.400 to 2.4835 GHz ISM band and comply with FCC regulations. ESP shall be capable to operate with an effective radiated power of up to thirty-six (36) dBm.
5. ESP shall be configured to operate in a Utility Private HAN and shall support all ESP mandatory and optional clusters.
6. Communications to all HAN devices shall first require that those devices join the Utility Private HAN using a secure method that is approved by Company.
7. ESP shall be capable of interacting with a minimum of sixteen (16) Smart Energy Profile certified devices that have joined the Utility Private HAN. The AMI system shall support an average of three (3) HAN devices per ESP.
8. AMI system shall enable the interactions between the Head-end and the ESP as detailed SEP.
9. AMI system shall provide to ESP, and ESP shall store, tariff information required to allow ESP to populate the fields in the SEP publish price command for implementation of a TOU tariff (with at least one (1) set of seven (7) TOU periods for weekdays, one (1) set of seven (7) TOU periods per Saturday and one (1) set of seven (7) TOU periods per Sunday) and critical peak price notification.
10. Meter shall record as an event when tariff information is updated or changed in the ESP.
11. Home Area Network: All Meters shall be certified to operate IEEE 802.11 (Wi-Fi).
12. Meter shall record as an event any confirmation or status response (arising from a command from the AMI system) that the ESP receives from HAN devices, triggered by:
    a. A message confirmation (as detailed in the SEP) from a HAN device.
    b. A load control report event status (as detailed in the SEP) from a HAN device.
    c. A notification that a HAN device has joined or failed to join the Utility Private HAN.

8 General Requirements for Electric Installation Services

8.1 Scope of Supply

1. Supplier shall fulfill the requirement to install the inventory of electric Meters in accordance with the Project Schedule.
2. In the event Supplier hires sub-contractors to perform work, the same requirements, processes and expectations shall hold true for sub-contractors as Supplier's. Supplier will be held responsible for all work, damages or any other issues caused by sub-contractors. Company reserves its right to review Supplier's sub-contractors' past safety and quality performance as well as their relevant experience for the tasks being sub-contracted.
3. Throughout the electric Meter deployment period, Supplier will adhere to completing device exchanges according to the provided reading/billing schedule. As installed Meters move into bill window dates, Supplier will refrain from exchanging Meters in any reading/billing cycles that are in the bill window.

4. Company expects field installations shall be completed during normal business hours Monday-Friday between the hours of 8:00am and 5:00pm local time. Company shall review, and potentially approve, any Supplier proposed exceptions.
5. Working on Saturday's may be acceptable but field installations shall not commence before 9:00am local time, unless a scheduled appointment was previously setup by customer request. Supplier shall be required to notify and receive approval from Company when field installations will be done on Saturdays. Supplier will not be additionally compensated for Saturday installations, unless the work is specifically requested in writing by Company.
6. Installation requirements include, but are not limited to:
    a. Supplier shall install electric Meters in accordance with guidelines regarding installation procedures provided herein.
    b. Supplier shall safely install/exchange electric Meters of all types in accordance with AMI Project Schedule (schedule to be refined and fully developed after contract award) utilizing qualified personnel.
    c. Supplier shall complete electric Meter exchange orders and ensure those orders are successfully transferred to Company provided work order management tool on a daily basis.
    d. Supplier shall provide staging/cross-docking facilities for incoming and disposal of electric Meters.
    e. Company shall supply six (6) weeks of inventory of new electric Meters including all electric Meter forms and classes. Non-AMI electric meters will be held for six (6) weeks. After this time, meters will be processed for retirement and disposal.
    f. Supplier shall provide inventory control of new and used electric Meters.
    g. Supplier shall provide asset management of electric Meters.
    h. Supplier shall provide disposal of replaced electric meters in accordance with Section 8.13 and Section 8.14.
    i. Supplier shall recycle sufficient number of AMR electric meters removed from the field to support existing non-AMI meter business requirements in areas that have not been deployed with AMI. Company will coordinate with Supplier on desired inventory levels.
    j. Supplier shall capture GPS Latitude and Longitude of Meter locations as part of the Meter exchange process. Coordinates must not be truncated to fewer than five (5) places after the decimal point; for example 37.46668 rather than 37.466.
7. Anticipated installation rate is outlined in Section 1.3.7 but subject to agreement between Supplier and Company in writing. Refer to Appendix 3 (PSCo Electric Meter Deployment) for anticipated rollout by quarter and block..

8.2 Obligations Concerning Meter Deployments

Supplier shall:

1. Perform Meter exchanges as outlined herein.
2. Use Company electronic work order system or functional equivalent that collects barcode data and GPS coordinates for each location where Meters and mesh network transition equipment is installed. Supplier can offer alternate proposal for using Supplier's work order management solution. Additional discussions will be required with Company, if Supplier offers an alternate proposal.
3. Ensure that cyber security key material is handled according to Company's security requirements during all lifecycles of Meter (i.e., manufacturing, installation, exchange, removal and destruction).
4. Ensure the confidentiality of Meter and FAN network configuration specifications.
5. Be responsible for ensuring company safety procedures and policies are complied.

8.3 Items Supplied by Company

1. Company will provide Supplier with necessary work asset management/work completion business software application tool during deployment for all field personnel performing electric Meter exchanges. Such tools will be loaded with Company's software allowing for real time order completion. Some work requirements may not apply should Supplier propose, and Company accept, an alternate work tool.
2. Company will provide Supplier with bar code scanners for each of the field asset tools issued during deployment. Requirements will not apply should Supplier propose an alternate work tool.
3. Company provided work asset tool will have access to software Application used for inventory tracking and instruct Supplier on its operation. Inventory tracking requirements shall still apply should Supplier propose an alternate work tool.
4. Company will provide Supplier keys for all Company owned locks, lock boxes and barrel locks for accessing meters and/or locked meter rooms.

8.4 Required Tools and Instrumentation

1. Supplier shall provide all tools necessary for the safe installation or exchange of electric Meters.
2. Supplier shall be responsible for acquisition and installation of truck mounts for work order management tools and any associated costs for installation of pedestal materials for all field vehicles. Company will provide Supplier with work order management tool cradles. Pedestals are a customized item depending on type of vehicle and will need to be secured to the vehicle.
3. If Supplier proposes, and Company accepts, Supplier's own work order management tool, Supplier shall provide all tools and work order management system including handhelds/tablets equipped with cameras required to perform and validate proper electric Meter exchanges.
4. For Company to accept a Supplier-proposed Meter installation work management software application tool, Supplier shall provide Company with full description of tools, apps, and procedures.

8.5 Required Customer Notification Process

1. Company will inform customers of the expected timeframe and procedures for the electric Meter exchange prior to carrying out the exchange through customer mailings or other Forms of communications.
2. Company will notify law enforcement and city officials of the working areas.
3. Supplier shall attempt to contact all customers upon arrival before accessing electric meter to perform exchanges.
4. Supplier shall leave a Company-supplied door hangar at the customer's permises after the electric Meter exchange. Door hanger will include information that the electric Meter was exchanged, reason for the exchange, and information regarding Advanced Metering Infrastructure (AMI). Company will also supply information to Supplier for its employees training program detailing customer communication regarding the electric Meter exchange and benefits of Company's AMI program.
5. If unable to contact customer on arrival, Supplier shall safely attempt to gain access and exchange electric Meter. A customer oriented notification of the completed or pending action shall be left at the customer premise in the form of a door hanger supplied by Company upon completion of electric Meter exchanges.
6. If unable to exchange the Meter due to access issues, Supplier shall follow procedure in Section 8.6.

7. Supplier will coordinate with Company to produce list of customers (daily, weekly, etc.) that are going to be exchanged so that Company can add PTJ's (work orders) to Customer Information System.
8. If Supplier is not able to contact customers that have 3-phase self-contained electric meters, Supplier shall follow procedure in Section 8.6.

8.6 Return to Utility Process / No Access Expectations

1. Supplier shall attempt to make multiple attempts before returning order to Company consisting of:
   a. Two (2) Field attempts.
   b. Two (2) Phone/message attempts to set appointments.
   c. One (1) No access letter sent to the Customer.
2. If Supplier cannot exchange electric Meter after multiple attempts, using the processes outlined above, Supplier shall refer electric Meter exchange to Company for completion. Company will assess no access expectations through a close evaluation of Supplier percentage of RTU's
3. If Supplier cannot exchange electric Meter after following the steps defined above, the work order will be returned to Company and Supplier will bill Company for unsuccessful attempts at the applicable unit rate. An unsuccessful attempt shall be considered to be a single field attempt and not an attempt from the back office.
4. Items 1 and 2 above shall flow through Supplier provided tools or Company work order system.

8.7 Immediate Return to Utility (RTU)

1. Supplier will mark accounts as immediate RTU for scenarios such as suspected tampering, customer refusal, and hazardous conditions. Supplier to outline conditions that qualify for suspected tampering.
2. Such conditions will be billed to Company at the applicable rate.
3. All instances of RTU's shall be documented and tracked.

8.8 Required Procedure for Handling Equipment Damage

1. In the event an unexpected customer outage condition should occur while attempting to complete a Meter exchange, Supplier's field technician shall:
   a. Notify customer (if home) about the unexpected outage.
   b. Report outage to Supplier Supervisor or office personnel, and depending upon the nature of the problem either initiate an order for repair or request a proper order be generated by Company for resolution.
2. If unsafe condition(s) exist, Supplier shall remain on site until relieved by another duly appointed and qualified representative of Supplier's company or until Company representative arrives on site.
3. When Supplier personnel are required to standby onsite, standby time will be billed at the hourly rate listed in the fee schedule if the outage is determined to not be the fault of Supplier's personnel.

8.9 Required Procedures for Property Damage (non-outage related)

1. If damage is caused by Supplier as a result of an improper or accidental action during the electric Meter exchange process, Supplier is responsible for all necessary repairs and associated costs including any Supplier associated Supplier costs above.
2. If damage is unavoidable (due to pre-existing stressed wires or broken block, etc.), Company shall be responsible for needed repairs and all associated costs and will resolve with Customer as appropriate.

8.10 Site Clean-up

1. Any unused, old, or discarded electric meter related materials (demand seals, meter seals, used disconnect boots, index screws, etc.) shall be picked up by Supplier and properly disposed.
2. Disposal shall follow processes outlined in Section 8.13 and Section 8.14.

8.11 Cross Docking Inventory Management

1. Equipment to be provided by Supplier shall include, but is not limited to, tools, work order management tools if provided by Supplier, warehouse equipment (such as fork lift, pallet jacks), computers and associated connections, etc. Any computers requiring Company software (such as MDMS, CRS and Advantex) will be provided by Company.
2. To avoid any potential slowdown for lack of electric Meter inventory, a four (4) week supply of Meters shall be on hand at all times. Below is the average expected weekly peak installation quantities:
   a. PSCo (CO)
      i. Electric Meters – 10,000
   b. NSPM (MN)
      i. Electric Meters – 10,000
   c. NSPM (ND)
      i. Electric Meters – 13,000
   d. NSPM (SD)
      i. Electric – 1,100
   e. NSPW (WI and MI)
      i. Electric Meters – 2,100
   f. SPS (TX and NM)
      i. Electric –3,100
3. Supplier shall coordinate with Company on recycling electric meters that support on-going Meter installation and replacement work in areas that are designated for future AMI deployment.
4. Supplier must participate in regularly scheduled electric Meter inventory planning sessions with Company.
5. Supplier shall secure and equip cross docking facilities for receiving, storing, and dispatching of new electric Meters, as well as storage of returned meters, and preparing them for disposal. Locations of cross docks will vary depending on geographic deployment.

8.12 Inventory Tracking/Reporting Requirements

1. All new electric Meters shall be electronically transferred to appropriate Supplier storerooms at cross docking facilities once they have passed bar-X and network communication testing by Company and have been purchased into Company's Monitor Device Management System (MDMS).
2. Unless otherwise agreed in writing, all electric Meters shall be shipped directly to Supplier's facility. Sample electric Meters will be drawn for acceptance testing to be performed at Company's Meter Shop, or off-site location designated for deployment.
3. Company personnel will initiate transfer process of new electric Meter shipments to a designated Supplier storeroom after each electric Meter shipment has been receipted into MDMS and acceptance testing has been completed.
4. In order to complete transfer process to Supplier's storeroom, Supplier shall verify electric Meters included in pending transfer are correct. Once verified, electric Meters will be receipted in MDMS to complete transfer process to Supplier's storeroom. New electric Meter shipments will be quarantined until the transfer process is fully completed. Company will provide necessary training and access to MDMS to Supplier's office personnel.

5. On a daily basis, individual electric Meters shall be electronically scanned and transferred/assigned to each field technician for daily Meter exchanges in an effort to help reduce the risk of lost electric Meters. Scanners will be provided by Company if Supplier opts to use Company Work Order system.
6. Company will provide necessary training for individual assignment of electric Meters.
7. Individual electric Meter inventory shall be conducted on a daily basis by all field technicians using company supplied inventory software that will be available on Company provided work order management tool. Company will provide training for required inventory procedure. If Supplier proposes a different work order tool, Supplier shall outline how Supplier tool will reconcile inventory with Company systems.
8. Supplier will conduct a complete inventory (at least once a year) that may coincide with Company's own electric Meter inventory or when deemed necessary. An electronic file of all electric Meters both new and used electric Meters not yet retired will be provided by Supplier. Additional information will be given to Supplier prior to scheduled inventory date.
9. At the end of each day, Supplier field personnel shall return a number of old electric meters that match the number of exchange orders completed during the day.
10. At the end of each day, Supplier field personnel shall return electric Meters that are equal to electric Meters taken out minus electric Meters installed.

8.13 Disposal of Equipment Requirement

1. Supplier shall take pictures of each electric Meter clearly showing the electric Meter's ID and Meter index before exchanges. At a minimum, expect to have pictures of total consumption.
2. Supplier shall be responsible for the disposal of all hazardous materials in a safe and environmentally appropriate manner. Supplier warrants that all regulatory and legal requirements are adhered to on the disposal process.
3. Before and after pictures showing Meter service and/or any pre-existing conditions worth noting may also be required to assist in any potential claims or disputes from customers. All pictures will be stored by Supplier and readily available to Company.
4. Supplier shall manage, transport, and recycle or dispose of waste and hazardous materials in accordance with applicable law and Company's Environmental Directives for Contractors.
5. Supplier and any subcontractors that are responsible for recycling of retired meters and modules and recycling or disposal of any associated waste and hazardous materials must be approved pursuant to Company's Procedure ENV 8.811 Waste Vendor Approval and Maintenance Procedure.
6. Supplier shall provide advance written notice to Company disclosing the identity of facilities to be utilized for waste and hazardous material processing, recycling, or disposal. Company shall have two (2) weeks to determine whether proposed facilities shall be rejected.
7. Supplier shall provide advance notice to Company identifying list of transporters that may be used to transport wastes and hazardous material for processing, recycling, or disposal. Company shall have one (1) week to determine whether proposed transporter shall be rejected.
8. Supplier shall provide Company with an annual inventory of hazardous materials disposed of or recycled. The annual reports must identify the total pounds of each waste type (i.e., mercury contaminated waste, batteries and circuit boards) recycled or disposed of in the calendar year

8.14 Meter Disposal/Retirement Process

1. Supplier shall be responsible for providing information to Company for recycling of retired meters and modules in Company's meter inventory management system.
2. Meter sorting will be required for meters that will be retired, and re-usable meters, based on Company-defined lots and Customer needs.

3. Supplier will separate and segregate all environmentally hazardous materials and recycle or dispose of in accordance with Section 8.13 prior to recycling the retired meters or modules.
4. The remaining meter or module components will be recycled by Supplier.
5. Prior to recycling, Supplier shall be required to provide a nightly file containing meters and modules that have been removed from the field and are being retired. Supplier and Company will mutually agree upon the required file format and layout for this process. The file shall contain pertinent information to revoke the retired meter's participation in Company's FAN (i.e., Certificate revocation).
6. Supplier will bear the responsibility for the quantity of meters and modules recycled as compared to the required nightly file containing meters and modules that have been removed from the field for retirement and recycling.
7. Supplier shall provide a list of all Third Parties that are utilized for recycling of meters and modules.
8. Supplier shall provide cost and time to remove and recycle or dispose of any and all lithium batteries, lead seals, mercury switches, and glass/polycarbonate covers.
9. Supplier shall separate meters and module covers (glass or polycarbonate) and recycle or dispose of covers prior to recycling meters.
10. Supplier shall remove and dispose of any ERT's and batteries in accordance with Company waste disposal policies prior to recycling retired meters and modules.
11. Company, at its option, may consider shipping meters and modules containing mercury switches or batteries off-site for processing. If sent off-site, Supplier shall be required to sort meters and modules and palletize for shipment to off-site facility.
12. Supplier shall remove nameplates where applicable and or permanently mask the nameplate, as appropriate.

8.15 Salvage of Retired Meters or Modules

1. Company requires that the residual value of retired meters or modules be returned to Company through one of the following two options:
    a. Contractor Salvage:
        i. Supplier will recycle retired meters and modules and return proceeds as credit to Company.
        ii. Supplier will separate and segregate all environmentally hazardous materials and recycle or dispose of in accordance with Section 8.13 and 8.14.
        iii. The remaining meter and module components will be recycled by Supplier and Supplier will return the value to Company by providing credits on progress payment invoices. Supplier shall detail such credits as a separate line item in invoices to Company, and shall provide documentation supporting such credits upon reasonable request by Company.
        iv. Supplier shall provide a list of all third parties that are utilized for recycling of meters and modules.
        v. Supplier shall provide a copy of all documentation exchanged between Supplier and third party (or buying party) of such equipment or materials.
        vi. Supplier will bear the responsibility for the quantity of meters and modules recycled as compared to the required nightly file containing meters and modules that have been removed from the field for retirement and recycling. Company will bear the risk of price fluctuations in an agreed-upon scrap market index. The recycling revenue less the Contractor's mark-up for handling/expenses/profit shall be credited against the progress payment.

   vii. As part of this RFP, Supplier must state current price per pound that would be paid back to Company for meters and modules.
  b. Company Salvage:
   i. Company will provide recycling containers to Supplier worksites for recycling of retired meters and modules through a third party.
   ii. Supplier will separate and segregate all environmentally hazardous materials and recycle or dispose of in accordance with Section 8.13 and 8.14.
   iii. The remaining meter and modules components will be placed in a Company-provided recycling container for recycling by a third party.

8.16 Requirement to Supply Miscellaneous Materials

1. Company shall provide the required installation materials including but not limited to: seals, rings, locks, and a-base socket adapters.
2. Supplier shall notify Company of its installation material inventory requirements no less than thirty (30) days prior to the scheduled requirement to for field installation.
3. Supplier must participate in inventory planning meetings.

8.17 Lock/Key Management

1. Company will provide Supplier keys for all Company owned locks, lock boxes, and barrel locks for accessing meters and/or locked meter rooms. All keys provided will be tracked and Supplier will be responsible for lost keys.
2. Additional keys that customers have provided to Company for Meter access may also be available from Company Meter Reading Department. Use of keys from the Meter Reading Department shall be coordinated and tracked by Supplier, and all keys shall be returned to Company within forty eight (48) hours.
3. Suppliers may not copy keys.

8.18 Required Skill Sets of Electric Meter Exchangers

1. Company will review Supplier's training program for electric Meter exchangers. Once the training program has been reviewed, Company will approve, ask to amend, or reject.

8.19 Supplier's Management Obligations

1. Supplier shall provide project management of the installation activities in accordance with methods outlined in PMP. Supplier shall:
   a. Establish work scope, schedule, and costs in consultation with Company
   b. Monitor work progress against the agreed-upon plans with Company
   c. Report on progress to Company weekly indicating the assignments issues, completions with respect to assignments and project schedule, ongoing concerns and resolution progress and any new concerns.
2. Supplier to provide staffing for daily dispatching, scheduling of appointments (as needed), electric Meter management/inventory, electric meter and module disposal, and other administrative duties as determined by Supplier.
3. Supplier shall continuously assess and monitor its employee's performance in day-to-day work and customer contact activities and where necessary, remove or retrain/requalify technicians.
4. Supplier shall ensure all relevant safety training sessions are held for field personnel.

8.20 Minimum PPE Requirements

1. All Supplier field personnel shall carry out their work meeting Company PPE requirements. Included, but not limited to, items are:

a. Clothing – 8 cal/cm2 long-sleeve shirt (w/Supplier logo), natural fiber/self-extinguishing clothing elsewhere, including under garments.
b. Appropriate fire rated pants.
c. Gloves – Class 0 gloves for voltages under 600v, leather gloves or equivalent for non-electrical tasks based on Supplier's hazard assessment.
d. Safety glasses - appropriate safety glasses/goggles are required.
e. Safety shoes – steel-toe or equivalent.
f. Hard hats – hard hat with E rating.
g. Face shields – arc-rated face shield or hood appropriate for fault current. (277-480v, 3 phase, etc.).

2. All PPE equipment shall be provided by Supplier.

8.21 Vehicle Signage

1. Supplier shall provide vehicle stickers/magnetic signs approved by Company, identifying Supplier as an authorized contractor of Company and such signage shall be prominently displayed by Supplier at all times during the course of carrying out the work.
2. Supplier vehicles shall be well maintained and in good repair.
3. If vehicles are not Supplier owned, signage shall be removed from exterior of vehicles when not in use on behalf of Company.

8.22 Requirements for Integrating with Supplier Work Order Management Systems if Proposed

1. Company and Supplier will mutually define processes and integrations for the following:
   a. System integration of data transfer from Company systems to Supplier systems to support electric Meter installations as outlined in the requirements herein.
   b. System integration of data transfer from Supplier to Company systems to support completion of electric Meter installations in accordance with the requirements contained herein.
   c. Name of software Supplier will use to manage work orders for which Company will need to create or modify integrations.
   d. Resource titles, tasks, duration, and cost for completing process and integration work.

8.23 Required Security Screening/On-Boarding Procedures

1. Notwithstanding Supplier requirements for security screening and onboarding procedures that are outlined in the Major Supply Agreement, Supplier shall meet the following requirements:
   a. Supplier employees shall not perform any work on behalf of Company or have access to Company's or its customers' property until the employee has successfully passed Company screening processes, required training, and been issued a badge.
   b. Every Supplier employee will be required to follow a screening process that includes completion of request/supply of personal information. Samples of the required documentation are available from Company Sourcing.
   c. Once drug testing results and background screening has been completed and approved, Supplier will provide individual photos for each employee and ID badge requests will be submitted.
   d. Employee ID badges shall be worn at all times and shall be visible at all times and used as a form of identification upon customer request.
   e. All newly hired Supplier employees or its contractors shall be required to complete Company's required compliance training courses within first thirty (30) days of employment.

f. Supplier employees or its contractors shall be required, after employment, to complete any new Company required compliance training courses within thirty (30) days of training being made available.

g. Yearly and on-going compliance training courses are required by Company. If Supplier's employee(s) do not comply with all training courses and due dates, Supplier employee will be immediately off boarded and denied access to Company property and data. This applies to all Supplier personnel on the project regardless of whether or not they are working on Meter sets, networks, software, on site or off site.

8.24 Cyber and Physical Security Requirements

1. Cryptographic key material shall be properly handled, accounted for, and destroyed when appropriate to prevent unauthorized access to Company's network.

8.25 Requirements for All Training Programs

1. Supplier shall provide a copy of its training program outlining the process that will be used to train field technicians to ensure assigned work shall be properly completed in a safe and efficient manner.
2. Supplier training program shall be reviewed by Company to ensure it meet's Company's standards and, if needed, Company will have the right to request changes to the program.

9 Products and Services Warranties

9.1 Definitions

For purposes of this section, the following definitions shall apply. All other capitalized terms not defined in this section shall have the meaning ascribed to them in Appendix 1 (Essential Definitions and Acronyms) of this RFP. In the event of a conflict between the capitalized terms defined and set forth in this section and the defined terms in Appendix 1, the definitions set forth in this section shall control.

1.1 "**Annual Failure Rate**" means (i) the total number of a particular type of Goods having a Defect in any rolling twelve (12) month period divided by the total number of the same type of Goods delivered by Supplier in the rolling twelve (12) month period, or (ii) the total number of a particular type of Goods having a Defect in any Lot divided by the total number of Goods in the Lot.

1.2 "**Defect**" means any material defect in design, manufacturing, materials, workmanship or damage (where the damage is caused by Supplier or by any defect for which Supplier is responsible) in or to, as applicable, the Work, the Goods, or any part thereof.

1.3 "**Epidemic Failure**" means (i) with respect to Integrated Electric Meters, an Annual Failure Rate greater than 0.5%, and (ii) with respect to all other Goods, an Annual Failure Rate greater than 5%.

1.4 "**Goods**" shall include all Goods as defined in Appendix 1 (Essential Definitions and Acronyms) of the RFP.

1.5 "**Extended Goods Warranty Period**" means the period beginning on the date the Standard Goods Warranty expires and ending at the end of any additional warranty period for which Company has paid all applicable fees.

1.6 "**Integrated Electric Meter**" means an electric Meter provided by Supplier into which a NIC compatible with Company's systems has been integrated in accordance with applicable Specifications.

1.8 "**Lot**" means a set of any Goods of the same type with the same manufacturing location and critical components, such as application-specific integrated circuits (ASICs), processors, radios, printed circuit boards (PCB), initial Firmware loaded at time of manufacture, etc.

1.9 "**NIC**" has the meaning set forth in Appendix 1 (Essential Definitions and Acronyms) to this RFP.

1.10 "**Recall Failure**" means (i) an Annual Failure Rate greater than 5% in any particular Goods , (ii) a voluntary recall of any particular Goods (for example, due to safety issues), or (iii) an involuntary recall of any particular Goods (for example, due to a mandate of a Governmental Body).

1.11 "**Services Warranty Period**" means the period commencing on Final Acceptance and ending on the anniversary date one year thereafter.

1.12 "**Standard Goods Warranty**" has the meaning set forth in Section 9.3 (Standard Goods Warranty).

1.13 "**Software**" has the meaning set forth in Appendix 1 (Essential Definitions and Acronyms) to this RFP.

1.15 "**Standard Goods Warranty Period**" means the period commencing on acceptance of the Goods and ending:

(a) for Integrated Electric Meters, thirty six (36) months thereafter; or

(b) for all Goods other than Integrated Electric Meters, twelve (12) months thereafter.

9.2 Services Warranty

9.2.1 Warranty

During the term of the Services Warranty Period, Supplier shall warrant to Company that the Services are performed in accordance with standards of care, skill and diligence consistent with (i) recognized and sound industry practices, procedures and techniques; (ii) all applicable laws and regulations at the time the Services are performed; (iii) the Specifications, documents and procedures applicable to the Services; and (iv) the degree of knowledge, skill and judgment customarily exercised by professional firms with respect to services of a similar nature ("Services Warranty").

9.2.2 Remedy

Supplier shall, at its expense, promptly correct or correctly re-perform any non-conforming Services during the Services Warranty Period. Any corrected or re-performed Services will be warranted with the same scope as the Services Warranty for a period of ninety (90) days after delivery of the corrected or re-performed Services or until the end of the Services Warranty Period, whichever period is longer.

9.3 Software Warranty

9.3.1 Software Warranty

For a period of ninety (90) days from the date a piece of Software is installed and accepted by Company, Supplier shall warrant that the Software will substantially conform in all material respects to its Specifications and Documentation.

9.3.2 Remedy for Breach of Software Warranty

Supplier shall, at its option, during the warranty period described in this Section, repair or replace any non-conforming Software to substantially conform to the foregoing warranty.

9.3.3 Exceptions to Software Warranty

The Software warranty shall not apply to non-conformities in Software due to: (a) misuse or abuse, including the failure to use or install the Software in accordance with the Specifications; or (b) third party software, hardware or firmware not provided or authorized by Supplier in writing.

9.4 Standard Goods Warranty

9.4.1 Warranty

During the Standard Goods Warranty Period, and subject to Company's payment of all Standard Goods Warranty fees, Supplier shall warrant that all Goods (i) will perform in all material respects in accordance with applicable Specifications set out in this Agreement; (ii) will be free from Defects; (iii) on delivery, will be free and clear of any liens, security interests or encumbrances of any nature whatsoever, and (iv) will be produced, processed, delivered and sold or licensed in conformity with all applicable federal, state and local laws, administrative regulations and orders ("Standard Goods Warranty").

9.4.2 Remedy

For any breach of the Standard Goods Warranty, Supplier will, at its option and expense, and during the Standard Goods Warranty Period, promptly repair or replace any non-conforming Goods within fourty five (45) Business Days of Supplier's receipt of the non-conforming Goods and reimburse Company for its reasonable out-of-pocket costs incurred in shipping the Goods to Supplier.

9.5 Extended Warranty for Integrated Electric Meters

9.5.1 Extended Warranty Duration

Supplier shall offer Extended Warranties for Integrated Electric Meters for the following durations:

Standard Warranty Period	Extended Warranty Period	Total Warranty Period
3 years	2 years	5 years
3 years	7 years	10 years
3 years	12 years	15 years
3 years	17 years	20 years

9.5.2 Extended Warranty Scope

Subject to Company's payment of all Extended Goods Warranty fees, Supplier shall provide the same scope of warranty as the Standard Goods Warranty for the duration of the Extended Warranty Period (the "**Extended Warranty**"). Company's remedies for any breach of the Extended Goods Warranty shall be the same as the remedies provided for the Standard Warranty Period.

9.6 Epidemic Failures; Recalls

9.6.1 Warranty

Supplier shall warrant all Integrated Electric Meters against Epidemic Failures and Recall Failures for a period of twenty (20) years after acceptance.

9.6.2 Investigation of Failures

Supplier will, with Company's reasonable assistance, use commercially reasonable efforts to investigate and determine the cause of any Epidemic Failure or Recall Failure. Supplier's investigation shall begin within seven (7) days of receipt of notice from Company of an Epidemic Failure or Recall Failure, or Supplier's discovery of the Epidemic Failure or Recall Failure, whichever occurs earlier. Supplier shall provide a preliminary report of its investigation within (30) days of beginning the investigation.

9.6.3 Corrective Action Plan

The Parties shall work together to promptly establish and implement, at Supplier's expense, a corrective action plan to cure any Epidemic Failures or Recall Failures. If Supplier is unable to remotely repair Goods affected by an Epidemic Failure or a Recall Failure, the corrective action plan shall require, at a minimum, Supplier, at its expense, to:

(a) Repair and/or replace the affected Goods;

(b) Deliver such repaired and/or replaced Goods to Company;

(c) Pay prevailing union labor rates, if union labor is required, or non-union labor rates, if union labor is not required, in the applicable area for labor costs to repair and/or remove and replace such Goods; and

(d) For replacement Integrated Electric Meters, extend the Standard Warranty Period for the remaining life of the Standard Warranty Period to 51 months from shipment of the replaced Integrated Electric Meters.

9.6.4 Suspension

Until an Epidemic Failure or Recall Failure is cured to Company's reasonable satisfaction, Company may suspend all outstanding Purchase Orders, Work Orders, and Releases for any Goods of the same catalog number as the Goods subject to Epidemic Failure.

9.6.5 Monitoring Customer Data

Supplier will monitor data regarding the operation of (i) Supplier's other customers' products similar to Goods, and (ii) Goods ("Customer Data"). Supplier will notify Company if Supplier determines, based on Customer Data, that an Epidemic Failure or a Recall Failure has or is statistically likely to occur.

9.7 Additional Terms

9.7.1 Changes in Good Lots

During the goods installation period, Supplier will notify Company about any new Goods Lots.

9.8 Manufacturer Warranties

9.8.1 Terms

Supplier shall transfer and assign to Company any and all manufacturer warranties regarding any Goods supplied pursuant to this Agreement.

9.9 Exceptions to Warranties

Supplier shall have no liability to Company under this section or any other warranty to the extent such liability was caused by:

a. improper repairs or alterations, misuse, abuse, neglect, negligence, accident, or intentional acts by Company or a third party;

b. modifications made to Goods, Services, and Software without Supplier's prior written approval;

c. operation, maintenance or use of the System, Work, Goods, Software or any component thereof in a manner not in compliance with a material requirement of operation or maintenance manuals delivered by Supplier to Company at the time of delivery of the non-compliant System, Work, Good, Software or any component thereof;

d. normal wear and tear;

e. incorrect data entry or output by Company or a third party not under Supplier's control; or

f. Force Majeure conditions.

9.10 Requirements for Return Material Analysis (RMA)

1. Supplier will perform returned material analysis (RMA) on all returned goods within sixty (60) days of Company's shipment of the returned goods, and, by the fifteenth (15^{th}) day of each month, provide Company an RMA Report that analyzes at aggregate by good type:
    a. Performance and operational issues discovered.
    b. Incremental and cumulative to-date (since model's introduction to Company) quantity of Meters affected.
    c. Initial prognosis, to include specific malfunctioning component to assembled Meter.
    d. Anticipated steps for resolution by Supplier,
    e. On a quarterly basis, beginning on the one (1) year anniversary of the Effective Date, Company and Supplier shall meet to review the results of the equipment failure analyses and develop strategies for addressing recurring Meter performance and operational issues.
2. The same monthly RMA report will have a separate section with specific analysis of each good returned, with none dating further than sixty (60) days prior, and that includes no less than the following for each returned good:
    a. Meter ID
    b. NIC ID
    c. Reason for removal (specific event error code or unsolicited exchange) originally provided by Company
    d. Date that event was generated originally provided by Company
    e. Date removed from field originally provided by Company
    f. Confirmation of agreement to Company's index reading of Meter
    g. Date inspected
    h. Inspector name, ID or test machine ID where appropriate
    i. Problem found
    j. Supplier resolution
3. Any Meter that will be reused by Supplier and be procured by Company will be certified through testing in accordance with Company standards.
4. Supplier will provide As Found metrology and communication test results on electric Meters removed from the field that will be retrofitted for reuse. The results will be provided to Company for further analysis.
5. Supplier will perform an As Left metrology and communication test and calibration of Meters. Meter calibration tests and performance standards will be within Supplier's standards for such Meters. All updated test results shall be sent to Company for updates.
6. Supplier shall identify, diagnose, and determine remedy for all operational and performance issues affected by the Meter and NIC and provide Company with a comprehensive report on all identified issues with.
7. Supplier shall make all reasonable efforts to determine all issues including intermittent ones and not use no trouble found as an appropriate diagnosis. Reasonable efforts shall include but not limited to tests under varying temperature conditions and load over an extended period of time.
8. Supplier shall establish a resolution matrix that identifies responsibilities for how defects associated with Meters versus NIC components shall be addressed. Such a matrix shall be shared with Company before contract execution.

10 Maintenance Support Provisions

10.1 General Requirements

1. Suppliers shall offer support for the life of the product:
   a. Help desk/technical advice.
   b. Service/repair capabilities and,
   c. Equipment replacement supply capabilities.

10.2 Requirements of Supplier

1. Provide staffed help desk offering technical support by telephone with 1-800#, email, and Internet chat advice service during normal business hours 8:00am to 5:00pm local time (Central and Mountain Time).
2. Guarantee of access to a knowledgeable individual by telephone within four (4) hours of a service support request.
3. Maintain a secure web-based bug or issue reporting and tracking system.
4. The primary path to report and manage issues shall be through the customer support group. Supplier support engineers shall help troubleshoot issues, open and track tickets, process requests and route issues to the correct Supplier teams for resolution.
5. On-call and possibly on-site assistance in troubleshooting end-point communication issues.

10.3 Equipment Replacement Supply Capabilities

1. Where replacement equipment is necessary to affect repair, it shall be supplied under the terms of the relevant equipment warranty (Section 9-Supplier's Comprehensive Integrated Meter Warranty).
2. For any field Meter maintenance service requested by Company, not otherwise covered under Warranty terms (Section 9), Supplier shall be in a position to provide maintenance service. Supplier shall deliver services based on Supplier's Exhibit X-Maintenance Program, in accordance with the labor rates in Supplier's Rate Card.

10.4 Ongoing Maintenance

1. For any field Meter maintenance service requested by Company, not otherwise covered under Warranty terms (Section 9 – Supplier's Comprehensive Integrated Meter Warranty), Supplier shall be in a potision to provide maintenance service in the field. Supplier shall provide a separate exhibit describing Supplier's field maintenance program. (Exhibit x-Maintenance Program). Supplier shall provide a rate card including, at a minimum: trades, hourly rates, and travel expenses.

10.5 Training Requirements

10.5.1 On-site Training

1. Supplier shall provide an on-site training program that shall include, but not be limited to: training material, schedule, and topics which shall be offered in a classroom/or web-based as appropriate. Training topics can include operations, diagnostics, maintenance, and installation.
2. Training program shall include classroom or field time as appropriate with an on-site qualified instructor or subject matter expert.

3. Training program shall be for Engineers and Meter Technicians and shall be comprehensive and interactive. Program shall be intended to demonstrate and instruct on the subject of Supplier's hardware, software, and tools.
4. Training shall include field installation, maintenance, and diagnostic demonstrations and an installation manual to grant participants a working knowledge of Supplier's AMI Meters without continuous support by Supplier.
5. Supplier shall work with Company to provide additional time in training courses for training material required for Meter Technicians and Engineers on external communication.
6. Company does not require skills testing and certification for training program.
7. Training shall be set up in modules that will be relevant to different groups within Company.
8. The classroom training shall be supplemented with a set of web training sessions given at flexible times throughout the deployment or in a single or multiple-day live training session.
9. Company may record any training provided by Supplier for use and distribution by Company for internal training purposes.
10. All training material will be provided in a format that is acceptable to Company and stored in a repository for future training purposes.
11. Supplier shall provide train-the-trainer session(s) to transfer knowledge to Company on training material and requirements.
12. On-site training and web training, where applicable, shall cover no less than the following topics:
    a. Theory and design of the supplied Meters.
    b. Operation techniques and features of the Meter.
    c. Hardware design configurations.
    d. Meter firmware update – local and remote.
    e. Meter programming – local and remote.
    f. Diagnostics interpretation for troubleshooting on a daily basis.
    g. Techniques for firmware upgrading including but not limited to Meter metrology and NICs.
    h. Safety issues concerning physical installation and RF.
    i. Cyber and physical security.
    j. Understanding the mounting configuration and operation.
    k. Physical installation techniques.
    l. Electrical connections.
    m. Grounding and lightning protection.
    n. Initial set-up and testing.
    o. Problem-solving and troubleshooting techniques.
    p. Compliance with ECC regulations in the installation and operation.
    q. Field Tool operation and use.
    r. Trouble shooting for the wireless connection.
    s. Diagnostics for meter theft and voltage detection at the socket.

10.5.2 Factory Training

1. Supplier shall offer an optional factory training program. Factory training shall mean training provided at Supplier's site on the use of systems.
2. Factory training shall include additional topics as defined by Company.

10.5.3 Optional Training Modules

1. Supplier shall offer additional or repeat training courses as needed.

11 Appendix 1 – Essential Definitions and Acronyms

Contracting Related, Short Forms, and Acronyms

1. AMI – Advanced Metering Infrastructure (AMI) is architecture for automated, two-way communication between an advanced utility Meter with an IP address and a utility Company.
2. AMI System – The collection of interworking components parts including hardware, software, integration, installation and intellectual content forming the complete functional AMI environment.
3. AGIS – Advanced Grid Intelligence and Security.
4. ATP – Acceptance Test Plan. A document that defines certain technical and operational tests that are required to be completed by Supplier, and witnessed by Company for the purpose of defining a set of technical and operational conditions that must be satisfied. The ATP includes both identification of the required tests and the procedures that are expected to be followed so as to carry out the tests.
5. AQL- Acceptable Quality limit is the worst tolerable process average (mean) in percentage or ratio that is still considered acceptable.
6. Bill Window – Three (3) business days from the date Meter reading routes are available to be read by cycle. Each route has a specific date it becomes available to be read. For example, Cycle 1 for May 2017 was first available to be read on 04/28/2017 and therefore the three business day window would run from 4/28/2017 to 05/02/2017. Meter can be read anytime during the three business day window. Company has 22 read cycles.
7. Blocks – Geographically defined areas of land delineating territory for electric service that is offered by Company.
8. BOM – Bill of Materials.
9. Company – As defined in the Agreement.
10. Company Security Standards – The standards defined in Appendix 2.
11. Contractor – Company or personnel hired by Supplier as contractors.
12. Cost Take Out – Any trackable effort to reduce soft or hard cost associated with this multiyear project resulting in the benefit of optimized service, hardware, support, maintenance and/or warranty for Company or both parties.
13. DA – Distribution Automation. In this document, DA refers to the control aspects of electric field automation, often referred to in the context of SCADA systems.
14. DA System – The collection of interworking components parts including hardware, software, integration, installation and intellectual content forming the complete functional control and monitoring environment for various forms of electric distribution system automation.
15. Design – The plan and assembly of equipment for implementation/construction of the system components including engineering drawings, parts, circuit diagrams, etc.
16. Document – A solicitation made through a bidding process by Company in procurement of a commodity, service, or valuable asset, to potential Suppliers to submit business proposals.
17. Engagement Manager – The fully qualified and experienced Supplier individual having the responsibility for the business and financial aspects of the project.
18. Failure, as related to AMI Loss of Communication – Where any devices are intended to communicate and they cannot communicate or any reason, it has failed.
19. Failure, as related to AMI Meter Accuracy – If it is not within specified parameters set out herein, it has failed.
20. Field Work – The performance of maintenance on Meters performed by Supplier on behalf of Company.
21. Field Work Orders – Company-generated order requiring Supplier to perform Field Work.
22. Functional Requirements – What the system does. This would include general descriptions of features, capabilities, information, etc.
23. Gantt Chart– A project management oriented graphical presentation that is prepared to illustrate predicted and (later) actual start and finish dates of the elements of the project. A Gantt chart visually presents project elements, timelines for start and completion and the critical components, all of which are

useful to identify, monitor and manage, so as to gain successful project completion against a well-defined) scope, schedule, and cost.

24. Goods - Supplier hardware and related accessories and other personal property (except Documents)
25. Head-end – A system of hardware and software that receives streams of data brought back to utility through the AMI system.
26. INS - Itron Networked Solutions.
27. ISOW – Independent Statement of Work.
28. Meters – Electric AMI Meters.
29. MSOW – Master Statement of Work.
30. Mobile Computing Environment – Company's Mobile Computing Environment, the wireless network environment utilized to collect, manage, and communicate information in performing Field Work and which is capable of interfacing with Company's software and applications, including, without limitation, MDMS and CRS.
31. MOU – Memorandum of Understanding.
32. MPS – Master Pricing Schedule.
33. MTS – Master Test Strategy.
34. MFC – Most Favored Customer.
35. NOC – Network Operations Center.
36. Non-Functional Requirements – Description of the system, such as constraints, usability, reliability, performance, capacity, and supportability.
37. NSPM – Northern States Power Minnesota.
38. NSPW – Northern States Power Wisconsin.
39. OEM – Original Manufactured Equipment.
40. OPCo – Operating Company.
41. Pert Chart – A project management oriented graphical presentation that is prepared to illustrate the relationship of tasks or project elements as they relate to project flow from commencement to completion over the project lifecycle.
42. PMP – Project Management Professional, as recognized by the Project Management Institute (see PMI.org).
43. Project Manager – Fully qualified and experienced individual both from Supplier and Company having the responsibility for the planning, execution and closing of the project.
44. PSCo – Public Service Company of Colorado.
45. RFP – Request For Proposal.
46. Services – Includes Meter installation or exchange services.
47. Single Phase Underground Installation – Termination at the pedestal and installation of Meter at the customer facility in accordance with Company standards.
48. Special Meter Reading – Retrieval by Supplier and delivery to Company of data from Meters designated by Company. Special Readings are typically generated because of End User billing disputes or generated Meter events.
49. SPS – Southwest Public Service.
50. SOW – Statement of Work. The document that defines the necessary work activities and obligations by Supplier and that forms part of binding contractual conditions of Supplier.
51. Supplier – A Corporate entity that is proposing to supply equipment and Services in response to this Request for Proposal.
52. Survey Meters – Meters specifically configured to collect load profile data for load research purposes.
53. SSA – Support Services Agreement.
54. SSN – Silver Spring Networks, now known as Itron Networked Solutions.

Technical Related, Short Forms, and Acronyms

1. 6LowPAN – IPv6 over Low power Wireless Personal Area Networks.

2. ADA – Advanced Distribution Automation. Systems that apply modern computational and communications techniques to intelligently control electrical power grid functions to the distribution level and beyond.
3. ADMS – Advanced Distribution System Management System. A unified DMS, SCADA, OMS AND EMS solution that provides utilities with a modular and flexible platform within a common user experience, data model, integration framework, and secure infrastructure.
4. Advanced Grid – (From the Office of Electricity Delivery and Energy Reliability) a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation.
5. AES-256 – Advanced Encryption Standard. Standard to protect classified information; implemented in software and hardware to encrypt sensitive data.
6. Aggregator – System that collects AMI data.
7. Automated Sectionalizing – Systems used by utility electric distribution and transmission operators to perform circuit sectionalizing by means of remote control of a variety of different protective devices installed across the electric grid for the purpose of protecting the system from damaging fault currents and minimizing the time and number of consumers experiencing an outage.
8. AMI Meter – Combination of Meter metrology, register, and communication.
9. AMI Meter Failure – Any failure of Meter/Network Interface Card to perform its function within specifications.
10. Back Office – A suite of applications, supplied by Supplier that are deployed on a standards-based Critical Infrastructure Networking Platform. The applications enable utilities to support multiple advanced grid applications on common infrastructure. The Back Office Systems application suite includes utility applications for advanced grid initiatives as well as network administration software for configuring, upgrading, and managing the advanced utility network.
11. B.E. – Best effort.
12. BER – Bit Error Rate.
13. Border Router – A NAN defined WMN routing deployment-ready platform for interconnecting IP and 6LoWPAN networks. It assumes an Ethernet interface on the IP side and an 802.15.4g interface on the 6LoWPAN side.
14. CDF – Cumulative Distribution Function; a useful means to quantify statistical network performance metrics. In probability theory and statistics, CDF of a real-valued random variable X, or just distribution function of X, evaluated at X, is the probability that X will take a value less than or equal to X.
15. CPI – Consumer Price Index
16. CRS – Company's computer system designed to generate End User bills, collect information regarding End Users, monitor End User complaints, and disseminate information to End Users.
17. CSS – Customer Service System.
18. CVR – Conservation Voltage Regulation. Systems that facilitate controlled reduction in the voltages received by an energy consumer to reduce energy use, power demand, and reactive power demand.
19. CPE – Customer Premise Equipment, used in the context of WiMAX, formally defined as Subscriber Station component of a WiMAX system.
20. CPP – Critical Peak Pricing rate offering.
21. CT – Instrument Current Transformer.
22. Customer Outage – Customer interruption of service.
23. C&I – Commercial and Industrial Customers.
24. DER – Distributed Energy Resources. Decentralized energy that is generated or stored by a variety of small, grid-connected devices such as solar, wind, or battery.
25. DA – Distribution Automation. In this document, DA refers to the control aspects of electric field automation, often referred to in the context of SCADA systems.
26. DG – Distributed Generation.
27. DMS – Distribution Management Systems. A collection of applications designed to monitor and control the entire distribution network efficiently and reliably.
28. DSCP – Differentiated Services Code Point.

29. DR – Demand Response. (From the Federal Energy Regulatory Commission) is defined as "Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized".
30. ERT – Encoder Reciever and Transmitter.
31. ESP – Energy Service Portal.
32. EV Charging – Electric Vehicle battery charging systems. Systems that are used to charge the batteries of electric vehicles, sourcing energy over the grid.
33. FAN – Field Area Network. A collection of (usually) wireless networks, operating over a large geographic area for the purpose of providing data services.
34. FAST AMI – Meter read rates for all Meters, excluding bellwether Meters, shall record interval, register and events data every fifteen (15) minutes and complete transmission of this recorded data to the Head-end, at an interval that does not exceed every fifteen (15) minutes.
35. FAT – First Article Testing.
36. FLISR – Fault Location Isolation and System Restoration. Combines hardware, software, telecommunications, and grid engineering to decrease the duration and number of customers affected by any specific outage.
37. Field Communication Tool – The devices and instruments that are used by AMI field personnel to communicate wirelessly, over the air to electric Meters and network.
38. HAN – Home Area Network.
39. HTTPS – Secure version of Hypertext Transfer Protocol (HTTP), using SSL.
40. IEEE – Institute of Electrical and Electronics Engineers. A professional association dedicated to advancing technological innovation and excellence for the benefit of humanity. In Company context, IEEE defines standards for wired and wireless communications.
41. IETF – Stands for Internet Engineering Task Force, a large open international community of network designers, operators, vendors and researchers concerned with the evolution of the Internet architecture
42. IHD – In Home Display.
43. IoT- Internet of Things
44. IP – Internet Protocol address is a numerical label assigned to each device such as computer and printer participating in a network that uses internet protocol communication.
45. IPv6 – Internet Protocol version 6 is the most recent version of the Internet Protocol (IP), the communication protocol that provides and identification and location system for computers on networks and routes traffic across the Internet.
46. ISOW – Individual Statement of Work.
47. ISP – Internet Service Provider.
48. IT – Information Technology, the use of systems (especially computers and telecommunications) for storing, retrieving, and sending information.
49. IVVO – Integrated Volt/VAR Optimization, Voltage/Voltage-Ampere Reactive Optimization. A suite of modern control technologies that use extensive sensor data, wireless communication links, and computational control systems to increase grid visibility and efficiency. Generally, IVVO technology operates by gathering extensive performance metrics on power lines and equipment through a wireless network, then adjusts and optimizes system performance through data analysis and control actions.
50. JTAG – Joint Test Action Group. An electronics industry association for developing a method of verifying designs and testing printed circuit boards after Supplier.
51. KYZ – Electronic pulses used to represent amount of energy consumed.
52. LAN – Local Area Network.
53. Logging – Recording and storage of data.
54. LOT – A group of homogeneous devices where the selection of the devices in the LOT is based upon one or more specific criteria such as operating company (i.e., PSCo), Supplier, Meter model, Meter form, Meter class, age, or any other attribute as required for analysis purposes.
55. LP – Load Profile Data.
56. MAIFE – Momentary Average Interruption Frequency Index Event.

57. MAIFI – Momentary Average Interruption Frequency Index.
58. MDM – Meter Device Management.
59. MDMS – Monitoring Device Management System; Company lifecycle asset system.
60. Momentary Interruption – The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device. NOTE: Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions.
61. Momentary Interruption Event – An interruption of duration limited to the period required to restore service by an interrupting device. NOTE 1: Such switching operations must be completed within a specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. NOTE 2: If a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.
62. MCE – Mobile Computing Environment.
63. MDT –Mobile Data Terminal. Could be a notebook/laptop or field tool used by field personnel for completion of assigned work.
64. Module – Itron ERT or Landis+Gyr AMR interface units.
65. MSOW – Master Statement of Work.
66. MTTR – Mean Time to Repair.
67. NAN – Neighborhood Area Network.
68. NIC – Network Interface Card.
69. NMS – Network Management Systems. Electronic systems consisting of hardware and software used in the setup, configuration, dimensioning, management, and monitoring of data networks.
70. NTP – Network Time Protocol. Internet protocol used to synchronize computer clocks to a time reference.
71. OEM – Original Equipment Manufacturer.
72. OMS – Outage Management System. A computer system used by operators of electric distribution systems to assist in restoration of power.
73. OSI – Open Systems Interconnection model (OSI model) is a conceptual model that characterizes and standardizes the communication functions of a telecommunication or computing system without regard to their underlying internal structure and technology.
74. OWASP – Open Web Application Security Project. Organization focused on improving security of software.
75. Outage – Per IEEE definition of outage, is the loss of ability of a component to deliver power.
76. P2MP – Point to Multipoint Radio Systems. A wireless radio system that generally consists of a single base station that communicates virtually with multiple endpoints.
77. P2P – Point to Point Radio Systems. Wireless radio systems that enable wireless communications circuit between two distinct endpoints.
78. PEN – Penetration testing is the practice of testing computer and network systems to find vulnerabilities that could be exploited.
79. PHY – In networking terms, a short form for the component that operates at the physical layer of the OSI layer of the OSI network model.
80. PII – Personally Identifiable Information. Information that can be used on its own or with other information to identify, contact, or locate a single person, or to identify an individual in context.
81. PKI – Public Key Infrastructure. A set of roles, policies, and procedures needed to create, manage, distribute, use, store, and revoke digital certificates and manage public key encryption.
82. PPE – Personal protective equipment.
83. PTR – Peak Time Rebate rate offering.
84. PQ – Power Quality.
85. PTJ – Process Tracking Job.
86. QoS – Quality of Service.
87. RAM – Random Access Memory.
88. RF – Radio Frequency.
89. RMA – Return Material Analysis.
90. RSSI – Received Signal Strength Indicator.

91. RTT – Round Trip Time. The length of time it takes for a signal to be sent plus the length of time it takes for an acknowledgment of that signal to be received.
92. RTU – Return To Utility.
93. SAP – Systems, Applications, and Products in Data Processing is a German multinational software corporation that makes enterprise software to manage business operations and customer relations.
94. SC – Self Contained Meters.
95. SCADA – Supervisory Control and Data Acquisition; Systems used for remote monitoring and control that operate with data signals over communication channels.
96. SEP – Smart Energy Profile.
97. SFTP – Protocol for file transfer over SSH (secure shell)
98. SIEM – Security Information and Event Management. Software products and services that provide real-time analysis of security alerts generated by applications and network hardware.
99. SMA – Sub Miniature version A type connector. A semi-precision coaxial RF connector having a 50 Ω impedance.
100. SNMP – Simple Network Management Protocol is an Internet-standard protocol for collecting and organizing information about managed devices on IP networks and for modifying that information to change device behavior. Devices that typically support SNMP include cable modems, routers, switches, servers, workstations, printers, and more.
101. SNR – Signal to Noise Ratio.
102. Soft Key – Mechanisms by which built-in factory features/hardware can selectively be enabled using separately purchased authorizations.
103. Software - Supplier's proprietary software.
104. Solicited Field Work – Field work requested by Company and performed by Supplier or Supplier Contractor.
105. SSH – Secure Shell
106. SSL – Secure Sockets Layer
107. SUN – Smart Utility Network. Networks that are compliant to IEEE 802.15 Smart Utility Networks (SUN) Task Group 4g, consisting of a PHY amendment to 802.15.4, and providing a global standard that facilitates very large scale process control applications such as the utility smart-grid network capable of supporting large, geographically diverse networks with minimal infrastructure, with potentially millions of fixed endpoints.
108. TCP/IP – Transmission Control Protocol/Internet Protocol. Suite of communication protocols used to interconnect network devices on the Internet.
109. TLS – Transport Layer Security
110. TOU – Time of Use rate offering.
111. T-Min – Minimum time.
112. T-Max – Maximum time.
113. TVHD – Total Voltage Harmonic Distortion.
114. UI – User Interface.
115. Un-solicited – Work peformed by Supplier or Contractor without request from Company.
116. TR – Transformer rated Meters.
117. VT – Instrument Voltage Transformer.
118. FAN – Field Area Network
119. WMN – Wireless Mesh Network. Refers to any wireless network that operates in a topology in which endpoint mesh nodes cooperate in the distribution of data, relaying information between neighbors. NAN is an example of a WMN. In the context of Company, WMN shall mean equipment and services that are necessary to implement a SUN compliant network.
120. WiMAX CPE or CPE – Customer Premise Equipment, referring to the wireless endpoint equipment on a WiMAX system (although the term may be generalized to other wired or wireless systems). It generally consists of an antenna and transmission line feed system as well as the electronics unit which may be placed inside or exterior to a building (dwelling) or enclosure.
121. WIMAX – Interoperable implementations of the IEEE 802.16 family of wireless-networks standards ratified by the WiMAX Forum.

122. Zigbee - IEEE 802.15.4 based specification Wireless communications protocols used to create personal areas networks.

12 Appendix 2 – IT Standards

IT Standards

Hardware/Device/ Application/Tool/Software	Xcel Standard	Notes
CISCO Flexpod	Series B, Series C	Current version is "CORE" stage of the Standards Lifecycle.
CISCO NetApp Filer (Storage)		Current version is "CORE" stage of the Standards Lifecycle.
Redhat Linux Enterprise Edition Server	7.2	Current version is "CORE" stage of the Standards Lifecycle.
Microsoft Windows Server 2016	2016	Version is "Strategic" stage of the Standards Lifecycle.
Microsoft SCCM	7	Version is “Declining” stage of the Standards Lifecycle
Microsoft Windows 10 *(IE 11/Chrome 24+)*	7	Version is "Strategic" stage of the Standards Lifecycle.
Microsoft SQL Server 2016	2016	Current version is "CORE" stage of the Standards Lifecycle.
Backup (Symantec NetBackup)	7.7.2	Version is in “CORE” stage of the Standards Lifecycle.
McAfee Anti-Virus	8.8	Version is in “CORE” stage of the Standards Lifecycle.
CheckPoint Firewall	R80.10, R80.00, R77.30, R77.20	Version is in “CORE” stage of the Standards Lifecycle.
AD/AD LDS	69/31	Version is "Strategic" stage of the Standards Lifecycle.
Terminal Services	2016	Version is "Strategic" stage of the Standards Lifecycle.
ESXi	6.x	Version is "Strategic" stage of the Standards Lifecycle.

SCCM	2016	Version is in "Strategic" stage of the Standards Lifecycle.
CyberArk Password Vault	8.2	Current Standard is CORE for this version.
IBM Integration Bus	IIB 10	Version is in "Strategic" stage of the Standards Lifecycle.
Oracle Database EE on Exadata version X6-2	12.c	Version is in "CORE" stage of the Standards Lifecycle.
Information Model Exchange	CIM	
PING Fed	7.3	Version is in "CORE" stage of the Standards Lifecycle.
Web Traffic	https	Version is in "CORE" stage of the Standards Lifecycle.

13 Appendix 3 – PSCo Electric Meter Deployment (Preliminary)

PSCo Electric Meter Deployment

Block	Quarter	Branches	Meter Count	General Location
Block 1	2019 Q4	DM, NM, SE, SW	15,881	Bellwether meter deployment, mainly in metro Denver (Denver)
Block 2	2020 Q1	DM, SW	39,227	South and Southwest of Downtown Denver (Denver)
Block 3	2020 Q2	DM, SW	40,373	SW of DT Denver, along Sixth Avenue (Lakewood)
Block 4	2020 Q3	SW, NO	38,723	Along Sixth Avenue, intersection of I-70 and US 6 (Lakewood and Golden)
Block 5	2020 Q4		40,492	Along I-70, West of DT Denver (Wheat Ridge, Edgewater, and Arvada)
Block 6	2021 Q1	SW, NO, DM, SE	100,840	West, South, and East of DT Denver (Denver and Edgewater)
Block 7	2021 Q2	SE, SW, DM	99,944	SE of DT Denver along Parker Road (Denver, Glendale, and Aurora)
Block 8	2021 Q3	SW, SE	105,057	S of Colfax along 225, along Hampden and Belleview to Wadsworth. (Aurora, Cherry Hills Village, Greenwood Village, Sheridan, Littleton, Bow Mar)
Block 9	2021 Q4	SW	98,766	SW, S of Evans along 470 to University (Morrison, Littleton)
Block 10	2022 Q1	SW, SE	116,647	S of 470, S of 225 out to Parker Road (Highlands Ranch, Centennial, Lone Tree)
Block 11	2022 Q2	SE	115,904	E of Parker Road, E of 225, E of Peoria, up to DIA (Aurora, Watkins, Parker, Denver)
Block 12	2022 Q3	DM, NO	127,449	N of Colfax, along I-70, East, North, and Northeast of DT Denver (Denver, Commerce City, Arvada, Thornton, Dupont)
Block 13	2022 Q4	NO	121,023	N of I-70, from foothills to I-76, S of 104th. (Northglenn, Thornton, Westminster, Commerce City)
Block 14	2023 Q1	NO, DM, BD	115,090	DT Denver, N of 104th (Henderson, Brighton, Broomfield, NorthGlenn), Boulder Division around Broomfield
Block 15	2023 Q2	BD, HL	120,324	Boulder county, Greeley
Block 16	2023 Q3	100% of Evergreen, Silverthorne, Vail, Leadville, Salida, and Alamosa. 48% of Fort Collins.	110,246	I-70 to Evergreen to Silverthorne to Vail. US-24 to Leadville to Salida and then to SLV/Alamosa. Start Fort Collins
Block 17	2023 Q4	52% of Fort Collins. 100% Brush, Sterling, and Grand Junction	96,880	Fort Collins, then along I-76 to Brush and then Sterling. Grand Junction
Block 18	2024 Q1	100% Rifle	17,172	Rifle

Block 19	**2024 Q2**			**Empty**
Subtotal			**1,520,038**	**Excludes electric meters inside Boulder**
City of Boulder	**?**	**BD**	**67,574**	**All electric meters inside city of Boulder**
Total			**1,587,612**	**All electric meters in PSCO**

14 Appendix 4 – PSCo Electric Meter Purchasing Schedule (Preliminary)

PSCo Electric Meter Purchasing Schedule

						Arrival comparison to planned deployment						
		Orange= Commulative Installment goal					Green = Commulative meter arrival					
	Jan	Feb	Mar	Apl	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2018												
2019			0	0	0	0	1200	7200	13200	21200	29200	37200
												15881
2020	57200	77200	97200	115200	133200	151200	169200	179200	189200	201200	213200	223200
			54521			94857			132459			171611
2021	238200	250200	286200	322200	358200	414200	470200	526200	582200	600200	618200	636200
			272421			372211			472755			570490
2022	660200	684200	708200	744200	780200	816200	852200	908200	964200	1019200	1063200	1107200
			697691			809159			930182			1048106
2023	1149200	1173200	1237200	1281200	1325200	1353200	1397200	1425200	1469200	1497200	1519200	1529200
			1161217			1276251			1391104			1506794
2024	1551200	1559200	1567200	1575200	1583200	1588000						
			1546979			1587607						

15 Appendix 5 – Meter Calibration File Format

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

Attachment 4C contains protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b), Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a) and are marked as "NOT PUBLIC." The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy.

Attachment 4C provided with the NOT PUBLIC version of this filing contain information classified as trade secret pursuant to Minn. Stat. § 13.37 for the above-noted reasons and are marked as "NOT PUBLIC" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment 4C:

1. **Nature of the Material**: Attachment 4C is an internal assessment summaries that the Company has designated as Trade Secret information in their entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released.
2. **Authors:** This summary was prepared by Business Systems and Sourcing employees and their representatives in 2017, in conjunction with the Company's review of hardware and software needs for its Advanced Metering Infrastructure (AMI) and Field Area Network (FAN) projects, respectively.
3. **Importance:** This Attachment contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because these overall analyses derive independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.
4. **Date the Information was Prepared**: 2017

PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED

Attachment 4D contains protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b), Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a) and are marked as "NOT PUBLIC." The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy.

Attachment 4D provided with the NOT PUBLIC version of this filing contain information classified as trade secret pursuant to Minn. Stat. § 13.37 for the above-noted reasons and are marked as "NOT PUBLIC" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment 4D:

1. **Nature of the Material**: Attachment 4D is an internal assessment summary that the Company has designated as Trade Secret information in its entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released.
2. **Authors**: This summary was prepared by Major Products & Programs Sourcing employees and their representatives in 2019.
3. **Importance**: This Schedule contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because this overall analysis derives independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret.
4. **Date the Information was Prepared**: This assessment was prepared in second quarter of 2019.

Overview and Bidder Instructions

Dear Bidder,

You have been invited by Xcel Energy Services Inc. (hereinafter referred to as “Xcel Energy”) to submit information in response to a request proposal (“RFX”). This document contains important information about Xcel Energy and the RFX and we suggest you take the time to read it carefully. We look forward to your proposal submission using our electronic sourcing system (the “eSourcing System”).

Thank you.

About Xcel Energy at www.xcelenergy.com

Our name reflects our core value — excellence in energy products and services. We are dedicated to providing you the best in service, value and information to enhance your professional and personal life. We are committed to customer satisfaction by continuously improving our operations to be a low-cost, reliable, environmentally sound energy provider. We have been successfully proving this to our customers for more than 130 years and will work hard to continue with this commitment in the future.

As a leading combination electricity and natural gas energy company, we offer a comprehensive portfolio of energy-related products and services to 3.4 million electricity customers and 1.9 million natural gas customers.

We have regulated operations in 8 Western and Midwestern states, and revenue of more than $9 billion annually; and own more than 35,000 miles of natural gas pipelines. We are proud of our community involvement. Through the Xcel Energy Foundation, our economic development activities, and employee volunteer efforts, we are committed to using our considerable resources and skills to benefit the communities we serve.

Our environmental policy states that Xcel Energy will be valued as a leader in the energy industry by demonstrating excellence in environmental performance. The most recent National Renewable Energy Lab's ranking of green pricing programs ranked our Windsource® and Renewable Energy Trust first in number of customers and fifth in energy sales out of over 500 U.S. utilities. Our key environmental commitment includes improving air quality, conserving resources, harnessing renewable energy, and protecting wildlife and habitats.

Proposal Evaluation Criteria

Xcel Energy’s objective in sourcing via the eSourcing System, Emptoris, is to obtain goods and services that best meet technical and functional requirements at the best price. Proposals will be evaluated by Xcel Energy on the basis of the information provided by you through the eSourcing System. The lowest price proposal may not indicate the best overall evaluated proposal. The following criteria may be used by Xcel Energy in its consideration (not necessarily listed in order of importance):

- Bidder’s understanding of and responsiveness to the scope of work, technical specifications and other requirements
- General feasibility of the bidder’s plan to meet the requirements of the scope of work and/or technical specifications
- Bidder’s ability to meet the stated work schedule
- Bidder's acceptance of the general terms and conditions
- Bidder’s experience with similar work and safety record
- The evaluated total cost of the services and/or goods
- The quality of services offered by the bidder

- Comprehensiveness of the bidder's proposal, including options
- Bidder's diversity classification or utilization of diverse suppliers as subcontractors; and demonstration that bidder has made good faith efforts to provide maximum practicable subcontracting opportunities to diverse suppliers

Bidding Instructions

Failure to comply with these bidding instructions may disqualify a bidder from further consideration.

- Xcel Energy requires that all bidders (and their subcontractors, alliances, or partners) provide a single point of contact during the RFX process.
- In the eSourcing System, click on the green **"Accept"** button to indicate your intention to respond or click the red **"Decline"** button to indicate your intention not to respond. During the course of your review and response you can indicate that you wish to not proceed further.
- Correspondence or questions concerning the RFX content and attachments **must be sent using the eSourcing System's messaging functionality** to the Xcel Energy Sourcing & Purchasing Contact / ("Event Owner"). The name of the "Event Owner" is listed in the upper left hand corner of the RFX, labeled as "Contact Information". Instructions on how to send messages are provided in the computer based training module titled *Using System Messaging*. All responses to technical questions will be answered via the eSourcing System's messaging functionality to the RFX and issued to all bidders. Contacting anyone besides the Event Owner about this RFX may be grounds for disqualification.
- All bidding, both qualitative and quantitative, will be submitted through the eSourcing System. You will be asked to answer a number of questions, including pricing on items.
- All submissions must be submitted on time per the schedule indentified in the RFX. Late submittals will not be accepted.
- All submissions must be complete in order to be evaluated. **Incomplete submissions will not be accepted.** The bidder's proposal must be all-inclusive to provide complete and reliable services and/or goods to meet the requirements and technical specifications documented in the RFX.
- The bidder shall not alter any part of the RFX in any way except by stating all exceptions in a response to the appropriate question or as an attachment to the appropriate question with a detailed explanation for each exception.
- Any modification made to the RFX by Xcel Energy will be made through the eSourcing System.
- The bidder shall separately state in its proposal all taxes (including sales, use, and other excise taxes) it believes to be imposed by law upon the transfer of equipment or other materials to Xcel Energy or upon the provision of services. Please contact the Event Owner for applicable tax rates.
- If you have difficulties with the eSourcing System, you may contact the Xcel Energy Supply Chain Hotline at 303-628-2644 from 8:00 a.m. to 5:00 p.m. (MST) Monday through Friday.

RFX Terms and Conditions

In addition to the terms and conditions you accepted on the eSourcing System login screen, the following terms and conditions apply to the RFX:

- **Bidder's submission of proposal information in response to this RFX shall constitute bidder's agreement to these terms and conditions.**
- All costs associated with bid preparation and the provision of related documents are to be borne by the bidder.

- Xcel Energy reserves the right to open proposals privately and unannounced, and to be the sole and final judge of all proposals.
- Bidder's proposal is genuine and not made in the interest of or on behalf of any undisclosed person, firm, or corporation and is not submitted in conformity with any agreement or rules of any group, association, organization, or corporation; bidder has not directly or indirectly induced or solicited any other bidder to submit a false or sham proposal; bidder has not solicited or induced any person, firm, or a corporation to refrain from bidding; and bidder has not sought by collusion to obtain for itself any advantage over any other bidder or over Xcel Energy.
- Bidders shall take no advantage of any apparent errors or omissions in any related documents. If a bidder believes there are errors or omissions in supplied documentation or if the bidder is in doubt as to the meaning of any part of the documentation, bidder is to contact the Event Owner via the eSourcing System's messaging functionality before the close of the RFX. If Xcel Energy agrees that a change is required or if any explanation or interpretation is required, Xcel Energy will modify the RFX and notify bidders via the eSourcing System messaging functionality.
- **Bidders must clearly document exceptions or clarifications to the general conditions in its response to the RFX.**
- The bidder agrees that, if its proposal is accepted, it will remove taxes from any charges to Xcel Energy upon receipt of a properly completed exemption certificate or direct pay tax license number. Except with respect to taxes imposed by law upon the transfer of equipment or other materials to Xcel Energy, the bidder shall pay all other taxes, tariffs, import duties, entry fees, permit fees, license fees, and other charges of any kind incurred in performing the activities contemplated by its proposal; and all such expenses shall be included in the price. If the bidder is in doubt about whether it may incur any such expense, and it would reduce its charges to Xcel Energy by the amount of such expense in the event such expense is not incurred, then the bidder shall explain the nature and amount (if known) of any such expense in its proposal.
- Xcel Energy reserves the right to reject any or all proposals, including without limitation the rights to reject any or all nonconforming, non-responsive, irregular or conditional proposals and to reject the proposal of any bidder if Xcel Energy believes that it would not be in the its best interest to make an award to that bidder. Bidder agrees that any such rejection shall be without liability on the part of Xcel Energy nor shall bidder seek any recourse of any kind against Xcel Energy because of such rejection.
- Xcel Energy may enter into discussions with the bidder proposing the best overall evaluated offer on the terms of the attached general conditions, scope of work and/or technical specifications, and other attachments.
- All proposals shall become the property of Xcel Energy.

Additional Information

For additional eSourcing System information, visit
http://www.xcelenergy.com/Energy_Partners/Sourcing_and_Purchasing_Process

Xcel Energy®

Advanced Metering Infrastructure

Request for Proposal v10

July 18th, 2016

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Essential Definitions

1 Essential Definitions used in this RFP

1.1 Contracting Related, Short Forms and Acronyms

1. AMI –Advanced Metering Infrastructure (AMI) is architecture for automated, two-way communication between an advanced utility meter with an IP address and a utility Company.
2. AMI System –The collection of interworking components parts including hardware, software, integration, installation and intellectual content forming the complete functional AMI environment.
3. AGIS- Advanced Grid Intelligence and Security
4. ATP – Acceptance Test Plan; A document that defines certain technical and operational tests that are required to be completed by the Supplier, and witnessed by Company for the purpose of defining a set of technical and operational conditions that must be satisfied. The ATP includes both identification of the required tests and the procedures that are expected to be followed so as to carry out the tests.
5. Company – The legal corporate entity of Xcel Energy Inc.
6. Cost take out - any track able effort to reduce soft or hard cost associated with this multiyear project resulting in the benefit of optimized service, hardware, support, maintenance and/or warranty for Company or both parties.
7. Coverage Blocks–Geographically defined areas of land delineating territory for electric and gas service that is offered by Company.
8. DA – Distribution Automation – in this RFP, DA refers to the control aspects of electric and gas field automation, often referred to in the context of SCADA systems.
9. DA system –The collection of interworking components parts including hardware, software, integration, installation and intellectual content forming the complete functional control and monitoring environment for various forms of electric or gas distribution system automation.
10. Design –The plan and assembly of equipment for implementation/ construction of the system components including engineering drawings, parts, circuit diagrams, etc.
11. Engagement Manager – shall mean: the– The fully qualified and experienced Supplier individual having the responsibility for the business and financial aspects of the project.
12. Functional Requirements – What the system does. This would include general descriptions of features, capabilities, information, etc.
13. Gantt Chart– A project management oriented graphical presentation that is prepared to illustrate predicted and (later) actual start and finish dates of the elements of the project. A Gantt chart visually presents project elements, timelines for start and completion and the critical components, all of which are useful to identify, monitor and manage, so as to gain successful project completion against a well-defined scope, schedule and cost.
14. Headend – A system of hardware and software that receives stream of data brought back to utility through the AMI system.
15. Non-Functional Requirements – Shall mean: description of the system, such as constraints, usability, reliability, performance, capacity, and supportability.
16. Project Manager – the fully qualified and experienced individual both from Supplier and Company having the responsibility for the planning, execution and closing of the project.
17. PMP – shall mean Project Management Professional, as recognized by the Project Management Institute; see PMI.org
18. Pert Chart – A project management oriented graphical presentation that is prepared to illustrate the relationship of tasks or project elements as they relate to project flow from commencement to completion over the project lifecycle.
19. RFP – Is a solicitation made through a bidding process by the company in procurement of a commodity, service or valuable asset, to potential Suppliers to submit business proposals.
20. SoW – Statement of Work; the document that defines the necessary work activities and obligations by the Supplier and that forms part of binding contractual conditions of the Supplier.
21. Supplier –A Corporate entity that is proposing to supply equipment and Services in response to this Request For Proposal

22. SSA – Support Services Agreement
23. WBS – Work Breakdown Structure; WBS consists of a hierarchically organized list of tasks or "items to be completed" or delivered, prior to completing a project. It is a useful framework for defining overall activities and tasks that are necessary to estimate a project scope, schedule and cost.
24. WRT – With Respect To

1.2 Technical Related, Short Forms and Acronyms

1. 6LowPAN - IPv6 over Low power Wireless Personal Area Networks.
2. ADA – Advanced Distribution Automation; Systems that apply modern computational and communications techniques to intelligently control electrical power grid functions to the distribution level and beyond.
3. Advanced Grid – (From the Office of Electricity Delivery and Energy Reliability) a class of technology people are using to bring utility electricity delivery systems into the 21st century, using computer-based remote control and automation.
4. ADMS – Advanced Distribution System Management System is a unified DMS, SCADA, OMS AND EMS solution that provides utilities with a modular and flexible platform within a common user experience, data model, integration framework and secure infrastructure.
5. Aggregators – System that collects AMI data
6. Automated Sectionalization – Systems used by utility electric distribution and transmission operators to perform circuit Sectionalizing by means of remote control of a variety of different protective devices installed across the electric grid for the purpose of protecting the system from damaging fault currents and minimizing the time and number of consumers experiencing an outage.
7. Back Office – A suite of applications, supplied by Supplier that are deployed on a standards-based Critical Infrastructure Networking Platform. The applications enable utilities to support multiple advanced grid applications on common infrastructure. The Back Office Systems application suite includes utility applications for advanced grid initiatives as well as network administration software for configuring, upgrading, and managing the advanced utility network.
8. B.E – Best effort
9. BER – Bit Error Rate
10. Border Router – shall mean: A Wi-SUN defined WMN routing deployment-ready platform for interconnecting IP and 6LoWPAN networks. It assumes an Ethernet interface on the IP side and an 802.15.4g interface on the 6LoWPAN side.
11. CCF – is a measurement of space or volume. It represents amount of gas contained in space equal to one hundred cubic feet.
12. CDF – Cumulative Distribution Function; a useful means to quantify statistical network performance metrics. In probability theory and statistics, CDF of a real-valued random variable X, or just distribution function of X, evaluated at x, is the probability that X will take a value less than or equal to x.
13. CSS – Customer Service System
14. CVR - Conservation Voltage Regulation; Systems that facilitate controlled reduction in the voltages received by an energy consumer to reduce energy use, power demand and reactive power demand.
15. CPE – Customer Premise Equipment, used in the context of WiMAX, formally defined as Subscriber Station component of a WiMAX system.
16. CPP – Critical Peak Pricing rate offering
17. CT – instrument Current Transformer
18. DER – Distributed Energy Resources; decentralized energy that is generated or stored by a variety of small, grid-connected devices such as solar, wind or battery.

Essential Definitions

19. DA – Distribution Automation; in this RFP, DA refers to the control aspects of electric and gas field automation, often referred to in the context of SCADA systems.
20. DG – Distributed Generation
21. DMS – Distribution Management Systems; a collection of applications designed to monitor & control the entire distribution network efficiently and reliably
22. DR - Demand Response; (From the Federal Energy Regulatory Commission) is defined as: “Changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized”.
23. EV charging – Electric Vehicle battery charging systems; Systems that are used to charge the batteries of electric vehicles, sourcing energy over the grid.
24. ESB – Enterprise Service Bus
25. FAN – Field Area Network; A collection of (usually) wireless networks, operating over a large geographic area for the purpose of providing data services.
26. FAST AMI – Meter read rates for all meters, excluding the bellwether meters, shall record interval, register and events data every 15 minutes and complete transmission of this recorded data to the Headend, at an interval that does not exceed every 15 minutes.
27. FLISR – Fault Location Isolation and System Restoration combines hardware, software, telecommunications, and grid engineering to decrease the duration and number of customers affected by any specific outage.
28. Field Communication Tool – shall mean: The devices and instruments that are used by AMI field personnel to communicate wirelessly, over the air to gas and electric meters.
29. IEEE – Institute of Electrical and Electronics Engineers; A professional association dedicated to advancing technological innovation and excellence for the benefit of humanity. In Company context, IEEE defines standards for wired and wireless communications.
30. IETF – Stands for Internet Engineering Task Force, a large open international community of network designers, operators, vendors and researchers concerned with the evolution of the internet architecture
31. IHD – In Home Display
32. IP – Internet Protocol address is a numerical label assigned to each device such as computer and printer participating in a network that uses internet protocol communication
33. IPv6 – Internet Protocol version 6 is the most recent version of the internet Protocol (IP), the communication protocol that provides and identification and location system for computers on networks and routes traffic across the internet.
34. IT – Information Technology, the use of systems (especially computers and telecommunications) for storing, retrieving, and sending information.
35. IVVO - Integrated Volt/Var Optimization – Voltage/Voltage-Ampere Reactive Optimization; a suite of modern control technologies that use extensive sensor data, wireless communication links and computational control systems to increase grid visibility and efficiency. Generally, IVVO technology operates by gathering extensive performance metrics on the power lines and equipment through a wireless network then adjusting and optimizing system performance through data analysis and control actions.
36. JTAG – Joint Test Action Group is an electronics industry association for developing a method of verifying designs and testing printed circuit boards after manufacturer.
37. LP – Load Profile Data
38. Momentary interruption - The brief loss of power delivery to one or more customers caused by the opening and closing operation of an interrupting device. NOTE: Two circuit breaker or recloser operations (each operation being an open followed by a close) that briefly interrupt service to one or more customers are defined as two momentary interruptions.
39. Momentary interruption event - An interruption of duration limited to the period required to restore service by an interrupting device. NOTE 1: Such switching operations must be completed within a

Essential Definitions

specified time of five minutes or less. This definition includes all reclosing operations that occur within five minutes of the first interruption. NOTE 2: If a recloser or circuit breaker operates two, three, or four times and then holds (within five minutes of the first operation), those momentary interruptions shall be considered one momentary interruption event.

40. MCF – Is an abbreviation denoting a thousand cubic feet of natural gas
41. MDT –Mobile Data Terminal that could be a notebook/laptop or field tool used by field personnel for completion of assigned work.
42. MTTR – Mean Time to Repair
43. NMS – Network Management Systems; Electronic systems consisting of hardware and software used in the setup, configuration, dimensioning, management and monitoring of data networks.
44. OMS – Outage Management System is a computer system used by operators of electric distribution systems to assist in restoration of power
45. OSI - Open Systems Interconnection model (OSI model) is a conceptual model that characterizes and standardizes the communication functions of a telecommunication or computing system without regard to their underlying internal structure and technology.
46. P2MP – Point to Multipoint Radio Systems; a wireless radio system that generally consists of a single base station that communicates virtually with multiple endpoints.
47. P2P – Point to Point Radio Systems; wireless radio systems that enable wireless communications circuit between two distinct endpoints.
48. PEN – Penetration testing is the practice of testing computer and network systems to find vulnerabilities that could be exploited
49. PHY – in, networking terms, a short form for the component that operates at the physical layer of the OSI layer of the OSI network model.
50. PKI – Public Key Infrastructure is a set of roles, policies, and procedures needed to create manage, distribute, use, store, and revoke digital certificates and manage public key encryption.
51. PPE – Personal protective equipment
52. PTR – Peak Time Rebate rate offering
53. RAM – Random Access Memory
54. RSSI – Received Signal Strength Indicator
55. RTT – Round Trip Time is the length of time it takes for a signal to be sent plus the length of time it takes for an acknowledgment of that signal to be received.
56. SC – Self Contained meters
57. SCADA – Supervisory Control and Data Acquisition; Systems used for remote monitoring and control that operate with data signals over communication channels.
58. SMA – Sub Miniature version A type connector. A semi-precision coaxial RF connector having a 50 Ω impedance.
59. SNR – Signal to Noise Ratio
60. SUN – Smart Utility Network; Networks that are compliant to IEEE 802.15 Smart Utility Networks (SUN) Task Group 4g, consisting of a PHY amendment to 802.15.4, and providing a global standard that facilitates very large scale process control applications such as the utility smart-grid network capable of supporting large, geographically diverse networks with minimal infrastructure, with potentially millions of fixed endpoints.
61. TOU – Time of Use rate offering
62. T-min – minimum time
63. T-Max –maximum time
64. TR – Shall mean: Transformer rated meters
65. VT – Instrument Voltage Transformer
66. WMN –Wireless Mesh Network, refers to any wireless network that operates in a topology in which endpoint mesh nodes cooperate in the distribution of data, relaying information between neighbors. Wi-SUN is an example of a WMN. In the context of Company, WMN shall mean equipment and services that are necessary to implement a SUN compliant network.

Essential Definitions

67. WiMAX CPE or CPE – Customer Premise Equipment, referring to the wireless endpoint equipment on a WiMAX system (although the term may be generalized to other wired or wireless systems). It generally consists of an antenna and transmission line feed system as well as the electronics unit which may be placed inside or exterior to a building (dwelling) or enclosure.
68. Wi-SUN – A WMN Smart Utility Network (SUN) that is compliant to the FAN interoperability profiles set out by the Wi-SUN Alliance. See: https://www.wi-sun.org/
69. WIMAX – Interoperable implementations of the IEEE 802.16 family of wireless-networks standards ratified by the WiMAX Forum.

2 Introduction and Background

The Company has recognized the necessity to establish Advanced Metering Infrastructure (AMI) as a fundamental and essential component to an implementation of Company's Advanced Grid Intelligence and Security (AGIS) initiative.

Company's vision for AMI in the form of a solicitation for proposals from Suppliers for product supply and implementation is contained in this request for proposal (RFP). Suppliers who are adequately qualified are invited to respond to this RFP following the instructions that are provided in this document set.

2.1 Vision and Priorities

The Company AMI strategy provides a coordinated effort for integrating a multitude of business needs and applications into a common platform that can be leveraged enterprise wide by the Company's business units.

AMI data will provide the Company a return on investment and make a positive impact on moments that matter in the customer life cycle. AMI offers enhanced functionalities such as:

- Daily meter reading, enhancing billing and customer management.
- Provides customers with data for enhanced operation of smart appliances and load control.
- Offers the ability to offer variable rate structures. (CPP, PTR, TOU, etc.)
- Offers a cost effective method of providing voltage metrics for IVVO application.
- AMI provides effective premise-specific information to corroborate Momentary Average Interruption Frequency Index (MAIFI)- Regulatory and customer satisfaction driving the need for MAIFI
- Enables premise specific outage management and storm restoration capabilities, even near real-time views of restorations.
- Enables improved power quality event capture. This would enhance response time, proactively resolving distribution problems before they magnify.
- Provides tamper and energy theft detection.
- Enhances demand response programs.
- Enables distributed energy resource (DER) monitoring.
- Enable use of downstream sub-meters for special rates, e.g. - DER and EV charging.
- Enables remote electric service connect/disconnect capabilities, reducing truck rolls.

The Company envisions that its wireless AMI network will consist of clusters of Wi-SUN FAN Profile compliant wireless networks that are founded on the IEEE 802.15.4g and IEEE 802.15.4e standards, providing for wide geographic area network services; all of which are owned and managed by Company internally.

When fully deployed, the network will be fault tolerant in design and topology and be multi-tenant in nature, meaning that multiple applications are expected to share the same communication infrastructure. The multi-tenant nature of the network drives the necessity to implement the network with proven, reliable and efficient end-to-end message priority forwarding protocols.

The Company seeks an AMI solution that is flexible, scalable and backward compatible. Toward this expectation, Company has established internal priorities to implement this AMI RFP focused on the metering components with full expectation of following-on with layered gas and electric SCADA oriented applications.

The Company has a companion WiMAX project underway. In the context of this RFP, WiMAX will be the data backhaul technology of choice for mesh networks. WiMAX will be used at transition points from the mesh network to provide transport services along a path toward Company's core network. WiMAX is a point to multipoint technology providing broadband data services and exceptional quality of service.

Provisioning of WiMAX equipment, implementation services and support services are not in scope for this RFP. Suppliers should carry out designs on the contemplation that WiMAX service will be available in the required coverage areas.

Of significance, the Company places priority emphasis on its cyber and physical security programs. Company seeks to continuously and proactively plan, refine and exercise appropriate levels of attention, action and response to security issues and treats to the intelligent grid. This project will ensure that all AMI components are identified and protected, both for the protection of customers and for the reliable and safe delivery of energy to customers. Additionally, the Company will apply its cyber security program to validate sufficiency of detective controls that are integrated with the Suppliers AMI solution. These activities, and others, help to proactively provide notification of suspicious behavior or anomalous activity.

Finalists to the RFP selection process shall be given access to Company Technology Standards, and Reference Architecture documents. Supplier must confirm that the delivery of the system/product configuration shall conform to these Standards and Reference Architectures. Any exception must be approved by AGIS Lead Enterprise Architect or the Chief Architect.

The Company seeks to adhere to world and industry standards in ways that promote multi-supplier interoperability, industry innovation and operational flexibility and that are exampled in such domains as; Wi-Fi, Ethernet and 3GPP. In this regard the Company is a Wi-SUN Alliance member and supporter and stands behind the basic principles of the organization. This will enable the Company to realize value when installing successively new generation products.

2.2 Project Scope

2.2.1 Understanding the Project Scope Components and Plans

This RFP relates to the supply, design and implementation of AMI for Company, consisting of WMN facilities and meters.

The fundamental operational requirement, detailed herein, will provide the Company with devices and systems that will systematically and programmatically collect electric metering data (consumption, power quality, outages, diagnostic, etc.) and perform advanced functions such remote meter and communication module firmware upgrades, meter programming, and remote electric service connect /disconnect functionality, etc. AMI will provide data that will be used by the advanced distribution management system (ADMS) for applications such as State Estimation, IVVO and FLISR. Mesh network will also enable two-way communication to distribution automation field devices such as cap-bank controls, reclosers, fault locators, etc. These are all essential components of Grid Modernization.

Table 1 – Electric Meter

Alamosa/Salida	25331	1.80%
Boulder	127676	9.06%
Brush/Sterling	12207	0.87%
Denver	223761	15.88%
Evergreen	19031	1.35%
Ft. Collins	31996	2.27%
Greeeley	62426	4.43%
Grand Junction/Rifle	72436	5.14%
Arvada/Brighton	279789	19.85%
Southeast	249491	17.70%
Southwest	266548	18.92%
Silverthorne/Leadville/Vail	38487	2.73%
Pueblo	6	0.00%
totals	**1409185**	**100.00%**

Schedule prioritization is given to the Colorado PSCo service territory with Suppliers expected to provide costs for deploying in other Company service territories as well as provide anticipated volume discount pricing for all hardware and software. The equipment required consists of a collection of WMN control nodes, routing nodes, endpoints and meters, as well as the back office applications that are required to operate and manage the network.

The Scope of Work is AMI centric as is described in Section 3.3.2 “Pricing Methodology” and it includes provisions for implementing network and system related components for electric and gas distribution automation related services.

This RFP is structured as having three distinct components:

1. Equipment Supply,
2. Implementation Services and,
3. Support Services, including Software Licenses and Maintenance

Included in this document is an implementation plan, which sets out the geographic boundaries for the required coverage regions and the estimated endpoint device counts as well as establishing a proposed delivery schedule for implementation.

2.2.2 Implementation Plan and Completion Schedule

As of 2016, there are some 1.4 million electric meters over the PSCo service territory. The full scope of meter counts and percentages is shown in table 2 (below). This table indicates "Blocks" within Company's PSCo service area.

The sequence of installation work relating to the network and meter installation is defined by the Implementation Plan. The implementation plan defines installation and completion dates for network and meters in "Blocks" within the Company service areas. Blocks have been derived from PSCo service center locations and meter "routes" that are historically based on efficient automated meter reading (AMR) drive-by and manual meter reading methods. These methods are now being proposed for replacement.

The implementation plan is based on a business requirement to complete 7%, 57% and 36% meter deployment in 2018, 2019 and 2020 respectively. Nine coverage blocks have been defined. The scheduling requirements for each region are shown in the table [3] below.

Table 2 – Table of Coverage Blocks and Required Completion Dates

Block	Quarter	Divisions	Meter Count	General Location
Block 1	2018 Q4	45% of Denver	100,490	Southwest to southeast of downtown Denver (Southern portion of Denver Metro Branch)
Block 2	2019 Q1	53% of Denver, 28% of North Metro	200,025	Downtown Denver; East, North, and West of Downtown Denver out to DIA (Northern and Eastern portion of Denver Branch, Southern portion of North Metro Branch)
Block 3	2019 Q2	1% of Denver, 27% North Metro, 100% Boulder	204,486	North West of Downtown Denver along 36 up into Boulder, all of Boulder including the canyons (Western portion of North branch, all of Boulder)
Block 4	2019 Q3	45% North Metro, 1% Denver, 30% Southeast	200,133	North and Northeast of downtown Denver, North of Arsenal, South of DIA, along I-225 (North and Eastern portion of North metro branch, eastern portion of Southeast branch, starts south of DIA)
Block 5	2019 Q4	70% of Southeast, 10% of Southwest	199,692	South of Denver Metro, along I-25 (Western portion of Southeast branch and into portion of Southwest branch along I-25)
Block 6	2020 Q1	74% Southwest	198,985	South of Northern Branch, West of I-25 (Western portion of Southwest branch)
Block	2020	16% Southwest, 100% Fort	136,303	North portion of Southwest branch; Fort

7	Q2	Collins, 100% Greeley		Collins and Greeley (Northern most portion of Southwest branch near 6th Avenue, north into Fort Collins branch, and then into Greeley Branch)
Block 8	2020 Q3	100% Sterling, 100% Brush, 100%Evergreen, 100%Leadville, 100% Silverthorne, 100% Vail, 100% Salida, 100% Alamosa, 100% Rifle	109,840	Northeast, Mountains, SLV, Rifle (From Greeley move along I-76 into Brush and then to Sterling. Then go to Evergreen along I-70, on Silverthorne, and then to Vail. Go south to Leadville, Salida, and then Alamosa. Move northwest to Rifle)
Block 9	2020 Q4	100% Grand Junction	57,004	Grand Junction (From Rifle move along I-70 to Grand Junction)
		Total	**1,406,958**	

For purposes of contracting expediency, the proposed dates for network installation and meter exchange completion over the entire Company service territory are shown in Table 3. **Dates shown for operating companies other than PSCo are high level estimates only and subject to revision.**

Table 3 Proposed Completion Dates for AMI Installations

Xcel Energy Operating Company	Estimated Implementation and Completion Dates	Quantity of Electric Meters	Quantity of Gas Meters
Public Service of Colorado (PSCo) Electric	Q4 2018- 2020*	1.4 M	
Public Service of Colorado (PSCo) Gas	TBD		1.4 M
Northern States Power Co – Minnesota (NSPM)	2021 - 2023	1.5 M	550 K
Southwest Public Service (SPS)	2024 - 2025	400 K	0
Northern States Power (NSPW)	2026 - 2027	300 K	150 K

*****Suppliers should base designs and pricing on these dates.

2.2.3 AMI Geographic Coverage Requirements

Coverage requirements are linked to the AMI Completion dates. For PSCo, the schedule relationship between coverage blocks and schedules is delineated in Table 2.

For PSCo, AMI coverage requirements are defined in nine geographic "Blocks". The boundaries of the geographic blocks are defined in the PSCo coverage map Figure [1] and included attachments "AMI Block Deployment with Gas - Only.kmz" and "AMI Deployment Blocks with Gas Areas.pdf"

AMI coverage requirements are provided to Suppliers in the form of spreadsheets. The spreadsheets indicate the location of meter devices provided by geographic coordinates and include specific information concerning the meter device model/type and vintage that is in place as is best known at the time of release of this RFP.

2.2.4 DA Related Geographic Coverage Requirements

Coverage requirements for DA related functions are synchronized to the AMI Completion dates. For PSCo, the schedule relationship between coverage blocks and schedules is delineated in Table 2.

For PSCo, DA coverage requirements are synchronized to the nine geographic "Blocks". The boundaries of the geographic blocks are defined in the PSCo coverage map Figure [1].

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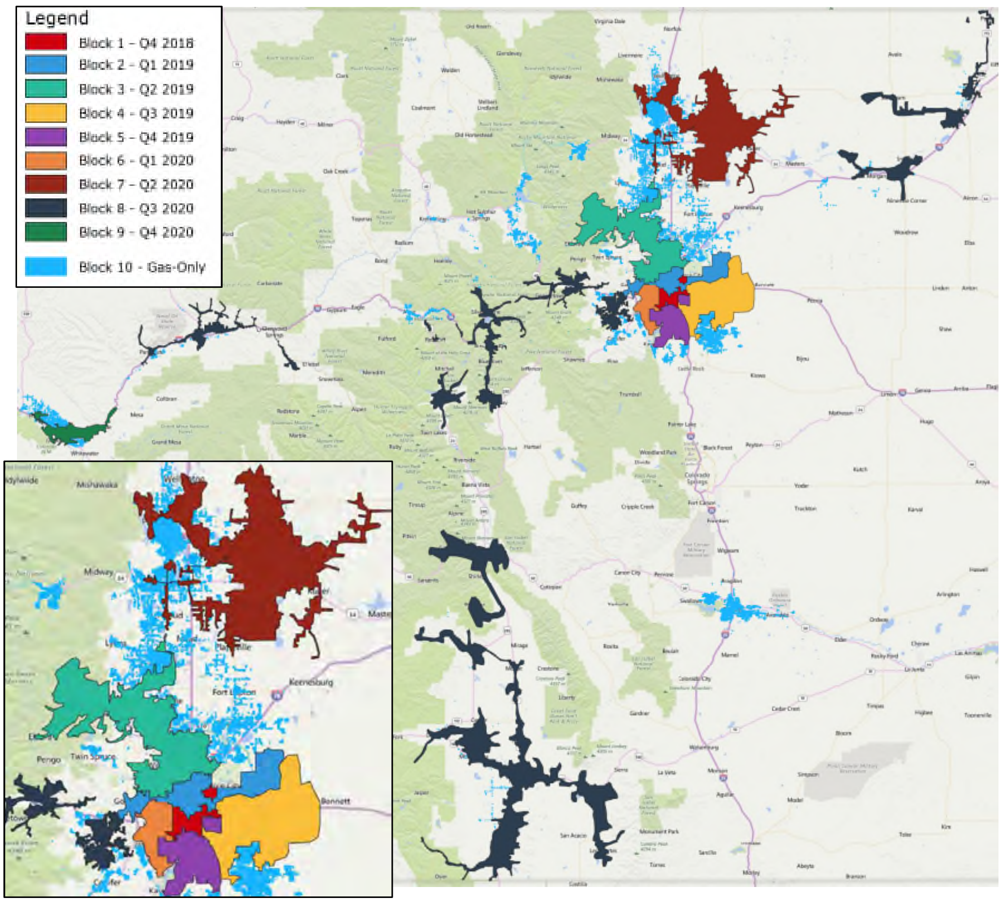
DA endpoint coverage requirements are provided to Suppliers in the form of multi-tab spreadsheets. The spreadsheets indicate the location of meter devices provided by geographic coordinates and include specific information concerning the meter device model/type and vintage that is in place as is best known at the time of release of this RFP.

Figure 1 - PSCo Service Blocks and Required Completion Dates



2.2.5 Equipment Supply, Scope

The Scope of Supply covers the following items;

1. Wireless mesh network equipment
2. Electric residential meters
3. Electric commercial and industrial (C&I) meters
4. Network Management Systems

5. Headend application software equipment for electric and Gas metering, including installation
6. Electric DA infrastructure
7. FAN Lab equipment
8. Meter Shop equipment
9. Field testing equipment
10. Pre-Pay Options
11. Home area network software and hardware
    a. Assume 10% of electric meter customer participation (140,000)
12. Future needs to be priced:
    a. Gas Meter Reading
    b. Electric SCADA endpoint nodes
    c. Gas SCADA endpoint nodes

2.2.6 Supply of Implementation Services – Scope of Supply

Implementation services (per coverage region) include:

1. Project Management
2. AMI Electric and Gas Meter Network Design Services
3. Installation of network equipment and network optimization
4. Inventory, staging, installation, and disposal of electric meters
5. Support installation and configuration of AMI Headend Software
6. Optionally, Installation of Back Office Home Area Network management software components
7. FUTURE
    a. Design and installation of gas metering related infrastructure
    b. Design and installation of electric SCADA infrastructure
    c. Design and installation of gas SCADA endpoint infrastructure

2.2.7 Required Support Services – Scope of Supply

The following support services are required:

1. Training
    a. Meter firmware update – local and remote
    b. Meter programming - local and remote
    c. Headend host application software training – administrative and client and web-based as required
    d. Diagnostics interpretation for troubleshooting on a daily basis
    e. Module programming – Local and remote
2. Product warranties
    a. Meter manufacturers must warranty everything under the meter cover (Metrology, communication module, etc.).
    b. Network warranty
3. Software maintenance support – with detail as to product technical and functional change pricing
4. Hardware and software application maintenance support services.
5. Security Warranties
    a. Security Modules installation, maintenance, and upgrades as required.
    b. Penetration Testing
    c. Scope should include the certificate and key management installation, deployment, management, and retirement
6. Monitoring
    a. Exception handling
    b. Integration of event-based monitoring and escalation process to an Enterprise based monitoring tool

2.3 Essential Requirements

Suppliers participating in this RFP are required to confirm that they are able to supply a system that is functionally in line with Company's vision and in substantial conformance to the essential requirements set out herein. Prior to carrying out a thorough assessment of Supplier responses, Company will evaluate Supplier responses to the Essential Requirements (this Section), and, where Suppliers are able to demonstrate that their solutions are sufficiently in compliance to our vision and requirements, the balance of the RFP response will be comparatively assessed against functional and non-functional requirements; otherwise, it will not be considered.

The Essential Requirements are:

1. The proposed system is capable of gathering and processing AMI related data from an inventory of no less than ten million endpoint devices located in urban, suburban and rural settings of the Company Service territory and meeting the Key Performance Metrics, that is:

    a. At the end of each load profile interval, the system shall be capable of reading residential and C&I electric load profile data and corresponding register data configured for 15 minutes load profile interval recording from all meters except ones configured to support ADMS. Data transmission to the Headend shall be randomized over the next 15 minutes before the next interval close and shall have a reliability of no less than 99.9% on read performance and delivery.

    b. The system shall support the use of no less than 20,000 "bellwether" meters (mix of residential and commercial meters) as distribution sensors for advanced distribution management system (ADMS) in support of applications such as IVVO. 10,000 of these meters shall be assumed to be deployed in the PSCo territory and the rest in the other Company jurisdictions. These meters will be evenly distributed proportionately to electric feeders and shall be configured to record electrical parameters e.g. voltage and power, consumption interval data and register data at a rate of no more than 5 minutes and transmit that data to the Headend at a rate of no more than 5 minutes after close of the interval. The success rate of meter data collection and delivery shall be no less than 99.9%. Refer to attachment "Electric Distribution Points.xlsx" for meter sensor locations.

2. The WMN is Wi-SUN Alliance compliant per Field Area Network Working Group Technical Profile Specification V1.0 (or subsequent revision)). New revisions shall be required to be compatible with the old.

3. The WMN is multi-tenant and fault tolerant in nature, that is: it will consist of clusters of single, shared access, shared media, networks capable of carrying multiple forms of IPv4 and IPv6 traffic for a wide range of applications including but not limited to AMI and SCADA.

4. AMI Suppliers shall provide proof of support for three (3) out of four (4) major meter manufacturers with whom Company has business relationships; these meter manufacturers include Elster, Itron, Landis+Gyr and Aclara. If AMI Supplier also manufacturers meters, then their brand of meters shall constitute one (1) of the three (3) meter Suppliers required. If all proposed three meter manufactures are not presently supported, AMI Suppliers shall provide dates that meter support will be commercially available. Meter support of all meter forms from three (3) meter manufacturers shall be required within 10 months following contract signing and all meter forms from the three suppliers shall be provided to Company for first article testing (FAT).

    Full feature support for the following meters shall be required for all three (3) Suppliers:

    a. Class 20 forms 3S, 4S, 5S, 6S, 9S, 35S , 36S and 45S
    b. Class 200 Forms 1S, 2S, 12S and 16S

c. Class 320 Forms 2S, 12S and 16S

5. The AMI system includes full-meter programming, metrology firmware update and communication module firmware update for (3) of the following meters supported by the Suppliers as stated in requirement 4 above.
   a. Itron(Centron II, Centron II Poly-phase)
   b. Landis+Gyr (Focus AXD, Focus WR AXD, S4e)
   c. Elster (A3T, A3RAL, A3RALNQ,etc)
   d. Aclara (I-210, KV2c)

6. Suppliers are required to provide AMI gas modules that retrofit to all of Company's meter population. Xcel's meter population list is attached (Final – PSCo Meters.zip, Final – NSPM Meters.zip, Final – NSPW Meters.zip)

7. The WMN shall include and operate under IETF and Wi-SUN standards for routing and multi-level priority marking, classifying, queuing and forwarding of data packets.

8. The manufacturer will be capable of delivering complete systems, conforming to the essential requirements following the timelines set out herein.

9. Suppliers are required to adhere to the Companies main cyber security principles, that is:
   a. Utilize Cyber Security Best Practices (e.g. NIST SP800-53, NISTIR 7628, NIST CSF)
   b. Defense-in-depth: Ensures there are multiple layers of protection and detection defined.
   c. Zero Trust: Creates isolation points within the information network so only specific hosts are able to communicate with other specific hosts.
   d. Tightly-Controlled Access: Ensures only necessary people and systems are able to access devices or software.
   e. Least Privilege: Only necessary individuals and services are allowed to interact with devices.
   f. Least Functionality: Only necessary ports and services are open and running on the systems and devices.

2.4 Security Requirements

2.4.1 Overview

1. As the Company adds intelligence to the electric grid, each part of the grid must be evaluated for cyber security risk. The risks must be mitigated to ensure the reliable delivery of electricity to our customers. The Company has developed principles, strategies, and requirements to assist in identifying and mitigating the risks.

2. Suppliers are required to comply with all of the Principles, Strategies and Requirements outlined in Sections 2.4.2, 2.4.3 and 2.4.4.

2.4.2 Principles

1. Utilize Cyber Security Best Practices (e.g. NIST SP800-53, NISTIR 7628, and NIST CSF).
2. Defense-in-Depth Posture: Ensures there are multiple layers of protection and detection defined.
3. Zero-Trust Networking: Creates isolation points within the information network so only specific hosts are able to communicate with other specific hosts.
4. Tightly-Controlled Access: Ensures only necessary people and systems are able to access devices or software.
5. Least Privilege: Only necessary individuals and services are allowed to interact with devices.

6. Least Functionality: Only necessary ports and services are open and running on the systems and devices.

2.4.3 Strategies

1. Conforms to industry standards and best practices as pertains to meter technology.
2. Support and utilize secure network communication protocols where practical (e.g. HTTPS, SFTP, SSH, SSL, TLS, etc.)
3. Leverages strong authentication and authorization model (role-based access to individual meters).
4. Support a “deny-by-default” approach to AMI component configuration
5. No reliance on non-secure protocols/ports when possible (e.g., telnet).
6. Disable all unnecessary and unused protocols/ports.
7. Support and integrate with centralized system configuration, change management and monitoring systems
8. Security event logging capabilities should be utilized and regularly reviewed.
9. Unauthorized access attempts shall be logged with alerts presented to the appropriate parties.

2.4.4 Requirements

1. The AMI Headend application integration interfaces shall allow the security administrator to generate security reports based on the integration interface’s logs.
2. If Supplier has access to any Company or client confidential information, please describe how confidentiality is going to be maintained, including how information is retained and/or disposed of at designated times.
3. The corporate software maintenance process shall be followed for upgrades and patches.
4. Vulnerability scans are to be performed for equipment or product before it is put into both test and production.
5. Product shall not use unsupported open source code or operating systems.
6. Product shall have application security testing performed by Supplier and the results shall be shared with Company.
7. AMI Supplier shall follow best practices in their coding by utilizing secure application development methodologies such as OWASP.
8. All product testing shall be performed in non-production environments.
9. All security logs shall be captured by a centralized logging device, such as Security Incident and Event Management (SIEM).
10. Data encryption shall be utilized for both data-at-rest and data-in-motion.
11. Encryption algorithms shall be of sufficient strength with equivalency of AES-128.
12. Multi-factor authentication shall be utilized.
13. AMI Headend user access shall utilize role-based security, enabling access to be assigned by , for example, functionality, geographic area(s), asset grouping, and business areas.
14. Active Directory shall be used for user and service authentication.
15. Credentials are required to be stored in encrypted form.
16. Secure messaging shall be utilized whenever technically feasible such as SFTP.
17. If mobile technology is available, the application shall be compatible with Mobile Device Management Systems.
18. Appropriate firewall rules shall be used.
19. Intrusion prevention technology shall be utilized.
20. Only secure TCP/IP protocols shall be utilized.
21. Least functionality principles shall be practiced.
22. Least Privilege principles shall be practiced.
23. Defense-in-depth posture shall be practiced.
24. Zero-Trust Networking shall be practiced.
25. Tightly-controlled access shall be practiced across all network layers.

26. The AMI Headend shall support 8-character password with complexity (upper and lower case alpha, numeric, special characters).
27. The AMI Headend application shall not need to store Personal Identifiable Information (PII), but if it does, the application shall ensure the security and privacy of such information.
28. A Supplier shall notify Company immediately in writing and electronically when a security vulnerability is identified.
29. A patch shall be released to resolve a firmware or security issue within 30 days of identification of an issue.

3 General Provisions

3.1 Invitation to Bid

This RFP invites Suppliers to submit Proposals setting forth all terms, including pricing, for the provision to Company of the equipment and services listed herein at all of the required locations set out herein.

Consults will also be asked to redline a base agreement, provide insurance documentation, Security questionnaire as well as complete a subcontracting diversity form.

Suppliers who are participating in this RFP are required to confirm that they are able to supply a system that is functionally in-line with Company's vision and in substantial conformance to the essential requirements set out herein. Prior to carrying out a thorough assessment of Supplier responses, Company will evaluate Supplier responses to the Essential Requirements (Section 2.3) , and where Suppliers are able to demonstrate that Supplier solutions are sufficiently in compliance to Company vision and requirements, the balance of the RFP response will be comparatively assessed against functional and technical requirements of the RFP.

In order to propose the provision of the Equipment and/or Services as specified in this RFP, the Supplier, in addition to any other requirements in this RFP, shall:

1. have signed the pre-requisite Confidentiality and Non-disclosure Agreement with Company;
2. have significant, demonstrable experience providing the same or similar AMI/DA and Networking Equipment and Services as those identified herein;
3. be able to provide the Services and/or Equipment at all of the required locations set out herein, either by itself or through a subsidiary, affiliate, parent company or its partner, all of whom are otherwise qualified as defined in this RFP;
4. Demonstrate that its financial situation is sound (refer to Section 4.2 – Corporate Profile).
5. Connect the company with other customers that have deployed similar systems being proposed.

In order to propose the provision of any components of this RFP, the Suppliers must comply with the requirements of this RFP including all sections.

3.2 Critical Dates in the RFP Process

Table 4 - Critical dates for RFP processing

No	Scheduled Item	Required Schedule
1	Supplier Presentations	23-27 May 2016
2	RFP Released to Suppliers (RFP OPEN)	25 July 2016
3	Questions from Suppliers Closing Date	22 August 2016
4	Supplier Demonstrations	18 July to 14 October 2016
5	RFP Responses Delivered to Company (RFP CLOSE)	29 Aug 2016
6	Recommended Supplier of choice Identified	4 November 2016

3.3 Instructions to Suppliers

The following instructions are additional to those provided in the attached document titled: Instruction to Bidders. Instruction to Bidders can be downloaded from the Company Emptoris website.

3.3.1 Company Emptoris Response Procedures

1. Suppliers are required to respond to this RFP using the Company Emptoris Secure Internet Sourcing System. Follow the instructions set out herein:
   a. Logon to Xcelenergy.esourcing.emptoris.com

b. Enter your user name in the Name field.
c. Enter your password in the Password field.
d. Click the Login button.
e. From the main menu select RFx(s) > Manage RFx(s).
f. Locate the RFx Name in the list of RFx(s).
g. Click on the RFx Name link to view the RFx.

2. Note: Once you have reviewed the RFP material, please click the Green "Accept" button as your intention to bid or the Red "Decline" button as an indication that you will not be participating.

3. Be sure to answer all questionnaires and questions.

4. Pricing shall be submitted via the "Single Bid" tab or "Multibid" Tab. Please adhere to the format, no other formats will be accepted unless otherwise approved by Company.

5. Suppliers are required to address the following documents which are attached to the event. Please download these, and upon review, upload your return documents with ***Original document name-Supplier name*** included in the file name so submissions may be deciphered. Documents include:

   a. This RFP [Advanced Metering Infrastructure Request for Proposal for Company]
   b. Instructions to Bidders
   c. Sample No Opportunity for SUB Letter
   d. Sub-Contracting Plan
   e. Sample Insurance Certificate
   f. General Conditions Major Supply Agreement – Any redlines should be documented on the original document and returned as an attachment. Note that any exceptions will be weighted and may preclude Supplier from further engagement in the sourcing process.*
   g. Xcel Energy AMI RFP Pricing Template v4
   h. Safety Program Requirements

6. Suppliers are required to provide a comprehensive written response to this RFP providing specifications, confirmations and descriptions in response to the RFP specifications and queries.

7. Suppliers shall submit responses in a form that linked to the RFP numbering and therefore appropriately accessible to the response reviewers. Suppliers are required to respond to each and every numbered point in this RFP by providing a short form summary of their offering on a line by line basis:
   a. Supplier's responses to this RFP shall be clearly titled and numbered.
   b. Suppliers shall indicate whether they "comply" or "do not comply" with each numbered section and point. In the case of "non-compliance", append a clear description of how the supplier's solution meets Company's requirements.
   c. Requirements or statements are numbered as simple list items such as 1,2,3, Suppliers should interpret numbers to be an extension of the higher level numbering scheme. Example: in item number 5a of this section (3.3.1) should be identified as "3.3.1.5.a" in Supplier responses.
   d. Supporting documentation shall be cross-referenced, clearly marked and attached as appendices.
   e. Once complete, Suppliers are required to submit their responses through Company Emptoris Secure Internet Sourcing System only. The attachment will use the following naming convention: Xcel Energy AMI RFP Responses-supplier name.

3.3.2 Pricing Methodology

1. Pricing is structured into two tiers, namely: AMI and DA.

a. AMI (Advanced Metering Infrastructure) refers to hardware, software and services that are associated with electric and gas metering.
b. DA (Distribution Automation) refers to systems that are used for monitoring and control of gas and electric systems; generally, this includes all forms of SCADA.

2. Pricing is required to be tendered by Suppliers in two ways; namely;
   a. Firm Fixed pricing for AMI and DA functionality that is specified over a defined Coverage block(s). Suppliers are required to tender a price for each block for each of AMI and DA requirements.
   b. Variable pricing for equipment and services to the extent of all Company service territory.

3. Suppliers are required to tender pricing in itemized form through completion of the pricing template attached here as: Xcel Energy AMI RFP pricing Template v4.0.xlsx. Supplier must respond to all sections of the pricing Template including the grouped items under the (+) columns.

4. Following a period of assessment and negotiation, Company expects to:
   a. Form a Master Services Agreement (MSA) and companion Statement of Work (SoW) for one or more of the Initial Service Blocks
   b. Consider purchases beyond the Initial Coverage Blocks based on the pricing and pricing formulas provided in the response to this RFP or as subsequently negotiated.

3.3.3 Pricing Modules

The following pricing is required to be tendered, in the form of itemized tables on the attached spreadsheet name: Xcel Energy AMI RFP pricing Template v4.0.xlsx.

Refer to the “Xcel Energy AMI RFP pricing Template v4.0.xlsx” where Suppliers are required to enter their pricing information.

Table 5 -- Pricing Modules

No/ Tab	Name	Item	Resources
1	Baseline AMI PSCo Coverage Block 1-9 and Block 10	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (Q42018 - 2020). Pricing must be itemized per block and per design, supply, installation and services components. Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where Company offers electric and gas service and for areas that offer gas service exclusively. Gas components include module installation.	Per requirements set out herein: • Coverage area “blocks” defined in Figure 1. • AMI requirements in Section: 5. • Network requirement in Section 6. • Baseline read/transmission rates are defined in Section 5.3.1 • Services requirements in Section 7. • Electric AMI Meter locations and types in attachments: <Final – PSCo Meters.zip> and, < Xcel Energy AMI RFP pricing Template v4.xlsx> • Gas Meter locations and types in attachments: <Final – PSCo Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
2	Fast Transmission AMI PSCo Coverage Block 1-9 and Block 10	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (Q42018 - 2020). Pricing must be itemized per block and per design, supply, installation and services components.	Per requirements set out herein: • Coverage area “blocks” defined in Figure 1. AMI requirements in Section: 5. • Network requirement in Section 6. • Fast read/transmission rates are defined in Section 5.3.2 • Services requirements in Section 7. • Electric AMI Meter locations and types in attachments:

		Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where Company offers electric and gas service and for areas that offer gas service exclusively. Costs of gas meter reading modules, design and supply must be separately identified. Gas components include installation of modules.	<Final – PSCo Meters.zip> and, < Xcel Energy AMI RFP pricing Template v4.xlsx > • Gas Meter locations and types in attachments: <Final – PSCo Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
3	Five Minute Read rate Intervals PSCo Coverage Block 1-9 and Block 10	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (Q42018 - 2020). Pricing must be itemized per block and per design, supply, installation and services components. Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where Company offers electric and gas service and for areas that offer gas service exclusively. Costs of gas meter reading modules, design and supply must be separately identified. Gas components include installation of modules.	Per requirements set out herein: • Coverage area "blocks" defined in Figure 1. • AMI requirements in Section: 5. • Network requirement in Section 6. • Five Minute Interval Read Rates are defined in Section 5.3.3 • Services requirements in Section 7. • Electric AMI Meter locations and types in attachments: <Final – PSCo Meters.zip> and, < Xcel Energy AMI RFP pricing Template v4.xlsx> • Gas Meter locations and types in attachments: <Final – PSCo Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
4	AMI for SPS	Fixed pricing for all AMI electric meter and network equipment, network design and installation, based on a 2 year deployment (2024-2025). Pricing must be itemized per design, supply, installation and services components.	Per requirements set out herein: • AMI requirements in Section: 5. • Network requirement in Section 6. • Baseline read/transmission rates are defined in Section 5.3.1 • Services requirements in Section 7. • Meter locations and types in attachment <Final – SPS Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
5	AMI for NSPM	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 3 year deployment (2021-2023). Pricing must be itemized per network design, supply, installation and services components. Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where Company offers electric and gas service and for areas that offer gas service exclusively. Gas components include installation of modules.	Per requirements set out herein: • AMI requirements in Section: 5. • Network requirement in Section 6. • Baseline read/transmission rates are defined in Section 5.3.1 • Services requirements in Section 7. • Meter locations and types in attachment <Final – NSPM Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx > • Gas Meter locations and types in attachment: <Final – NSPM Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx >
6	AMI for NSPW	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (2026-2027). Pricing must be itemized per design, supply, installation and services components. Costs of gas meter reading modules, network design and supply must be separately identified for both service territories where	Per requirements set out herein: • AMI requirements in Section: 5. • Network requirement in Section 6. • Baseline read/transmission rates are defined in Section 5.3.1 • Services requirements in Section 7. • Meter locations and types in attachment <Final – NSPW Meters.zip> and <Xcel Energy AMI RFP pricing Template v4.xlsx Tab> • Gas Meter locations and types in attachment: <Final – NSPW Meters.zip> and

		Company offers electric and gas service and for areas that offer gas service exclusively. Gas components include installation of modules.	<Xcel Energy AMI RFP pricing Template v4.xlsx >
7	DA for PSCo Blocks 1-9	Fixed pricing for all AMI meter and network equipment, network design and installation, based on a 2 year deployment (Q42018 - 2020). Pricing must be itemized per block and per design, supply, installation and services components.	Per requirements set out herein: • Coverage area "blocks" defined in Figure 1. • Technical requirements in Section 6. • Services requirements in Section 7. • DA locations in attachment <Electric Distribution Points.xlsx> and <Gas Distribution Points>
8	DA for SPS	Fixed pricing for all equipment, network design and installation pricing for DA services based on 2 year deployment (2024-2025). Pricing must be itemized per design, supply, installation and services components.	Per requirements set out herein: • Technical requirements in Section: 6 • Services requirements in Section: 7 • DA locations in attachment Electric Distribution Points.xlsx
9	DA for NSPM	Fixed pricing for all equipment, network design and installation pricing for DA services based on a 3 year deployment (2021-2023). Pricing must be itemized per design, supply, installation and services components.	Per requirements set out herein: • Technical requirements in Section: 6 • Services requirements in Section: 7 • DA locations in attachment <Electric Distribution Points.xlsx> and <Gas Distribution Points>
10	DA for NSPW	Fixed pricing for all equipment, network design and installation pricing for DA services based on a 2 year deployment (2026-2027). Pricing must be itemized per design, supply, installation and services components.	Per requirements set out herein: • Technical requirements in Section: 6 • Services requirements in Section: 7 • DA locations in attachment <Electric Distribution Points.xlsx> and <Gas Distribution Points>
11	Replace form 2s meters with form 12s meters	Carry out pricing in the exact same manner as Table 5 item 1 but replace all form 2s meters with form 12s meters.	All Requirement are the same as Table 5 Item No. 1 with exception of noted meter form change
12	Meter Shop	Price proposal to design, set-up and configure a meter shop in Denver, Co	Per requirements set out in Section 6.6 herein.
13	Phase Identification	Price proposal for additional components that are required to implement systems capable of identifying phase	Per requirements set out in Section 5.7 herein.
14	Headend Application	Fixed price for redundant server Headend Application for AMI Control	Per requirements set out herein: • Technical and operational requirements in Section 5.5 and 5.6
15	Network Management Systems	Redundant Network Management System	Per requirements set out herein: • Technical and operational requirements in Section 6.1.1
16	Incremental Headend	Incremental license costs to AMI Headend components (priced per 1000, meters)	Per requirements set out herein: • Technical and operational requirements in Section 5.5 and 5.6
17	Incremental NMS	Incremental license costs to NMS components (priced per 100 network nodes)	Per requirements set out herein: • Technical and operational requirements in Section 6.1.1
18	Itron 100g support	Meter Reading and Network support for up to 500,000 Itron 100G ERT modules	Per requirements set out herein: • Technical and operational requirements in Section 5.10 herein • Location of 100G ERT modules: <Final- PSCo ERT Modules.zip>
19	T&M	Roles and Responsibility rate card indicating hourly rate as well as discount provided to Company	Volume Tier Rates
20	HAN	Optional Pricing for all required equipment and services required to establish a HAN offering	Per requirements set out herein in Section 5.8
21	All Goods	Price for warranty covering all goods and	Per requirements set out herein in Section 8.1

General Provisions

	Warranty	services. Covers equipment and services as defined in "blocks and/or regions and handles meters separately.	
22	Blank	Intentionally left blank	• Intentionally left blank
23	Support Services	Support Services, includes field maintenance, online support services, software support agreements, etc.	Per requirements set out herein in Section 8.2
24	Software Support Agreements	Price for renewable Software Support Agreement	Per requirements set out herein in Section 8.1.2
25	Field Service Equipment	Pricing for equipment used by Company field personnel	Per requirements set out herein in Section 6.7
26	WiMAX Gateway Requirements	Pricing for interface enclosures – between Wi-SUN border router and WiMAX CPE	Per requirements set out herein in Section 6.2
27	FAN Lab Equipment	Itemized pricing for all equipment necessary to equip FAN lab in Denver, Co	Per requirements set out in Section 6.5.

1. AMI systems are considered to be baseline. This means:

    a. In areas where the Company services both electric and gas the network shall be designed to support both services.
    b. AMI pricing includes all back office and field equipment, systems, network design installation, testing, performance verification, warranty, training, etc.
    c. For purposes of pricing all AMI systems are assumed to be interconnected to the Xcel Core network by way of WiMAX networking.
    d. All AMI systems shall be designed and included in implementations, without compromise, on the expectation and principle that the DA tier will be added. The DA tier will be added either concurrently or incrementally at a later date.
    e. Where equipment and or services are required at AMI system installation time to meet longer term DA requirements but is superfluous to immediate AMI needs, it shall be included in the AMI design and so priced. Suppliers are required to identify and separately price any and all equipment fitting this DA requirement.
    f. Where equipment and or services are required for DA functionality and are not necessary to purchase, design, integrate or install at AMI installation time, such items shall not be included in AMI pricing but rather included in the DA system pricing.

2. DA systems are considered to be supplemental to AMI systems. This means:

    a. DA pricing includes all back office and field equipment, systems, installation, testing, performance verification, warranty, training, etc., that is required so as to meet the DA functional requirements and that are supplemental to AMI.
    b. For purposes of pricing all DA systems are assumed to be interconnected to the Xcel Core network by way of WiMAX networking and using AMI related interface equipment such as but not limited to border routers.
    c. Unless specifically called out in this RFP, all DA systems shall be designed on the principle that the AMI tier will be in place prior to implementing DA services.

3. There are 10 coverage blocks defined by Company for the PSCo region. Each coverage block defines an area to be served and a delivery schedule. Block 10 represents service territory in which Company offers only gas services.

4. For coverage blocks 1-10 PSCo, Company has provided:

a. A table showing the specific location of every known electric meter and a description of the existing installed meter device.
b. A table showing the specific location of every known gas meter and a description of the existing installed meter device.
c. A table indicating the specific location of every known metering points and control endpoints for electric applications. In some cases, the tables contain randomized data designed to be representative of the required installed locations.
d. A table showing the specific location of every known control endpoints for gas applications

5. For all other operating companies in Company Service territory, Company has provided:

    a. A table indicating the location of electric meter deployments and a description of the existing installed meter devices
    b. A table indicating the density of gas meter deployments and a description of the existing installed meter devices.
    c. A table indicating the density of control endpoints for electric applications over the coverage areas
    d. A table indicating the density of control endpoints for gas applications over the coverage areas

3.3.4 Security Related Responses

Security responses are considered to be highly confidential in nature and will be handled on a "need to know" basis during the RFP evaluation process. Suppliers shall:

1. Address all questions associated with AMI Security in a manner that respects the requirements for confidentiality. Questions related to Security shall be isolated from other non-security related questions and submitted to Company by way of Emptoris (See Item 3.3.4d for addressing methodology)
2. In preparing a response to this RFP, isolate and separate all RFP items that are associated with Security and respond in a single, separately labeled package and submit way of Emptoris (See Item 3.3.4d for addressing methodology)
3. In all cases, Supplier responses shall reference the RFP question and number, followed by Supplier query or response.
4. Suppliers are required to submit their Security related responses through Company Emptoris Secure Internet Sourcing System only. The attachment will use the following naming convention: Xcel Energy AMI Security Responses-Supplier name.

3.3.5 Managing Questions and Inter-Company Communications

1. Prior to submitting questions, Suppliers are requested to review the full RFP, formulate your questions and submit them via the Emptoris portal in compliance to the schedule. Company will then respond to your questions in compliance to the schedule.
2. Questions are required to be submitted in batched written format. Please batch your questions using five segments (1) AMI, (2) Meters ,(3) Mesh networking,(4) DA, (5) HAN
3. All questions and answers will be distributed equally to all participating Suppliers for transparency purposes.
4. Suppliers are directed to communicate all questions via Company Sourcing: Contact Dan Pendar (612-330-6521) or Barry Brooks (612-321-3154).

3.3.6 Evaluation Procedures for the Proposals

Where Supplier Responses meet evaluation conditions that are set out in in the "Essential Requirements - Section 2.3", herein, the Supplier's response will be evaluated critically for its merits, and considering the following:

1. Demonstration Performance Evaluations
2. RFP Proposal Responses including ability to meet industry acceptable standards
3. RFP Pricing
4. Acceptability toward synchronization to Company goals and vision
5. Ability to meet execution timing
6. Ability to meet Company current and future needs

3.3.7 Contact Information

Suppliers are required to include in their response, a table indicating the parties with whom Company may communicate with regard to the content of individual Sections. The following table is a reference template:

Table 6 - Contact Information – Example Supplier's Fill-in Table

RFP Section	Business Area	Team Member	Lead or SME	Email	Telephone
	Business terms and Conditions				
	AMI Systems				
	Networking and DA Systems				
	Mesh networking				
	Warranties				
	Support Services				
	Installation Services				

4 Business Terms and Conditions

4.1 Additional Business Terms and Conditions/Pricing

In addition to any Business related Terms and Conditions and other legal/business matters outlined in attachments to this RFP, the following conditions are appended:

1. Where Suppliers offer 3rd party electric meter components as part of any whole meter related offering, such offerings shall be put forward in a form that includes a pass-through agreement with the source manufacturer which is inclusive of no less than the wholly integrated and functional equipment, long term support services and warranties.
2. Suppliers are requested to outline the value added services (above and beyond those outlined within this RFP), that your organization will bring to Company for this project at no additional cost to Xcel.
3. Suppliers are requested to outline the cost take out guarantee which your company will provide to Company over the life of this Agreement. Please provide examples and formula for tracking.
4. Suppliers are required to review and accept the General Conditions for Major Supply Agreement document. Supplier may provide exceptions (redlines) on the document and submit, as an attachment, back to Company for review. Note that exceptions will be weighted and may preclude your company from further engagement in the sourcing process.
5. Please provide a high-level overview of what the market is currently tracking as success metrics utilized to gauge the success of deployment projects of this scope (please include economic and technical considerations). You will be expected to provide “success tracking” dashboards for reporting purposes if awarded this business.
6. Suppliers are required to inform Company in writing of any foreign nationals including subcontractors who will work-on or provide advice concerning the contents of this RFP/project and its outcomes.
7. Company shall require advanced engineering change notification for all hardware and firmware changes. Changes should include risk/impact assessment.
8. Company shall require advanced notification of all reliability/failure causes and effects that have become known to the manufacturer.

4.2 Executive Level Support

Suppliers are required to provide a Statement indicating the level of Corporate Commitment to which Supplier is undertaking. Indicate no less than:

1. The Statement of Commitment to Company articulating the key elements where executive commitment brings value to Company’s Projects.
2. Names and positions of executives who represent the Commitment.
3. The manner in which Executive Level Support is applied to the Supplier’s customers, specifically to Company and to the Supplier’s internal resources.
4. The manner in which Executive Level Support is executed where it relates to the Supplier’s own hierarchy internal resources.

4.3 Required Corporate Information / Supplier Profile

Suppliers are required to submit Corporate Profile related information as follows:

a. Supplier legal name.
b. Supplier Contacts, Phone, Fax, Email, Web Sites
c. Postal mail address of business headquarters and field offices
d. Supplier names, including international, of organizations that sell and or resell the Supplier equipment and services.

e. Dunn and Bradstreet#, ABA#
f. W9 detail, Invoice Remittance and Banking Information
g. Diversity Certification
h. Corporate history since inception.
i. Corporate Mandate; including:
    i. Mission,
    ii. Business sectors in which the Corporation is operating in; (water, gas, electric, smart cities, etc.)
    iii. Percentage of revenue generated by electric/gas utility markets in past 3 years
j. Description of Projects taken on in last 10 years that are similar, including
    I. Exact system installation and generation as proposed for this RFP
    II. US Dollar value of the project
    III. Nature of the project (metering, DA, smart Cities, etc.)
    IV. Customer reference; names, email address and phone number
    V. How the project scope and scale compare to Company's

4.4 Obligations of Company

4.4.1 General Obligations:

Company will:

1. Be reasonably available for questions and meetings in a timely manner during normal business hours.
2. Provide contact list, including a Project Manager Single Point of Contact, of the Company managed project resources and stakeholders.
3. Coordinate and provide required security clearances and/or escorts to access the site and facilities for completion of the services described in this RFP within Company's standard security response times. Unescorted Access security clearance times may average between 2-4 weeks and Supplier shall plan accordingly.
4. Execute according to the agreed upon plans at hand-off/interface points, including the completion of material responsibilities assigned to Company in any SoW that results from this RFP.
5. Assist the Supplier in discussions with any Third Party that Company requires Supplier to manage within the scope of the project, and authorize the Supplier to manage and direct such Third Parties on Company's behalf, if necessary.
6. Use reasonable efforts to secure the cooperation of all and any necessary license rights from Company's Third Party Suppliers as required for Supplier's performance of the services, except for any Third Party cooperation or licenses for which the Supplier is responsible or is required to obtain under Applicable Law.
7. Reserve the right to witness and inspect the project work at any time.

4.4.2 Obligations Regarding Project Management:

Company will:

a. Designate a Project Manager
b. Provide the high level project schedule.
c. Provide site documentation, drawings, and master records (if available).
d. Assist the Supplier in the creation, distribution, and adherence of an overall project schedule
e. Take reasonable steps to execute and deliver on required tasks in a timely manner.

4.4.3 Obligations Regarding Field Area Network design

Company will:

1. Provide the specific placement criteria and installation techniques acceptable to Company for the installation of mesh network equipment on Company facilities.
2. Conduct site surveys to validate the initial field network design. Review the site survey and recommended installation locations and propose changes to these locations if necessary.
3. Secure and pay for all internal and external approvals, improvements, modifications, for attachment of network equipment, including local construction permits, licenses, or other fees. This step must be completed prior to AMI deployment.
4. Determine the method of power connection (direct line connect or photo cell adaptor on a streetlight arm) for network equipment at any given location.
5. If necessary, and upon mutual agreement of the Parties, install additional poles, or provide alternate installation methods, to satisfy the Network Design requirements.
6. Upon Company's acceptance of Supplier's Design, Company will provide backhaul capabilities consistent with the Network Design. Company intends to provide a private WiMAX network as the primary backhaul communication technology. The Supplier will be carrying out designs based on interconnecting Wi-SUN border routers to WiMAX CPE and directly to layer 3 switches that are located at network access points on the Xcel fiber network, typically at substation locations.
7. Company may elect, in certain circumstances, to use a Third Party WAN provider(s) (e.g., cellular operators) to provide backhaul capabilities. If Company elects to do so, Company shall obtain the services of the Third Party WAN provider, provide coverage maps to Supplier for use during the design of the field network, and facilitate communications between Supplier and the Third Party WAN provider regarding operational issues.
8. In gas only areas, Company shall handle third party agreements for required attachment facilities.

4.4.4 Obligations Concerning AMI Meters and Network Deployment

Company will:

1. Use an electronic work order system, or functional equivalent that collects barcode data and GPS coordinates for each location where the meters and mesh network transition equipment is installed.
2. Following training by Supplier, install and perform all field investigations and remediation of network field equipment. Supplier shall take responsibility for failures beyond the Supplier's stated acceptable limits as stipulated in the subsequent contract.
3. Following training by Supplier, perform all field investigations and remediation of AMI meters.
4. Complete all tasks necessary to inventory, warehouse, and stage for installation all network equipment (excluding AMI meters and associated tools and materials covered under Section 7.5 of this RFP), provided that Supplier adheres to all shipping requirements specified by Company, including but not limited to, shipping to a designated recipient.
5. Compile as-built data for network equipment that includes pertinent information about the location of each device, including but not limited to GPS coordinates, AC power source, device height, inventory control information for the object to which the access point or relay will be attached (e.g., inventory control tag on a utility pole, transformer tag on a pad-mount transformer, asset tag for a street light or pole belonging to an entity other than Company, etc.), and any other relevant site-specific information. GPS Latitude and Longitude coordinates must not be truncated to fewer than 5 places after the decimal point; for example 37.46668 rather than 37.466.
6. Perform troubleshooting of installed network equipment and correct any installation errors caused by Company prior to completion of formal acceptance testing.
7. If a Third Party installer is utilized, Company shall provide specifications for attaching network equipment prior to the scheduled date for installation.
8. Provide any 'make-ready' components and consumable commodity supplies needed for completion of the mutually approved installation (e.g., transformers, arms, miscellaneous wire and raceways, wiring connectors for secondary voltage connections on utility poles, and through

bolts, lag screws, and/or stainless steel banding to mount RF pole-top devices to wood or metal poles)

9. Complete all tasks necessary to order, inventory and warehouse Equipment needed to install the network equipment (excluding AMI meters).

4.4.5 Obligations Concerning Back Office setup

Where it is determined to be necessary for support and maintenance requirements, establish a B2B VPN connection from the Company back office to the Supplier Back Office Systems Environment. Each Party shall pay for its cost to set up its end of the B2B VPN connection. The recommended approach typically is for the Supplier to assign and provide a secure DMZ where the product upgrades/patches etc. are downloaded and applied

4.5 Supplier Obligations

1. Notwithstanding the details of Supplier obligations stated herein and the foretasted obligations of Company, Supplier shall state the obligations that are necessary for Company to accept, that are necessary for Supplier to fulfil its obligations under this RFP. The Statement of Company Obligations shall:
   a. Be in the form of list of resources required by role and responsibilities
   b. Indicate the timeline that is required for the requirement to be completed by Company
   c. Include any equipment to be supplied by Company or by any 3rd party .
   d. Include any services to be supplied by Company or by any 3rd party .
   e. Include any additional commitments required from Company to deliver
2. All documentation supplied or submitted to Company shall be in the form of MS Office 2010 formats unless otherwise approved by Company.

4.6 Demonstrations Required for Company AMI RFP

4.6.1 Demonstration Conditions

Company requires that all Suppliers wishing to participate in the AMI RFP process- carry out a hosted demonstration of the proposed system. Refer to <Advanced Metering Infrastructure Demonstration Test Plans and Assessments v4.0.doc> for additional updated details.

The following conditions apply:

1. The proposed system for demonstration shall be commercially available and shall be of the exact generation proposed in response to this RFP
2. Each Supplier is given approximately 3 weeks of time on Xcel Property to set-up and prepare for the demonstration. The Company team of AMI RFP evaluators will attend and witness demonstrations and, where necessary, conduct the testing with assistance from the Supplier.
   a. Suppliers are required to perform or outline demonstration results in an executive level presentation/demonstrations completed in 1 business day’s duration and,
   b. Suppliers are required to work with Company to provide Company with opportunities to explore system features and capabilities in hands on manner.
3. The actual “demonstration” event is expected to consist of:
   a. Introductions
   b. Description of the system setup and configuration
   c. Discussion toward understanding system architecture
   d. Presentation of operational features and functionality
   e. Performance testing per requirements set out here
   f. Any additional testing or demonstrations that may be offered by the Supplier
   g. Summary

4. The Xcel evaluators' will witness the demonstrations and assess the results against a common criteria, considering no less than feature availability, functionality, compliance to essential requirements and overall performance based on the test criteria identified herein . The assessment results will be used as a component of RFP response assessment.

5. The demonstrations will take place at Company's location in Denver Co. in an assigned lab space. Suppliers will be provided with security access to the setup space.

   HomeSmart
   6981 South Quentin Street,
   Suite A,
   Centennial, Colorado
   80112-3939

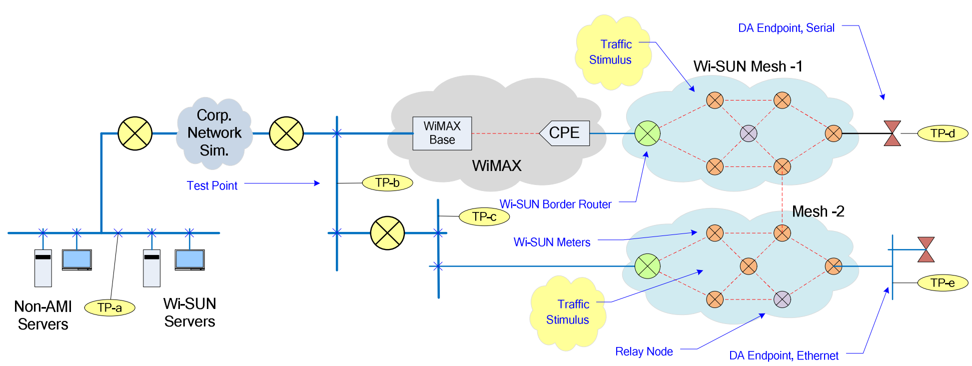
6. Suppliers are required to document the testing undertaken and to provide a detailed report of tests and results within 2 weeks following the completion of the testing.

7. Demonstrations will begin on or about July 18 and be conducted in a sequential manner. Schedules and locations will be coordinated between Company and the Suppliers.

8. All communications will be subject to a Non-Disclosure Agreement (NDA). Company will not conduct demonstration testing without agreed upon NDA's in place.

4.6.2 Demonstration Setup

Suppliers shall supply a profile of the communication environment sufficient to operate the entire system in a stand-alone manner. Below is a sample configuration:



AMI RFP - Demonstration Test Setup

Note the following points:

1. Company shall furnish the following:
   a. Facilities to energize and load up to 30 electric meters (meters provided by Suppliers)
   b. Gas meters (AMI modules to be provided by Supplier)
   c. High speed communication circuit between HomeSmart and Supplier Headend
   d. Electrical power for all network equipment and electric meters

2. Except for equipment and support provided by Company, Suppliers are responsible to supply, install and operate whatever equipment is necessary to complete the required testing. This includes test equipment.

3. No less than two Wi-SUN mesh clusters are required. Mesh clusters must be arranged so as to achieve intermeshing between clusters.

4. At least one Wi-SUN cluster must be configured so as to achieve traffic carriage and testing over no less than 5 radio hops.

5. Suppliers are required to provide-for and simulate real world traffic in the mesh network so as to simulate "contention" and real world AMI traffic scenarios. Traffic simulation stimulus must be of IPv6 AMI type and be no less than that expected to be carried for operational conditions having 5 minute meter read rates and 15 minute transfer cycles in typical residential conditions.

6. Minimum of two Border Routers

7. Company will provide and configure the routing and switching infrastructure to simulate or actuate its internal networking facilities.

8. The demonstration testing includes a requirement to interface to IEEE802.16e, WiMAX compliant AirSpan WiMAX backhaul equipment. Company will supply this component of equipment and assist in any necessary configuration. The equipment is presently set-up and operating at Company FAN Lab in Denver Co. The equipment includes AirSynergy 3.65 GHz base station sectors and WiMAX Pro CPE, operating under NetSpan NMS.

9. Mesh clusters shown in the sketch "AMI RFP – Demonstration Test Setup" should be considered to be figurative. Suppliers should configure mesh clusters to adequately demonstrate their equipment.

10. At the conclusion of demonstrations and within 24 hours, Suppliers must remove all of their supplied equipment.

11. Company will conduct DA performance testing using its own test equipment.

4.6.3 Required Demonstrations

Company expects Suppliers to complete the following demonstrations:

1. AMI Meter Management functionality; no less than:

    a. Accurate handling of LP Data
    b. Service Disconnect/Reconnect Operation
    c. Electric Meter Over the Air Reprogramming (with meters from multiple manufacturers))
    d. Electric Meter Over the Air Meter and Communication Firmware Upgrades (with meters from multiple manufacturers)
    e. Ability to obtain gas ERT reads over the AMI network and performance
    f. Electric bridge meter conversion from ERT mode to AMI mode
    g. User Programmable Space Tests and Functionality (Send customer real time demand, communicate to pole top transformer)
    h. Electric Meter Demand Reset performance.
    i. Verification of ability to retrieve voltage, current, phase angle on demand
    j. Verify ability to bring back fatal alarms from meter/module (Gas and Electric)

k. Verification of Meter Program (Is correct program in meter, alarm if not)
l. Gas Meter Cum Data Transmittal Verification
m. Gas Correcting Device Information Retrieval
n. Testing of field devices used to trouble shoot/test modules in the field and shop

2. AMI Meter Data Collection Performance [Graph]

   a. AMI meter read rates, capacity and reliability
   b. Duration (ms) of successful C12.18 session [Avg, 25%, median, 75% and 99%]
   c. Failure sessions for C12.18 per round. [Rel. frequency vs Failures per round %]

3. Non-AMI (DA oriented) performance, 64 bytes, in the presence of AMI traffic [graph]

   a. Average RTT for 1,2,3,4 and 5 hops [Avg. RTT over 24 hours]
   b. Average Ping Loss Ratio for 1,2,3,4 and 5 hops [Avg. loss% over 24 hours]
   c. Cumulative Distribution Function (CDF) of RTT (5 hops min)[CDF vs RTT ms.]
   d. CDF of Ping Lost Ratio over 5 hops min [CDF vs Failed Ping Requests 5]
   e. Throughput capacity for 1,2,3,4 and 5 hops
   f. SCADA performance over 1,2,3,4 and 5 hops; messaging speed, latency and reliability. This test to be undertaken with Xcel owned and operated test equipment with support and consultation with Suppliers.

4. Interoperability Performance:

   a. Interface to WiMAX strategy (L2, L3, etc.) efficacy of QoS mapping, and preservation of flow prioritization as data traverses Wi-SUN-WiMAX boundaries.
   b. Between Wi-SUN compliant meters running ANSI C12.18 on application layer
   c. Between Wi-SUN compliant meters running DLMS/COSEM on application layer
   d. Between Wi-SUN compliant network nodes, (border, relay and endpoint nodes)
   e. Carriage of IPv4 traffic over IPv6 in 6LowPAN

5. Security Features:

   a. Scope of security features
   b. PKI
   c. End to end encryption

6. Fault tolerance and rerouting; In the event of full or partial failure of:

   a. Meters
   b. Relay nodes
   c. Endpoint nodes
   d. Border Routers
   e. Concentrator server

7. Quality of Service Capabilities including:

   a. Methods of marking traffic types for priority carriage at egress and ingress points
   b. Methods of prioritizing traffic flows based on traffic marking
   c. Methods for managing traffic congestion and performance
   d. Demonstration of prioritization of critical traffic flows in a network that is congested with non-critical AMI related traffic.
   e. Availability of IPv4/6 routing functionality at wired side of border routers
   f. Methods of transporting IPv4 flows over IPv6 Wi-SUN.

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8. Application Support Approach and Methodology
    a. Method by which 3rd party applications can be implemented
    b. Applications that are available
9. Availability and thoroughness of support for the following residential and commercial meter models from Elster, Itron, Aclara/GE and Landis+Gyr:
    a. Class 20 forms 9S
    b. Class 200 Forms 2S, 12S and 16S
10. Full-meter programming, metrology firmware update and communication module firmware update for the following meter suppliers
    a. Itron(Centron II, Centron II Poly-phase)
    b. Landis+Gyr (Focus AXD, Focus WR AXD, S4e)
    c. Elster (A3T, A3RAL, A3RALNQ,etc)
    d. Aclara/GE(I-210, KV2c)
11. RF performance:
    a. Demonstrate available modulation modes and dynamic fallback modes
    b. Demonstrate transmit power capability per mode and noise figure
    c. Demonstrate that theoretical link budgets tracks with practice
12. Packaging and Powering
    a. Demonstrate the manner in which the WMN border routers will be physically integrated to WiMAX CPE and provide 8 hours of uninterrupted service in event of power failure and support battery charging/maintenance and monitoring for all components.
    b. Show all system components including but not limited to: typical border routers, relay nodes, endpoint nodes, meters, etc.
13. Testing for AMI modules for gas meters (devices listed in Table 7 below)
    a. Visual inspection and proof testing:
        i. Demonstrate compliance to ANSI B109 series standards including but not limited to integrity of gaskets, venting and housing for weather protection.
        ii. Demonstrate alignment of module shaft to meter wriggler and the alignment of the module shaft to the index.
        iii. For wriggler operated modules, demonstrate that the module does not alter the measurement accuracy of the meter.
    b. Fit test: Demonstrate meter module alignment, drive geometry, and backlash/lost motion for “spotting the dial” tests, ease of installation, ability to follow module manufacturers’ installation instructions on meter vintages.
    c. Programming: demonstrate that all modules can be programmed per module manufacturers’ installation instructions.
    d. Count accuracy: Through actual operation of modules; demonstrate that the transmitted system read is at all times accurate within 1 count of the least significant visual index read.

e. Data handling and auditing: Demonstrate that all documentation is available in English language and that the meter functions in accordance with documentation including but not limited to:

i. drive rate,
ii. start read,
iii. cumulative meter read that matches the visual index read,
iv. number of dials information and methods used to determine cumulative reading,
v. time stamping of reads;
vi. which data is retained in the module,
vii. which data is transmitted to the network,
viii. how frequently the data is transmitted,
ix. how an index change in the field is processed and the module re-programmed for the replacement index,
x. process for reusing the module on a different meter,
xi. battery change process,
xii. alarms originating from within the module and alarms that are generated by the network or back office,
xiii. interval usage data, how the module recovers when the network is unavailable for 2 days, 1 week, 1 month,
xiv. how the module programming and current read is determined when auditing at the meter site,
xv. installation of the modules in a gas only service area,

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xvi. capability of the system to read the existing installed population of 100G ERTs

Table 7 - Gas meters that will be used for evaluating and/or testing AMI modules

Meter Manufacturer	Model(s)	Visual numb er of	Index type	Visu al read	Billin g units	Numbe r of billing	Wriggl er Drive	Meter pulse output	Visual and fit evaluat	Install and operate
Elster, American Mete	AL175, AM225, AL250, AC250	4	pointer, front mount	CCF	CCF	4	1'	N/A	Yes	1 module
Elster, American Mete	AL175, AM225, AL250, AC250, AL425, AC630	4	pointer, front mount	CCF	CCF	4	2'	N/A	Yes	1 module
Elster, American Mete	AL800, AL1000	5	pointer, top mount	CCF	CCF	5	5', 10'	N/A	Yes	1 module
Elster, American Mete	AL1400, AL2300,	5	pointer, top mount	CCF	CCF	5	5', 10'	N/A	Yes	1 module
Metric	80B, 250B, 500B	5	pointer, top mount	CCF	CCF	5	5', 10'	N/A	Yes	No
Rockwell, Sensus	175, 250, 275, 31	4	pointer, front mount	CCF	CCF	4	2'	N/A	Yes	1 module
Sprague, Schlumberger, Itron	175, 240, 250	4	pointer, slanted front mount	CCF	CCF	4	2'	N/A	Yes	1 module
Dresser, Roots, GE	LMMA Counter drive, 8C, 15C, 3M, 5M, 7M, 11M	5	MFG odometer or vertical index on ID	CCF	CCF	5	10'	N/A	Yes	1 module
Dresser, Roots, GE	LMMA Counter drive, 16M	6	MFG odometer or vertical index on ID	CCF	CCF	6	100'	N/A	Yes	1 module
Dresser, Roots, GE	B3 Counter drive, 8C, 15C, 3M, 5M, 7M, 11M	5	MFG odometer or vertical index on ID	CCF	CCF	5	10'	N/A	Yes	No
Dresser, Roots, GE	B3 Counter drive, 16M, 38M, 56M	6	MFG odometer or vertical index on ID	CCF	CCF	6	100'	N/A	Yes	No
Dresser, Roots, GE	B3TC with instrument drive, 8C, 15C, 3M, 5M, 7M,	6	MFG odometer or vertical index on ID	CCF	CCF	6	100'	N/A	Yes	No
Dresser, Roots, GE	B3TC with instrument drive, 16M	6	MFG odometer or vertical index on ID	CCF	CCF	6	1000'	N/A	Yes	1 module
Dresser, Roots, GE	B3TC with Mfg Form A pulse out, 3M, 5M,	5	MFG odometer	CCF	CCF	5	N/A	10', circular connector	Yes	1 module
Romet	TC with Mfg Form A pulse out, 3000,	5	MFG odometer	CCF	CCF	5	N/A	10', circular connector	Yes	1 module
Mercury/Honeywell	TCI	5	MFG digital	CCF	CCF	5	N/A	100' solid flying lead	Yes	1 module
Mercury/Honeywell	Mini AT	6	MFG digital	MCF	MCF	6	N/A	1000' screw terminal	Yes	1 module
Mercury/Honeywell	Mini Max	5	MFG digital	CCF	CCF	5	N/A	100' screw terminal block	Yes	1 module

5 AMI Meter Requirements

5.1 Electric Meter Requirements

5.1.1 Interoperability and Standards

1. Meters shall be built to ANSI C12 standards
2. Meters shall have an interface capability to operate with communication modules furnished by multiple potential Suppliers; the communications modules will reside under the meter cover and collectively support the functional and non-functional requirements as specified in this RFP.
3. The communication module furnished by potential Suppliers shall have an interface capability for the life of the meter.
4. There shall be transparent IP routing to the meters. Meters and control devices shall be both IPv-4 and IPv-6 addressable
5. All electric meters shall have a 0.5% or better accuracy class

5.1.2 Meter Feature Requirements

1. Both residential and commercial type meters shall be equipped with temperature sensors capable of measuring meter temperature for detection of “hot sockets”
2. Hot socket algorithm shall open the service switch at extreme temperatures. Temperature thresholds shall be configurable. Control algorithm shall include reporting of at least 8 hours of load and temperature information prior to interruption. Optionally automated or manual interruption based on system alert.
3. Both residential and commercial type meters shall be equipped with tilt/motion sensors.
4. Tilt/motion sensors shall be captured/processed at power down to differentiate removal from normal outage
5. The meter will be required to support at-least 2 independent clocks, and both shall be required to independently and optionally support DST. The two clocks shall function from the same time-base (basic clock “tick”) but shall have independent clock values so that the company can support, for example, different time-bases for load profile data (reported to the master back office applications as Universal Time) and for local representation (for example, governing local registration for TOU and for customer display). That can best be accomplished by allowing all time-based meter functions to be tagged to either of the requested independent clocks. Various meter functions shall be assignable to either meter clocks. This would support local time offsets as well as load profile recording without time discontinuities due to DST shifts. See also Section 6.4 “Timing and clock References”
6. Residential meters shall have no batteries (no real-time clock) and operate based on network time that is distributed upon system power up.
7. Transformer rated meters shall have the option to include potential and current ratios in the transmitted metered data.
8. The meter shall be able to self-register on the AMI network and communicate to the field network setup tool whether or not all aspects of the meter and its communication with the AMI system are operating properly.
9. Load profile data shall be recorded and date/time stamped at the end of each interval. The date and time stamping of load profile data shall be consistent with ANSI C12.19
10. The meter shall be configurable to support delivered, received, net and absolute power at the meter.
11. The meter shall support a configurable “disconnect on detected DG” flag. Setting this flag would trip the service disconnect when DG is detected. Parameters for DG detection would include recognizing reverse flow at a configurable level (watts to kilowatts) over a configurable interval (five seconds to one hour) to prevent false triggering.
12. The meter shall support a network time synchronization of 1 second or better and be able to time stamp its voltage peak to an accuracy of 1 second.

13. Load profile interval shall be configurable from 1 minute to 24 hours. (1 min, 2 min, 5 min, 10 min, 15 min, 30 min, 60 min, 1 day)
14. Both meters and communication devices must be capable of hard resets to factory default conditions by local means without shipping back to manufacturer
15. To facilitate meter processing and installation, customer meters shall be uniquely identifiable by both bar coding and electronic communication

5.1.3 Upgradeability and Configurability

1. The meters shall be equipped with 4x the level of memory storage than required by the initial meter specification.
2. The system shall have firmware/code image size that is 2x the size at initial deployment for code changes associated with metering and power supply
3. The system shall have 2x the peak quantity of used RAM at the time of initial deployment for code changes associated with metering and power supply
4. The system shall have firmware/code image size that is 4x the size at initial deployment for code changes associated with communications
5. The system shall have 4x the peak quantity of used RAM at the time of initial deployment for code changes associated with communications.
6. Meters shall support a disciplined clock in order to minimize clock adjustments that result in discontinuities in time. The clock shall be synchronized to NIST master clock with a maximum error of 1 Second. This will provide more graceful time management, will eliminate both “short” and “long” intervals from interval data recordings, and will provide more accurate demand intervals without having to invalidate intervals due to time adjustment.
7. Residential meters, equipped with a service switch, shall have the ability to limit load/service. The load limit shall be configurable such that multiple configurable steps (e.g. 90% of rated capacity, 75% of rated capacity, etc.) can be configured in the AMI Meter.
8. If bi-directional functionality is required to be activated in the meter, the meter shall be able to be re-programmed remotely over the air. This reprogramming event will be logged in the meter and sent back to the Headend immediately.
9. Data sent from meters shall be configurable as to whether interval data, register data, event data or all shall be sent during routine or on-demand meter read requests.
10. The meter shall permit TOU, CPP and PTR time period to be remotely configurable.
11. The meter shall permit its firmware and programs to be remotely downloadable without loss of register data.
12. Meter shall report failures e.g. communication failure after reboot, program lock-up, etc. following a software/firmware upgrade within 15 minutes after start-up of new program. Reportable failures shall include billing information loss or loss of electric service. Meter failures to report shall be configurable in the meter program.
13. Firmware and programs shall revert back to old functioning versions if the new one fails or upon utility command and meter will report that action and status. There shall be room to store previous image, current image and downloading image.
14. Register meter functions shall be programmable both remotely and locally.
15. Handling of received energy shall be configurable in the meter. e.g. sum of delivered and received energy, ignored, net, etc.

5.1.4 Availability

1. The meter shall continue to record data during a communication failure.
2. The meter shall be recognized by the network and registered within 4 hours of installation.

5.1.5 Connect, Disconnect or Limit Service

1. All self-contained residential meters class 200 (Forms 1S 2S and 12S) and class 320 (Forms 2S and 12S) shall be able to remotely connect/disconnect/limit electric service to customer premises.
2. The service switch shall be rated for at-least 10,000 service disconnect operations
3. The meter shall be able to limit demand served to the customer by a remote utility on-demand request or through utility pre-configured rules (e.g. 90% of rated capacity, 75% of rated capacity, etc.)
4. The meter's disconnect switch shall be capable of inhibiting the close operation when there is voltage on the load side to prevent equipment damage or personal injury.
5. The remote disconnect shall be integrated with the meter rather than a collared solution for meter types that have been identified as requiring a disconnect switch.
6. The meter shall permit remote changes to the threshold for load limiting from MDM or Headend. Thresholds shall be configurable.
7. The Remote disconnect shall have a rating consistent with meter class rating at 60% lagging power factor
8. The meter shall re-energize a configurable number of times automatically after a configurable delay if meter trips off because the demand/energy limit is exceeded.
9. The meter shall acknowledge load limit command successful to Headend
10. Meter shall acknowledge and communicate open/close status after operating command is issued and shall be confirmed by Headend.
11. The remote connect/disconnect switch shall be operable through the optical port.
12. The meter disconnect event (remote or local) shall not generate a last gasp message.
13. The meter shall be optionally able to disconnect upon power outage and delay reconnecting upon power restoration with a configurable randomized delay between a T-min and T-max for:
    a. Soft system recovery after outages
    b. Installer safety

5.1.6 Visible Access to Data

1. Meters equipped with a service switch shall provide for an external indication of the switch status discernable to a customer or Company employee on site.
2. Meter display shall provide date and time as specified by the utility. The display shall also display measured quantities in engineering units.
3. Displayed data shall exactly match stored and transmitted data
4. Meters shall be capable of displaying registers of all possible metered data. Displayed data must show associated metrics/unit of measure.
5. Meter display shall include status of FAN communication link
6. If equipped with HAN, meter shall display status of HAN communication.
7. A visual disk emulator shall be provided on all meters.
8. Meter shall be able to operate in alternate and test modes and display configurable alternate and test mode display sets
9. Meter shall be placed into alternate and test modes locally. Test mode to have configurable time out period (reverting to normal mode) and ability to be set to normal mode remotely.
10. Normal and alternate displays to include error and warning conditions

5.1.7 Demand Response

All control and reconfigurations commands must be confirmed by field devices within 15 seconds.

5.1.8 Distributed Generation

1. The meter shall collect delivered, received and net cumulative values as well as interval data that are signed. Delivered cumulative shall be equal to the sum of delivered intervals, received

cumulative shall be equal to the sum of received intervals. Both time duration and energy threshold shall be configurable in seconds.

2. Meter display shall be configurable to display all or any of the measured quantities identified in item 1 above.

5.1.9 Installation and Maintenance

1. The communication module in the meter shall have Unique ID's for: LAN, WAN.
2. The meter shall have an indelible unique serial number over the life of the AMI system.
3. The meter shall have a unique ID for HAN communication.
4. Upon installation, the meter shall optionally recognize the service type and issue alarm messages for unrecognized services. The meters shall have functionality that enables to individually disable service level alarms.
5. Meter shall be able to identify itself to field network setup tool and provide access to its data and configuration settings at installation time, and later in support of ongoing operations & maintenance activities subject to security authorization.
6. The meter performs self-check and reports results to installer field tool, local display and to the AMI network. Self-checks to include integrity of the HAN communications card (if present) and AMI network communication card and ability to communicate with local collector (AMI communication network architecture dependent).

5.1.10 Meter Reading - On Demand

1. The meter shall be able to provide peak demand during a defined demand window and on-peak/off-peak usage
2. On the occurrence of an on-demand interval data read, the meter shall send data since the last successful read and other associated register and diagnostic information.

5.1.11 Meter Reading – Scheduled

1. The meter shall complete a self-read and store the value for each channel register of data.
2. Residential type meters shall be configurable to provide at least the following register and interval data:
    a. kwh (delivered and received)- Individual phase and total
    b. Kvarh(delivered and received) – Individual phase and total
    c. Internal meter temperature
    d. Voltage (magnitude and angle) - Individual phase and total
    e. Current (magnitude and angle)- Individual phase and total
3. Commercial type meters shall be configurable to provide at least the following register and interval data:
    a. kwh (delivered and received) - Individual phase and total
    b. Kvarh (delivered or received)- Individual phase and total
    c. Internal meter temperature
    d. Voltage (magnitude and angle) - Individual phase and total
    e. Current (Magnitude and angle)- Individual phase and total
    f. Kvah- Individual phase and total
4. Voltage resolution reported to Headend shall be 0.1V or better
5. Power Factor calculations shall include at least the following: Average, max, min, coincident, etc.
6. Supplier shall provide detailed description of each of the options available for power factor calculation
7. Residential meters shall be configurable to measure both integrated and instantaneous values (Per phase and total) for the following: In this context, “instantaneous” means a linear average over 1 second:
    a. KW

   b. Kvar
   c. Voltage
   d. Current
   e. Kva
8. Commercial meters shall be configurable to measure both integrated and instantaneous values (Per phase and total) for the following: In this context, "instantaneous" means a linear average over 1 second:
   f. KW
   g. Kvar
   h. Voltage
   i. Current
   j. Kva
9. The meter shall accommodate a minimum of 60 days of load profile data with 5 minute intervals for at least 4 channel data
10. Meters shall support TOU and critical peak pricing capabilities:
    a. 4 TOU rates
    b. 1 Critical peak pricing rate
    c. Ability to switch between time zones
    d. Ability to switch between standard time and daylight savings time
    e. Support for 4 seasons.
    f. Support advance calendar for at least 20 years including holidays

5.1.12 Meter Reading - Real time

Any metered quantify shall be available for a push or pull to the Headend in real-time with latency not to exceed 20 seconds

5.1.13 Outage Management

1. The meter shall be capable of sending a message if load side voltage is detected on a disconnected meter. Latency not to exceed 20 seconds.
2. The meter shall maintain sufficient function for a sufficient amount of time to differentiate between an outage and a PQ event.
3. The service switch shall operate if voltage less than a configurable threshold is detected for a configurable period of time.
4. The service switch of the meter shall operate if voltage greater than a configurable threshold is detected for a configurable period of time. If the service switch is operated, Company shall receive notification of the event.
5. Reconnection of the service switch of the meter shall occur automatically once the voltage has returned within the acceptable limits for more than a configurable amount of time. If the service switch is operated, Company shall receive notification of the event.
6. The meter shall detect and send a last gasp/tamper alarm to the Headend. Detection shall be possible after the meter is removed and before it stops communicating.
7. The meter shall be able to send a last gasp message over the communications network during an outage or removal.
8. At the system-level, meters shall remain operational after an outage for a period of time that is sufficient to achieve:
   a. 100% reporting on single outage
   b. 90% reporting on outages of up to 1000 meters
   c. 50% reporting on outages of up to 10,000 meters
   d. 30% reporting on outages that are system wide

9. Measurements of momentary interruptions, momentary interruption events and sustained interruptions shall be consistent with IEEE Std 1366-2012. In the case where IEE 1366 standard changes, the new definition shall supersede the old.
10. A single momentary interruption event includes all momentary interruptions experienced by the meter within a configurable period (e.g. 5 minutes, etc.). Service must be restored within a separately configurable time period (e.g. 5 minutes) to be classified as a single momentary event.
11. The system must be capable to report service restoration from 100% of meters within 10 minutes of restoration. System must support outage confirmation (head-end to meter and back) to determine online status to support field crews.
12. An interruption of less than a configurable time period (e.g. 5 minutes) shall be considered a momentary interruption and shall be logged by the meter as a momentary interruption.
13. An interruption of more than a configurable time period (e.g. 5 minutes) shall be considered a sustained interruption and shall be logged by the meter as a sustained interruption. The sustained interruption includes all the switching events from the initial interruption to full restoration of the sustained interruption event.
14. Data recorded by the AMI meters will be used to calculate Momentary Average Interruption Frequency Index (MAIFI) and Momentary Average Interruption Event Frequency Index ($MAIFI_E$). MAIFI includes all momentary interruptions that are not part of a sustained interruption. $MAIFI_E$ includes all momentary interruption events that are not part of a sustained interruption.
15. A single interruption shall trigger meter logging.
16. Momentaries shall be reported up to the Headend with the next scheduled meter read.

5.1.14 Security

1. Encryption of data stored in meter memory and in the transfer from CPU to memory shall be required.
2. The meter shall lock/disable chip diagnostic and programming ports (JTAG)
3. Provisions for secure local access shall be made available through the network or direct connection to the meter (via optical port).
4. The meter (and Field Tool) shall include authorization/authentication for local meter data download attempts.
5. The communication module shall be integrated with the meter under the cover.
6. The meter shall log all login attempts and support a lockout for a configurable amount of time upon repeated invalid attempts. Supplier shall provide list of other security events that the system is capable of logging.
7. Meter shall support, at minimum, symmetric key lengths of 128 bits.
8. Supplier shall provide detailed cryptographic key management description explaining how cryptographic material is provisioned, used, stored, and deleted within the system.
9. The communication module shall explicitly deny an information flow based on illegal message structure. The communication module shall have provisions to detect and thwart a message replay attack e.g. as per ANSI C12.22
10. Meter shall employ mechanisms that ensure device integrity from external tamper and compromise.
11. Meters shall comply with cyber security programs based on good industry standards such as NIST SP800-53 and SP800-82.
12. Meter shall supply a meter-to-Headend, cryptographic solution which assures the confidentiality of the meter's data while in transit.
13. Meter shall supply mechanisms which allow for secure device authentication, registration, and revocation.
14. Meter shall supply cryptographic mechanisms or materials which allows for unique device identification, authentication and communications.

15. Meter shall supply cryptographic mechanisms or materials which allows for group access
16. Meter shall supply mechanisms which audit and store all security related events including all access and modifications events within the system.
17. Meter shall supply a security audit store which includes the date and time of the event, type of event, user identity, and the outcome (success or failure) of the event.

5.1.15 Reliability

1. Suppliers shall submit accelerated life testing results for all the system components, substantiating the system's life and identifying top failure causes.
2. Meter must survive and function properly without losing data or programs through repetitive short-term power outage cycles as might be experienced by recloser operations
3. Meter time must be settable through the communication medium and the meter shall keep accurate time with a drift rate of no worse than 1 minute per year and in accordance with Section 7.4 "Timing and Clock References"
4. Some meters identified to support near real-time operations will require a low latency network to support Company's ADMS or SCADA needs.
5. Meter failure rate must be less than 0.5%/yr. for the first two-years and less than 0.3% for the remainder of the 20 year system service life.

5.1.16 Storing, Logging and Reporting Events

1. The meter shall be configurable as to what events are logged by the meter. Event messages for transmission and priority shall be determined by Company.
2. Meter shall send acknowledgement of a successfully completed or failed electric service connect/disconnect/limit event to the Headend latency not to exceed 20 seconds.
3. The meter shall log the date and time stamped establishment of load limit set-points, when load limits are exceeded, support for solicited and unsolicited reporting shall be available.
4. The meter shall log all local (and remote) meter data download attempts and the requester ID. The system shall support solicited and unsolicited reporting
5. The meter shall be able to detect loss of load (greater than a configurable period of time) on the customer side of the meter that is not related to a remote disconnect, log the event, and send an event message to Headend. When load is restored, the meter shall log the event.
6. The meter reinstallation events shall be sent to Headend immediately upon reinstallation along with any unsent tamper events.
7. An event generated when the meter is reinstalled is different from the event generated if the meter is initially installed (provisioned) or re-energized (e.g. after an outage). This is to avoid transmission of useless information to the enterprise systems because of non-tamper related events.
8. Meter's internal clock shall be synchronized in such a manner that the meter data that includes register and interval data shall not be affected and shall log the event
9. Meter shall be able to detect and log communications link failures upon failed communications initiated from the meter.
10. Meter shall be able to send an alarm/event to the Headend when a configurable number of consecutive communications link failures are detected (e.g. three consecutive link failures).
11. Meter communication module shall be able to periodically record the communication signal strength and report it back to the Head-end as part of all communication transactions.
12. Each meter shall be capable of capturing and recording a time stamped instantaneous voltage at configurable intervals ranging from 1 minute to 1 hour.
13. Each meter shall be capable of sensing and capturing high/low voltage variations with reference to user definable set points and, upon exceeding the predefined limits, send notifications.
14. The meter shall support an indelible event log sufficient to contain entries for at-least 60 days after which oldest entries are over-written first.

15. Meters with internal service switch shall log all disconnections and connections within its indelible event log.
16. The meter shall communicate to both its event log and the Headend any reactivation (reconnect) and disconnection events.
17. The meter shall log to its indelible event log messages (informational and functional) received from the Headend with the meter date/time and message code.
18. The meter shall detect and store as an event that an electrical parameter (voltage, current, load) has differed from a specified threshold for a certain period of time.
19. The meter shall immediately transmit any events that indicate a security threat. The transmission of the data must continue until the AMI Headend responds with a validation the data was received.

5.1.17 Tamper/Theft Detection

1. The meter shall detect physical tampering, such as, meter removal, case/cover removal, removal from socket, etc. and generate a tamper event.
2. All tamper related events shall be stored in the meter's event log. Events shall be stored for at least 60 days.
3. The meter shall be capable of detecting and alarming on an inverted meter condition.
4. The meter shall be capable of sending a removal tamper event before communications are interrupted.
5. Meter tamper events shall be sent with a higher priority than normal status messages.
6. For each tamper event, the meter shall transmit to the Headend and locally log the following information about the event: timestamp, tamper status (event type), meter ID.
7. In real-time the AMI-head and data analytical applications shall be able to determine which meters with an open disconnect switch have secondary voltage.

5.1.18 Power Quality

1. The meter shall have report by exception capabilities for selected parameters e.g. voltage, demand, etc. for operational purposes.
2. The meter shall be capable of recording both instantaneous and average configurable voltage, current, power factor, kWh, kvarh, and kW values during each interval
3. Meter shall monitor voltage and current in order to detect power quality variations according to CAN/CSA 61000-4-30, IEEE 1159, CBEMA / ITIC and IEC 61000-4-30 standards.
4. Meter shall allow authorized Company employees to retrieve any recorded device information including logs both locally and remotely (on-demand). Local communication has priority over remote.
5. Both meter and communication infrastructure shall support remote desktop access to the meter using meter manufacturer's native configuration software (e.g., Metercat, PCPro, etc.) over an IPv4 and/or IPv6 connection.
6. Meters with power quality capabilities shall store the power quality data for a period of up to 60 days.

5.1.19 Instrumentation Profiling Data

When equipped with instrumentation profiling data, meters shall be required to capture date and time for minimum, maximum, instantaneous and average values per phase and total for the following values:

a. Voltage
b. Current
c. Temperature
d. power (KW)
e. reactive power (KVAR)

f. Apparent power (KVA)
g. Power factor
h. Harmonics

5.2 Meter Requirements for HAN Support

5.2.1 HAN Interface – Hardware and Communications

AMI meters and system must have the ability to support IEE 2030.5 standard for interface with 3rd party HAN providers. Xcel requires the AMI solution to support communication with HAN, though anticipates it will be selectively deployed (see Section 5.8). The Supplier may propose solutions with technology embedded in all, or only select meters.

5.2.2 HAN Interface- Data Requirements

Using the HAN interface hardware and communications protocol, the meters demand data must be made available to 3rd party HAN providers at a granularity of 1 minute or less.

5.3 Meter Read Performance Metrics

5.3.1 Baseline Read Rates

All meters, excluding the bellwether meters, shall record interval, register and events data every 15 minutes and complete transmission of this recorded data to the Headend, at an interval that does not exceed every 4 hours and meeting or exceeding data transmission completion reliability criteria of 99.9% on first attempt.

5.3.2 Fast Transmission Read Rates

Where meter read rate performance is considered to be “Fast”; all meters, excluding the bellwether meters, shall record interval, register and events data every 15 minutes and complete transmission of this recorded data transmit to the Headend, at an interval that does not exceed every 15 minutes and meeting or exceeding data transmission completion reliability criteria of 99.9% on first attempt.

5.3.3 Five Minute Interval Read Rates

All meters, excluding the bellwether meters, shall record interval, register and events data every 5 minutes and complete transmission of this recorded data to the Headend, at an interval that does not exceed every 4 hours and meeting or exceeding data transmission completion reliability criteria of 99.9% on first attempt.

5.3.4 Register readings - Auto scheduling

The AMI Head-End Application shall initiate scheduled meter read requests and collect at least 99.9% billing quality meter register reads on first attempt.

5.3.5 Register / Interval readings – Auto scheduling

The AMI Head-End Application shall initiate scheduled meter interval data read requests and collect 100.0% billing quality interval meter reads for at least 99.9% of the scheduled meters on first attempt.

5.3.6 Register / Interval readings – On Demand readings from other sources

The AMI Head-End Application shall successfully process on-demand meter read requests initiated thru the MDM and CSS (and other designated systems such as web interface).

Data retrieval directly from meter - response time shall be < 20 seconds 99.9% of the time on first attempt.

Meter data retrieval from AMI Head-End Application database - response time shall be <10 seconds 99.9% of the time on first attempt.

5.3.7 Register / Interval readings – On Demand readings from Headend

The metering system shall successfully process on-demand meter read requests initiated within AMI Head-End Application (user menu). If not successful, AMI Head-End Application shall produce a specific error message at a configurable duration as set by Company.

Data retrieval from meter - response time shall be < 20 seconds 99.9% of the time on first attempt.

Data retrieval from AMI Head-End Application database - response time shall be <10 seconds 99.9% of the time on first attempt.

5.3.8 Register / Interval readings User initiated data output request

Data collected from on-demand meter read requests may include: register reads, interval data for a configurable period, service switch status, service voltage, or any meter logs that may include events, warnings or alarms.

Data processing extraction time frames must not exceed 15 minutes per 250,000 register or interval records retrieved and successfully written to an output file.

5.3.9 Interval readings Gap retrieval

The AMI Head-End Application shall successfully re-request interval data from the meter when data collection has encountered gaps in the data. The gap retrieval process shall be automated and configurable in the duration (length of time to try to recover data) and number of retry attempts (every XX minutes/hours).

Suppliers shall indicate the manner in which these options can be configured.

The gap retrieval process should successfully retrieve 100% of the missing interval data when the interval data is available in the meter tables. There shall be no discontinuities to energy registration for DST and meter clock resets. The total pulse counts or energy registration from the intervals shall equal exactly the total register readings.

5.3.10 Register readings recovery

The AMI Head-End Application shall successfully re-request register data from the meter when data collection encounters missing register reads. The retrieval process shall be automated and configurable in the duration (length of time to try to recover data) and number of retry attempts (every XX minutes/hours).

Suppliers shall indicate the manner in which these options can be configured.

The retrieval process shall successfully retrieve 100% of the missing register data when the register data is available in the meter tables on first attempt.

5.3.11 Demand Reset Performance

The AMI Head-End Application shall successfully perform automated and on request demand reset functions 100% of the time on applicable demand meters. The demand reset process shall be able to be initiated upon request and shall be automated and configurable through an auto schedule such as a schedule established for billing cycle meter reading collection. In the event a demand reset is unsuccessful the AMI Head-End Application shall initiate a configurable number of retry attempts (every XX minutes/hours).

Suppliers shall indicate the manner in which these options can be configured.

5.3.12 Accuracy of Delivered Meter Reads

Data collected from field devices and processed thorough the Headend Database, shall accurately reflect customer consumption taking into account such things as meter multipliers, pulse multipliers, or data adjustments of any nature.

5.3.13 Precision of delivered data

Precision of delivered data shall no less than precision of the original source data precision.

5.4 Bellwether Meters Performance Requirements

5.4.1 Support for Advanced Distribution Management System (ADMS)

1. The AMI system shall support the use of no less than 20,000 meters, referred to as "bellwether meters", for use as distribution parameter sensors for ADMS in support of applications such as IVVO. 10,000 shall be located in PSCo and the rest in the other company jurisdictions.
2. Bellwether meters are evenly distributed proportionately to electric feeders throughout Company service territory. Refer to the "Electric Distribution Points.xlsx" attachment for details on location.
3. Approximately 50% of the devices are of residential type. The balance is of a commercial type.
4. Residential bellwether meters shall measure, record and transmit no less than the following parameters:
   a. kwh (delivered and received),
   b. Kvarh (delivered and received)
   c. Voltage,
   d. Current
   e. Temperature
5. Commercial bellwether meters shall measure, record and transmit no less than the following parameters:
   a. Kwh (delivered and received),
   b. Voltage (per phase),
   c. Current (per phase),
   d. Kvarh (delivered and received),
   e. Kvah,
   f. Power Factor,
   g. Temperature
6. Data accuracy shall be no less than 1 incorrect parameter received in 1 million parameters sent from meters to the Headend.
7. Load profile interval data from all bellwether meters shall be made available to the Headend no more than 20 seconds after the close of every meter load profile interval.
8. Load profile data from bellwether meters shall be processed by the Headend and made available to other applications e.g. MDM no more than 30 seconds from the close of every meter load profile interval.
9. AMI Headend shall process meter raw interval data, usually in pulse counts, and make it available in engineering units to other systems such as ADMS. As an example, volt-hours interval data in pulses from the meters shall be processed by the Headend and made available to other systems as average voltage values through integration interfaces.

5.4.2 Bellwether Read and Transmission Rates – Residential Meters

Interval and register data from bellwether residential meters shall be collected and transmitted to ADMS via the Headend at intervals that do not exceed 5 minutes. The AMI system shall make this data available 99.9% of the time to ADMS.

5.4.3 Bellwether Read and Transmission Rates – Commercial Meters

Data from bellwether commercial meters shall be collected and transmitted to ADMS via the Headend at intervals that do not exceed 5 minutes. AMI system shall make this data available 99.9% of the time to ADMS.

5.4.4 Option - Total Voltage Harmonic Distortion

As an optional response including pricing on Xcel Energy AMI RFP pricing Template v4.xlsx repeat section 5.4.1 Support for Advanced Distribution Management System (ADMS) with the addition of:

a. In line 5.4.1 – line 4 add f.% Total voltage harmonic distortion
b. In line 5.4.1 – line 5 add h.% Total voltage harmonic distortion

Use Xcel Energy AMI RFP pricing Template v4.xlsx, “Baseline AMI Meters” TAB and expand on the block of options that can be offered by Suppliers.

5.5 Requirements for Headend Application

5.5.1 Availability

1. Headend shall log information (i.e. retrieval pathway) associated with both successful and unsuccessful retrieval of missing/incomplete meter data to aid in troubleshooting. The Headend shall provide specific details on success and failures
2. Headend shall monitor and measure both communication and device availability metrics for metering endpoints and network equipment.
3. Headend shall enable customer notification of communication status with HAN devices within 30 minutes of enrolling them. Expected value is 2 minutes 90% of the time.
4. Headend shall be able to remotely detect network communications problems including loss of redundant communications pathways, diminishing signal strength, repeated delays in reporting etc.
5. The Headend shall support configuration of Quality of Service parameters in the underlying communication network.

5.5.2 Connect, Disconnect or Limit Service

1. If a command to disconnect or reconnect a meter fails, Headend shall be capable of automatically retrying the command. The number and frequency of automated retries shall be configurable with grouping capabilities with strategies behind them. (Meter type, rate class, geography, individual meter, etc.)
2. Headend shall transmit to the meter a load limiting request initiated by either the MDM or user logged into the AMI GUI
3. Headend shall have the ability to schedule; reschedule and cancel remote connect, disconnect and demand limiting commands for future dates/times.
4. The Headend shall support both human and machine initiated connect/disconnects

5.5.3 Customer Access to Data (If HAN is enabled at the meter)

1. Headend shall send rate change event schedule information to the meter with a future effective date and time. Expect a minimum of 12-24 hours.
2. Provide usage by billing period up to last interval on-demand
3. Headend shall provide notification when system defined or user defined "peak" kW is exceeded.

5.5.4 Data Analysis - Reporting

1. The Headend shall produce system report for each meter indicating the average RSSI and SNR levels for system analytics and optimization.

2. The Headend shall produce system load profile data for gas and electric that would be suitable for use by aggregators for studies to facilitate growth planning.
3. Headend shall have the capability to localize the source of the communication failure and produce diagnostic and trend reports to support operations and maintenance efforts.
4. The Headend shall support the definition, creation, management, and delivery of predefined reports, which can be customized based on all database fields in the system. The Headend shall also provide a mechanism to save these reports in different formats e.g. CSV, xml, etc. from within its environment.
5. The Headend shall provide reports for performance metric evaluation based on Company's Requirements (e.g. response times, message delivery reliability, Headend system availability, communications network availability).
6. The Headend shall provide facilities to automate routine report generation.
7. The Headend shall generate a status report daily that includes information regarding anomalies and issues affecting the integrity of the metering system or any component of the metering system including information related to any foreseeable impact that such anomalies or issues might have on the metering system's ability to collect and transmit meter reads. This would include confirming the successful collection and transmission of meter reads or logging all unsuccessful attempts to collect and transmit meter reads, identifying the cause, and indicating the status of the unsuccessful attempt(s).
8. At the completion of every read schedule, the Headend shall generate a status report that confirms the accuracy of the meter reads. e.g. The report shall be able to identify any meter related errors that might affect the accuracy of the data.
9. At the completion of every read schedule, the Headend shall generate a status report that monitors time and reports any deviations.
10. At the completion of every daily read period and following a transmission of meter reads, the Headend shall generate a status report that confirms whether time synchronization within the metering system or any components of the metering system has been reset within the daily read period.
11. The Headend shall have the ability to export AMI-specific, meter, and network events list.
12. The Headend shall have the ability to configure AMI-Headend specific, meter, and network events that can be transmitted and the frequency.
13. AMI system shall detect and report hot-socket conditions to the Headend.

5.5.5 Data Collection

1. Headend shall support CCF and MCF measurements for gas
2. Headend shall support measurement of temperature and pressure for gas

5.5.6 Data Reporting

1. Headend shall provide load profile data reports at a frequency configured by the Company, e.g. several times daily, weekly, monthly, etc. Report shall contain all of the data from Load profile configured meters.
2. Headend shall provide an energy consumption report at a frequency configured by the Company, e.g. daily, weekly, etc. The report shall contain the meter serial number, current consumption data, demand reset success, etc.
3. Headend shall provide a zero usage report at a frequency configured by the Company. e.g. daily, weekly, etc. The report shall contain the meter serial number, current consumption data, status, and diagnostic data.
4. Headend shall provide a report on meters not communicating at a frequency configured by the Company, e.g. daily, weekly, etc. The report shall contain the meter serial number, current consumption data.

5. Headend shall provide roll-up network and reading performance reports, daily, weekly, monthly, yearly etc. The report shall contain performance categories as specified by the utility. I.e., by route, by area, by zip by grouping.
6. AMI Headend application will generate internal AMI application synchronization report listing synchronization errors with company MDM.

5.5.7 Distributed Generation

Headend shall collect the following metering data and export the data. in a user defined format:

a. Delivered values
b. Received values
c. Net cumulative values
d. Interval data that is assigned.
e. Delivered cumulative values (sum of all delivered intervals)
f. Received cumulative values (sum of received intervals)

5.5.8 Interoperability and Standards

1. The Headend shall be responsible for collecting, storing and presenting all data collected.
2. The Headend shall be the raw data processor for all data to and from the meters.
3. Headend shall be able to support common information model (CIM) structures, multi-speak, and/or service oriented integration patterns for IT systems integration with Meter Data Management System (MDM) and other enterprise IT systems.
4. Headend shall support both electric and gas endpoints
5. Headend shall manage read operations (read, transmit, etc.) of gas meters to enable maximum battery life.
6. The Headend shall provide an open interface that supports multiple MDM systems.
7. Headend shall support standards based integration interfaces: IEE XML, Configurable XML, Configurable CSV, CMEP, LODESTAR, HHF, MDEF, IEE_ ASCII, CIM, Multi-speak, Web services

5.5.9 Manageability

1. Headend software for collecting and processing metering data from field devices shall be separate from software application required to manage network devices. Network management software shall be hosted at the Network Operations Center while software application for managing metering data may be hosted at a different location. Separate network management from data management.
2. All data requests, control commands, configuration commands, and upgrade commands shall be able to be made through the MDM or Headend.
3. Headend shall be capable of collecting, storing, and transmitting all data collected by the meter. This will include register reads and interval reads
4. The Headend shall support time management of meters with multiple clocks. See Section 6.4 “Timing and Clock References”
5. The Headend shall be able to process requests for missing data for both scheduled and on-demand reads.
6. In the event a meter is replaced due to a communication failure, Headend shall be able to remotely restore the proper meter configuration into the new meter.
7. AMI Headend shall have the ability to place meters into groups (regional, rate, schedule, etc.).
8. Headend shall have the ability to place meters into ad-hoc groups for operator analysis.
9. The Headend shall gather and store configurations from network equipment and track changes made to the devices, and to configure, to restore configurations, and to support automated provisioning of new equipment.

10. Headend shall have system administration tools to perform maintenance, monitor system performance, and handle exceptions.
11. The Headend shall provide administrative management and optimization functionality with both user and machine interfaces to support the NOC and network management.
12. The Headend shall provide authorized users with a mechanism to perform queries against the data repository and save the resulting queries for additional analysis. Direct access to tables shall be made available via other systems such as MS Access, SQL, etc.
13. Relevant Xcel personnel shall have direct table access using alternative systems such as, but not limited to MS Access, SQL, etc. to underlying database table structures and all schemas shall be provided.
14. Headend application GUI shall be intuitive and user friendly
15. Headend shall support both scheduled and ad hoc data extract reports for any or all metered values (The report shall be configurable by Company) e.g. kWh, voltage, current, temperature, customer information, etc.
16. AMI Headend shall support managing and administering all aspects of security for various network devices e.g. meters, gas modules, network devices, etc.
17. Headend shall accurately track and manage various network installation stages of endpoints
18. Headend extract reports shall be configurable (e.g. time and date, meter id, etc.)
19. Headend shall support collection, storage and transmission of multiple interval lengths for electric meters (1, 5,15,30,60 minutes)
20. Headend shall support collection, storage and transmission of multiple interval lengths for gas meters (Configurable length for example gas day, max hour, etc.)
21. Headend shall support exception handling and reporting of data during meter time adjustment
22. Headend shall support exception handling and reporting of data during communication failures
23. Headend shall support exception handling and reporting of data during meters errors
24. Headend shall report all statuses associated with Load Profile data
25. Headend shall report all statuses associated with Load Profile data during exception conditions, e.g. loss of network communication
26. Headend shall accurately track and report meter and module program changes. If meter is reprogrammed over the air (OTA), system shall acknowledge with a latency of no more than 20 seconds. Data delivery must be suspended pending user or system action
27. Headend shall support index change for gas modules
28. Headend shall support reuse of gas modules on a different meter
29. Headend shall support process to retain the install index read, pulse value and retain the data in the module itself.
30. Headend shall support tracking of lost module ID’s
31. Headend shall have a mechanism for marrying meters to gas modules that is internally tied for inventory tracking and audits
32. Headend shall track network performance of each end-point
33. Headend shall provide general network performance health reports at a frequency desired by company, hourly, weekly, and daily, etc.
34. Headend shall provide demand reset reports (both success and failure) at a frequency desired by Company e.g. daily, weekly, monthly, etc. Report shall show at a minimum meters that reset (or failed to reset), date and time of reset, date of peak demand, present demand counter, previous demand counter
35. Headend shall provide a menu driven user interface to request all data directly from the meter tables. The data shall be presented in a usable format
36. Headend shall provide menu functionality to manage time zones within the AMI application. This feature would allow time management settings by areas all the way down to the device level.
37. Headend shall support geo coding, and robust visual mapping capability

38. Headend shall offer a meter status management feature, if meters are off line or cannot be reached or system status changes based on user specified parameter. This could more accurately direct auto retries and other reporting/maintenance
39. Headend shall have a real-time dash board display of network device events e.g. failed communication, unreachable devices, network devices, etc. Alert thresholds shall be configurable
40. Identify meters by status i.e. no reading for 2 months. Assign action capability. Auto forward service order
41. Headend users shall have a GUI interface and the capability to manage, change, add, or delete meter records within the AMI application. System users shall have the capability to manage, change, add, and delete meter centric /hardware centric records within the AMI application. (Shall have full AMI on line update capabilities).
42. The demand reset function shall have the capability to be automated by referencing a predetermined billing schedule and initiating auto retry functions if reset attempts fail. User shall also be able to set number of retry parameters. The demand reset function shall also be available via an on demand request. The Headend shall receive confirmation of successful or failed demand reset from the meter(s).
43. Headend shall provide menu functionality to manage historical data (purge) records within the AMI application. This shall include internal tables/log file files / event logs
44. Headend shall provide the functionality to recognize records that are out of synchronization with Company's MDM.
45. Headend shall provide the functionality to manage meters installed but not communicating on the network. Additionally the Headend shall provide functionality to manage meters whose installation is not recorded but are communicating on the network.
46. Headend shall provide the functionality to capture the actual meter program (programmed ID in the meter), and populate this information within the AMI application (so user can reference this information when working with customer/meter information)
47. Headend shall provide the functionality for real-time system reporting and monitoring.
48. Headend shall provide the functionality to identify meter programs within the meter, real time access to this information
49. Headend shall provide the functionality for hardware/device history from both AMI and MDM.

5.5.10 Meter Reading - On Demand

1. On demand meter reads (both human and machine requested) shall be supported. Both successful and failed attempts shall be logged.
2. Headend shall provide specific ANSI table information for data retrieved. For example table 23 for current register reads, table 25 for previous demand, etc.
3. Headend shall provide direct access to meter ANSI tables
4. Headend shall be capable of sending commands directly to the meter in absence of an installed meter status within the Headend while the Meter is in a discovered status.
5. Meter data information retrieved when performing an on request read shall be configurable to include e.g. kwh, kw, date of peak demand, etc.
6. On demand reads shall have the option to be retrieved from either the Headend database or directly from ANSI meter tables.

5.5.11 Meter Reading – Scheduled

1. Headend shall have the capability to manage meter read schedules e.g. flexible parameters based on meter reading requirements (rates, geography, etc.)
2. The Headend shall publish all data collected from meters and made available to the MDM based on user configurable parameters.
3. Headend shall be able to remotely set/update/cancel a meter's read schedule for a specified duration.

4. Headend shall schedule default read times for all unscheduled meters by placing them in a default read group, maintaining balance among the currently scheduled read groups (ensuring system optimization).
5. Headend shall be able to identify those read groups and/or individual meters that consistently fail to meet targeted schedule read times.
6. Headend shall be able to schedule default read times for various groups of meters as initiated by the AMI NOC or user initiated - Menu driven
7. The Headend shall collect load profile data from all meters.
8. Headend shall be able to import Xcel billing schedule. This schedule shall drive meter reading data collections, and automated demand resets
9. Meter reading outputs written to MDM files shall be selectable at the register level/interval channel level. This includes all meter reading registers and interval channels programmed into the meter.
10. User shall have the capability to select menu driven functions when generating ad hoc or scheduled meter reading output files.
11. User shall be able to designate, reads extraction time, billing file create date-time, billing file delivery date-time.
12. AMI Head-End Application shall have an Auto-scheduling feature. Auto scheduling may occur multiple times daily, the time and frequency of the schedule executi0n shall be user configurable.

5.5.12 Outage management

1. Items from section 5.1.13 above shall be supported by Headend.
2. The Headend shall have an auto-retry process after an outage to determine status of electric service.
3. The Headend shall have the ability to process and send power-up messages from all meters to the Headend.
4. Last gasp messages shall be sent by the Headend to the outage management system for processing.
5. Last gasp messages shall be date/time stamped by endpoints. Headend shall include locations to assist in determining the outage area.

5.5.13 Performance - Steady State

The Headend shall gather device usage statistics from network equipment and to track link and system utilization and response times.

5.5.14 Power Quality

Headend shall publish power quality information be subscribed to by other applications.

5.5.15 Reliability

1. Headend shall attempt to recover any information which would have been sent to it from the meter in the absence of a communication failure. This shall include robust interval data gap recovery and events and register data information.
2. Headend shall identify when meters no longer have redundant communication paths available.
3. Headend shall identify exact failure point in the mesh network
4. Headend shall be able to remotely check meters for communications status, energized status, load side voltage and switch status on-demand.
5. Headend shall be able to remotely detect network communications problems including repeated delays in reporting.
6. Headend shall send notice to MDM of failures that would make meters unreachable.
7. Headend shall be able to remotely detect network communications problems including at least diminishing signal strength, loss of redundant communications pathways, etc.

8. Headend shall be able to remotely test communications with customer devices attached to HAN.
9. Headend shall be able to conduct diagnostics for troubleshooting communication problems. This would include network packet tracking, where does the packet fall out, not just hop counter
10. Headend shall have configurable alert levels and notifications based on the severity of a problem detected and the number of endpoints affected.
11. Headend shall be able to classify specific testing/diagnostic results to either require or not require human intervention, test/diagnostic criteria to be configurable.
12. The AMI system shall have redundancies to ensure aggregated system availability of at least 99.999%.
13. Headend shall provide meter diagnostic reports at a frequency desired by Company e.g. real-time, hourly, and daily, etc. The report shall contain the serial number of the meter, all associated time stamped diagnostic events.
14. Headend shall provide a load profile gap report that identifies meters with missing load profile data at a frequency desired by Company, e.g. daily, weekly, etc. The report shall contain the meter serial number, start and stop time of missing data, etc.

5.5.16 Scalability

1. Each Headend instance shall support scalable meter population from 1 million to 10 million.
2. The Headend shall have a distributed architecture that can support redundancy, load balancing and network optimization.

5.5.17 Security

1. Headend shall supply mechanisms which allow for secure device authentication, registration, and revocation.
2. Headend shall supply mechanisms which audit and store all security related events including all access and modifications events within the system.
3. Headend shall supply access control mechanisms (i.e., Identification & Authentication mechanisms) which prevent unauthorized access of information and resource. Example is limiting number of disconnects that can be issued by a single user.
4. The Headend shall be a secure system with strong user authentication processes.
5. Headend shall log all login attempts and support a lockout for a configurable amount of time upon repeated invalid attempts. The login attempt must be reported to the Administrator.
6. The AMI Head-End system should have the ability to integrate with LDAP for authentication (such as Active Directory). The authorization will be managed within the Head-End system.

5.5.18 Storing, Logging and Reporting Events

1. The Headend shall publish all meter events to the MDM
2. Headend shall log successful and failed meter procedures (e.g. Clock reset, demand reset, and reconfiguration, connect/disconnect, etc.). Date and time shall be logged as well.
3. Headend shall have the ability to prioritize messages (functional and non-functional) that are transmitted to the meter (e.g. connect/disconnect, load control, etc.). The priority shall be configurable by Company.
4. Headend shall be able to publish configurable exception events (sag, swell, interruption, fault level, outages, security events, other meter diagnostic events, etc.)
5. The meter logs shall be retrieved regularly as determined by Company.
6. The Headend shall have a configurable alarming system to notify of failure or maintenance requirements. Thresholds shall be configurable
7. Headend shall export a list of failures that would make meters unreachable.
8. Headend shall produce reports that identify system health such that incipient failures can be corrected before they become permanent

9. The Headend shall provide a time stamped event progress log for all commands initiated by the Headend.
10. The Headend shall provide automated email and or text reports configurable by Company.
11. All Headend security logs shall be exported for use by a centralized logging device, such as Security Incident and Event Management (SIEM).

5.5.19 Upgradeability and Configurability

1. Headend shall support a HAN gateway internal or external to the meter.
2. Raw interval data from meters shall be retained for at least 90 days in the Headend. This data can be used for "re-loading" data into batch processes if data is lost or corrupted.
3. Headend shall provide support for disciplined clock in field devices.
4. Headend shall support full meter reprogramming of meters identified from section 2.3 item #5. of the
5. Headend will support use of manufacturer specific software to reprogram meters over the MESH network
6. Headend shall support upgrade of communication module firmware. The application shall report all successes or failures of module firmware upgrades
7. Headend shall support upgrade of meter metrology firmware. The application shall report all successes or failures of metrology firmware upgrades
8. Headend shall support upgrade of meter register firmware. The application shall report all successes or failures of register firmware upgrades

5.5.20 User Interface

1. Headend shall have a real-time dash board display of meter events e.g. sags, swells, harmonics, meter specific events, etc.
2. Headend shall have a real-time dash board display of gas module events
3. Headend shall have a real-time dash board display of network device events e.g. failed communication, unreachable devices, network devices, etc.
4. Headend shall have a real-time dash board display of meter register information
5. Headend shall have a real-time dash board display of demand reset performance
6. Headend shall have a real-time dash board display of ad-hoc reports of meter data, including both registers and profile recordings, individually and aggregated. Such reports must be printable or electronically transmittable for external use (.csv, .xls, html, xml, etc.)
7. Headend shall have a real-time dash board display AMI system performance - overall read performance, failed meters, demand reset statuses, etc. - drill down from system to individual meters
8. Headend shall support role-based security in which access rights can be granted on an incremental basis.

5.6 AMI Headend Non-Functional Requirements

5.6.1 Logging

1. Logging for the AMI Head-End system should be enabled.
2. Any Application, Network, Database, Messaging, User Access, etc. must be managed within the Application and the error must be escalated appropriately. If these errors can be integrated with a Monitoring system (such as HP Operations Manager or similar tool).

5.6.2 Communication

1. The AMI Headend application must support integrations using industry standards similar to CIM and Multi-speak.

5.6.3 Database

The AMI Headend application database must run on Supplier supported versions of SQL Server or Oracle.

5.6.4 Environments

1. The AMI Headend application must have Disaster Recovery capability.
2. The AMI Headend shall be licensed to allow Company to have at least one production environment and two concurrent test environments.

5.6.5 Interface

The AMI Headend application shall provide interfaces to allow for the import, export, and update (synchronization) of information (including meter, premise, and customer information) from the Company's other systems, such as Asset Management, GIS, Meter Data Management, Demand Response, and Customer Information Systems.

5.6.6 Headend Landscape

The Headend application shall support high availability configurations using industry standard tools. Note: Company uses load balancing pairs of servers, and database clusters for the DB. The AMI Headend application should be able to work across server pairs and database clusters.

5.6.7 Logging

1. AMI Headend shall log user activities and include date/time, user id, activity, and success or failure of the activity. The logs shall be searchable by each field and be exportable in a common format, such as xls, csv, or pdf.
2. AMI Headend shall log system activities and include date/time, process id, activity, and success or failure of the activity. The logs shall be searchable by each field and be exportable in a common format, such as xls, csv, or pdf.

5.6.8 Mobile Devices

The system shall enable mobile and/or tablet access to meters for troubleshooting, field access, pinging, etc.

5.6.9 Operating System

1. The AMI Head-End application must operate on all supported releases of Microsoft's desktop operating system.
2. AMI Head-End Application Database must be running on SQL Server 2012 R-2 and or Oracle 11g (Minimum).
3. AMI Head-End Application should be hosted on Microsoft Windows Server 2012 R-2, and/or RHEL version 6.x or greater.

5.6.10 Security

1. The AMI Headend application integration interfaces shall allow the security administrator to generate security reports based on the integration interface's logs.
2. If Supplier has access to any Company or client confidential information, please describe how confidentiality is going to be maintained, including how information is retained and/or disposed of at designated times.
3. The corporate software maintenance process shall be followed for upgrades and patches.
4. Vulnerability scans are to be performed for equipment or product before it is put into both test and production.
5. Product shall not use unsupported open source code or operating systems.

6. Product shall have application security testing performed by Supplier and the results shall be shared with Company.
7. AMI Supplier shall follow best practices in their coding by utilizing secure application development methodologies such as OWASP.
8. All product testing shall be performed in non-production environments.
9. All security logs shall be captured by a centralized logging device, such as Security Incident and Event Management (SIEM).
10. Data encryption shall be utilized for both data-at-rest and data-in-motion.
11. Encryption algorithms shall be of sufficient strength with equivalency of AES-128.
12. Multi-factor authentication shall be utilized.
13. AMI Headend user access shall utilize role-based security, enabling access to be assigned by, for example, functionality, geographic area(s), asset grouping, business areas, etc.
14. Active Directory shall be used for user and service authentication.
15. Credentials are required to be stored in encrypted form.
16. Secure messaging shall be utilized whenever technically feasible such as SFTP.
17. If mobile technology is available, the application shall be compatible with Mobile Device Management Systems.
18. Appropriate firewall rules shall be used.
19. Intrusion prevention technology shall be utilized.
20. Only secure TCP/IP protocols shall be utilized.
21. Least functionality principles shall be practiced.
22. Least Privilege principles shall be practiced.
23. Defense-in-depth posture shall be practiced.
24. Zero-Trust Networking shall be practiced.
25. Tightly-controlled access shall be practiced across all network layers.
26. The AMI Headend shall support 8-character password with complexity (upper and lower case alpha, numeric, special characters).
27. The AMI Headend application shall not need to store Personal Identifiable Information (PII), but if it does, the application shall ensure the security and privacy of such information.
28. A Supplier shall notify Company immediately in writing and electronically when a security vulnerability is identified.
29. A patch shall be released to resolve a firmware or security issue within 30 days of identification of an issue.

5.6.11 Time

1. The AMI Headend application shall be capable of storing and displaying data from multiple time zones.
2. The AMI Headend application shall process Daylight Saving Time switchovers automatically and assure that all functions and programs are updated appropriately. The system shall handle switching to and from daylight saving time without an outage to the system or loss of data. Capability to enable/disable or change the scheduled date and time of automatic switchover of the daylight saving time shall also be provided via graphical user interface.
3. The AMI Headend application shall accommodate daylight saving time switchover such that the missing or extra hour is processed appropriately without manual intervention, including logs, reports, displays, trend graphs, etc.

5.6.12 Reliability

1. The AMI Headend application must support automated data backup, archiving, purging, and restoration. This includes Disaster Recovery.
2. Describe the development languages and architectures the system supports. Include both proprietary and standard languages and architectures: e.g. JEE, SPRING, .NET.

5.6.13 Timed Lockout

The AMI Headend application shall automatically logout a user after a configurable number of minutes of inactivity.

5.6.14 Usability

1. The AMI Headend shall provide functionality to schedule processes to execute.
2. When specifying a periodic execution, it shall be possible to define if the period is based on the start or end of the previous execution.
3. All time-based schedules shall be definable based on absolute or relative time using either standard or application system time scales.
4. The scheduling services shall monitor all schedules to ensure execution at the correct times and notify the users via the Alarm/Events subsystem for any failures or missed schedules, as well as the successful start of a scheduled activity with the reason for activation. The system shall also support the ability to log these events to the Central Logging system as well as notify IT Support personnel about these application scheduling failures via e-mail or text message.
5. All AMI Headend parameters for configuration, performance tuning, and variants shall be defined without having to modify any source code.
6. The AMI Headend shall incorporate displays/forms to manage the configuration parameters. These displays/forms shall be easy to understand and navigate. The system configuration parameters shall be clearly and concisely documented.
7. The AMI Headend shall provide report services that are available for use from any application and server. The AMI Headend shall support routing reports to a report repository, Email or printer. A report repository may be configured for easy user access to reports as well as time based report deletion.

5.6.15 User Lockout

The AMI Headend application shall lock out a User account after a configurable number of consecutive failed login attempts, and provide an administrator function to unlock accounts.

5.6.16 Users

The system shall support up to 1000 users, with up to 500 concurrent users with direct access to meters ; e.g., field, meter shop, meter analyst, call center, billing.

5.7 Requirements for Voltage Phase Identification

5.7.1 Description

Company wishes to consider applying a form of Distribution Automation “Intelligence” using its network of connected meters. Company invites Suppliers to submit an optional technical and price proposal for a system that may be attached or included in the WMN that provides a means to identify phase information, hereafter referred to as the Voltage Phase Identification System.

5.7.2 Requirements

The Voltage Phase Identification system shall consist of a hardware/software and any applications that uses any form of computational and/or WMN networking technologies that have the means to detect and identify phase information for any metered attachment and to transmit the information to a Headend attached application server for subsequent use in DA control and monitoring applications.

5.7.3 Response Methodology

1. Suppliers shall submit a proposal responding to the Description and considering the Requirements listed (above). The response shall include the following components:

a. Description of the offering including narrative and equipment block diagram identifying hardware and software components and their interconnection.
b. Description of the proposed scientific principles by which the phase information will be obtained.
c. The guaranteed accuracy of the information that is presented to the Headend and downstream application.
d. Description of any special features and or requirements that are necessary to be included or provisioned in the meters that are participating in the Voltage Phase Identification System.
e. List of meters types (manufacturer, make and model) including NIC types supported.
f. Description of the methods and procedures that are required to physically and electrically attach any devices to customer or Company owned property or equipment
g. Description of the Back Office IT equipment that is necessary to implement to support the Voltage Phase Identification system.
h. Tabulation of the industry standard(s) applied and used.
i. Speed at which the application reports data to the end user application.
j. The method by which Company will set-up and monitor the performance of the application.
k. The method and protocols by which Company will interact with the resulting data.
l. A definition and description of the communication protocols used between the Headend and the application server, if used.
m. The software language protocols used between the meters and application for inter-device communications.
n. Description of other requirements that Company must fulfil so as to achieve a wholly working system that is integrated into a fully operational IT environment.
o. A description of the security protocols applied and the manner in which security protocols can be upgraded or added to.
p. Description of the methods by which any firmware or software can be upgraded.
q. Description of the impact of adding Phase Identification to the AMI network proposed herein in terms of offered traffic and prioritization requirements in forward and reverse directions
r. Per unit costs for equipment to be located on all consumer premises (~1.4 M). Price for valid meter types per item (e) above.
s. Cost for Back Office equipment as required to operate the system.
t. Cost for annual support agreement for deploying to all consumer premises in a two-year period.

5.8 Requirements for Home Area Networking

5.8.1 Description

Company anticipates that either through its own or third party offered programs and services, customers may require access to their individual meter data in greater granularity and frequency (near real-time) than may be practical to backhaul over the AMI network and store at the Xcel owned/operated Headend on a routine basis. One mechanism for obtaining this type of granular data is for the customer meter to interface directly with the customer's HAN or similar enabling technology. This Section seeks responses and proposals from Suppliers to demonstrate how their AMI solution can meet these anticipated use cases.

5.8.2 Response Methodology

Suppliers shall submit a proposal responding to the general description (above) and considering the "Requirements for HAN" listed below. The response shall include the following components:

1. Description of the offering including narrative and equipment block diagram.
2. Description of the proposed customer facing interface and the methods by which customers interact with the information.
3. Description of the methods and procedures that are required to physically and electrically attach any devices to customer or Company owned property or equipment
4. Description of the Back Office IT equipment that is necessary to implement
5. Tabulation of the energy related information that is expected to be available to the customer.
6. Tabulation of the industry standard(s) applied and used.
7. Expected accuracy, precision and currency (or timeliness) of the information that is presented to the customer.
8. Description of the methods by which information that is available to the customer is synchronized to the information that is transferred and available to Company.
9. Response to the Requirements set out here (below).
    a. Description of the installation methodology required.
    b. Description of the proposed method by which the customers will gain/access customer care support.
    c. Description by which any firmware or software can be upgraded.
    d. Description of the impact of adding HAN to the AMI network proposed herein in terms of offered traffic and prioritization requirements in forward and reverse directions.
    e. Per unit costs for equipment to be located on consumer premises in quantity of 10,000, 60,000 and 70,000 for the first, second and third year respectively.
    f. Cost for Back Office equipment as required for system operation.
    g. Cost for annual support agreement to accompany item “e” above.
10. Supplier shall be expected to participate with the Company in industry research or demonstration projects that seek to enhance understanding or capabilities of the AMI system to meet Company goals.

5.8.3 HAN Interface Requirements

1. The Supplier shall document types of interfaces and data types supported to be consistent with the proposed solution. .
2. Supplier shall describe how their system shall meet the HAN Requirements specified above.

5.8.4 HAN Data requirements

1. Through the HAN interface, the customer facing HAN device must be provided with metering data such present energy consumption (current kwh consumption rate), present demand(present KW), peak demand (peak KW), real-time voltage ,etc.) at a highly granular rate. Retrieved or pushed data, shall be updated at a highly granular rate, for example, for meters configured to measure demand over a block 15 minutes interval, retrieved demand data shall be in real-time even in instances where the demand interval has not elapsed. Similar requirements shall apply to load profile data, voltage, etc.
2. Through Company back office IT and web-portal, provide customers with metering data such present energy consumption (current kwh consumption rate), present demand (present kW), peak demand (peak kw), real-time voltage, etc.) at a highly granular rate. Retrieved or pushed data, shall be updated at highly granular rate, for example, for a meter configured to measure demand over a block 15 minutes interval, retrieved demand data shall be in real-time even in instances where the demand interval has not elapsed. Similar requirements shall apply to load profile data, voltage, etc.

5.8.5 Availability

The HAN interface shall be available as an optional feature on meter hardware provided for the AMI solution. Company estimates ~10% of customers (~140,000) will desire this functionality and therefore the HAN interface should be available as an option for these customers.

5.8.6 HAN Interface Security

1. The Supplier must demonstrate that the HAN interface can withstand security testing requirements (ex. PEN testing) to insure the HAN interface does not create an unprotected entry point to the AMI network.
2. Supplier's HAN interface must maintain customer's data privacy by preventing unauthorized access to the meter data.
3. Supplier must demonstrate how their solution allows customer's HAN access to the data through a registration process or other means. This process should account for what happens when the customer moves in/out of a premise. Supplier should also address how data is encrypted.

5.9 Requirements for Gas Modules

5.9.1 Meter reading-Schedule

1. AMI Gas Modules shall be configurable to provide hourly interval data.
2. System shall report gas usage daily

5.9.2 Data availability

1. AMI modules shall be capable of storing at a minimum 60 days' worth of 1hr intervals in non-volatile memory.
2. AMI modules for meters attached to correcting instruments shall report all available data from the instruments e.g. usage, time, pressure, temperature, etc. Adapt to legacy communicating devices (metscans, Metretek, Mercury correcting instruments, Reynolds, etc.)
3. AMI modules and associated AMI system shall report customer peak usage, date and time each billing period based on tariff.
4. Where aggregate billing is required, associated AMI modules shall be time synchronized to 15 minutes to support aggregate billing.
5. AMI modules shall capture start and stop time and volume of gas consumed during curtailment period.
6. AMI modules shall provide battery end-of-life alarms no less than 6 months before end of life.
7. AMI system shall provide report on remaining useful life of batteries

5.9.3 Meter Configurability

1. AMI modules that shall provide temperature compensated and uncorrected index reads (dials) for meters without correcting instruments.
2. Interval data from gas meters (such as transport or interruptible class customer) shall be time stamped.

5.9.4 Storing, logging, and reporting events or Outage Management

AMI modules shall provide notification and acknowledgement of curtailment events

5.9.5 Meter reading-real time

Gas module time related measurements shall be within 60 seconds of actual time.

5.9.6 Installation and Maintenance

AMI modules shall be compatible to all the existing Company gas meter population

1. If modules have a mechanical interface to the meter, then AMI device shall not place more than 1 inch ounce of mechanical torque on meter drive else if an electronic interface, then modules shall be compatible with pulse outputs of existing meters and instruments.
2. AMI modules shall be suitable for both outdoor and indoor installations.
3. Modules must be capable of communicating from meter rooms, basements, etc.
4. AMI modules shall be field replaceable.
5. AMI modules shall preserve the integrity of device configuration and data during battery exchanges
6. AMI module and field tools must have mechanisms that preserve data and configuration from one module to another during a module exchange
7. AMI module shall not exert torque in excess of 1 inch oz or meter manufacturer specifications whichever is less and shall not cause gas leakage.

5.9.7 Tamper/Theft detection

The AMI module shall report any logged errors within the module.

5.9.8 Upgradeability and Configurability

1. AMI modules shall support 4, 5, 6 and 7 dial indexes.
2. AMI modules shall be field configurable to accommodate meters with different drive rates including; 1, 2, 5, 10, 50, 100, 500 and 1000 foot drive rates.
3. AMI modules attached to electronic instruments, indexes or meters shall collect and transmit any errors logged locally by the instrument
4. AMI modules shall maintain an audit trail of changes to configuration and information shall be made available to back-end systems

5.9.9 Tamper/Theft detection

AMI modules shall be equipped with tamper detect mechanisms e.g. module removal, module dis-assembly, magnetic interference, etc.

5.9.10 Storing, logging, and reporting events

AMI modules and associated Headend system shall have mechanisms for detecting usage anomalies (e.g. Excessive or zero usage)

5.9.11 Reliability

Meter manufacturer's index read shall remain functional through any AMI module failure

5.9.12 Interoperability and standards

1. AMI modules shall be in compliance with ANSI B 109.
2. AMI modules shall be in compliance with class I division 2 group D of the National Electrical Code (NEC)

5.9.13 Meter reading- on demand

AMI modules shall be field readable via a field device without requirement for a direct connection. The field device shall have provisions for waking up the module for immediate communication to the field device.

5.9.14 Power quality

1. Batteries must perform in a predictable and environmentally acceptable manner. Expected battery life of no less than 20 years.

2. AMI module battery gas Leakage shall be self-contained - no out gassing of toxic/corrosive materials and no exothermic reactions
3. AMI modules shall furnish own power requirements

5.9.15 Reliability

Gas modules must be capable of bi-directional communication directly to network without intermediate devices. Communicate to AMI network in absence of electric meters - gas only deployment

5.9.16 Security

AMI modules shall preserve data and customer privacy per NIST SGIP security requirements

5.9.17 Upgradeability and Configurability

1. AMI module must be capable of supporting pulse and / or mechanical interfaces. Support all available gas meter products in marketplace
2. AMI modules and associated systems shall support local and remote configuration of modules and / or configuration of correcting instruments
3. AMI modules shall provide details of its current configuration e.g. Meter dials, drive rate, value of right most digit, tamper detect, etc.

5.10 Requirements for Gas ERT modules

5.10.1 Description

Company has in service a quantity of Itron 100G ERT gas modules. The modules are diversely located within the PSCo service territories and, notably, are also in use in service territory that serves gas only – i.e. no electric AMI services.

A database of endpoint devices is attached to this RFP indicating the location of the 100G ERT modules under the name of Final – PSCo 100G ERT Modules. Zip

5.10.2 Requirements for Reading Itron 100G ERT Modules

Suppliers are required to submit innovative technical/price proposals to address the general problem of finding an economically viable and practical solution to reading the modules (meters) in a modern AMI environment: Proposals of the following nature are invited:

1. A technical/business solution that reads the Itron 100G ert meter modules in all service territories without changing the ERT module.

5.10.3 Response Methodology

Suppliers shall submit a proposal responding to the general description (above) and considering the “Requirements for Reading Itron 100G ert Modules” listed above. The response shall include the following components:

1. Descriptive response to the Requirements set out here (above) including any required narrative and equipment block diagrams.
2. Description of the methods and procedures that are required to physical and electrically attach any devices Description of the Back Office IT equipment that is necessary to implement
3. to customer or Company owned property or equipment
4. Description of the proposed customer facing interface and the methods by which customers interact with the information.
5. Tabulation of the energy related information that is expected to be available to the customer.
6. Tabulation of the industry standard(s) applied and used.

7. Expected accuracy and precision of the information that is presented to the customer.
8. Description of the methods by which information that is available to the customer is synchronized to the information that is transferred and available to Company.
9. Description of the installation methodology required
10. Description of the proposed method by which the customers will gain/access customer care support
11. Description by which any firmware or software can be upgraded.
12. Description of the impact, if any, of adding this gas related data traffic to the AMI network proposed herein in terms of offered traffic and prioritization requirements in forward and reverse directions
13. Per unit costs for equipment to be located on consumer premises in quantity of 103,400 annually for a period of 5 years totaling 517,223 ERT modules.
14. Cost for resilient Back Office equipment as required for system operation.
15. Cost for annual support agreement to accompany items # 13 above.

5.11 Requirements for Electric Pre-pay Services

5.11.1 Description

The Company anticipates that either through its own or third party offered programs and services, customers may desire to use Pre-pay services in the form of network connected AMI meters. The Company considers Pre-pay services as a technology option arising from the use of AMI. Company will consider its application as a customer option.

This section seeks responses and proposals from Suppliers to demonstrate how their AMI solution can meet these anticipated use cases.

5.11.2 Response Methodology

Suppliers shall submit a proposal responding to the general description (above) and considering the requirements and queries itemized below. The response shall include the following components:

1. Item by item written response to the Requirements set out here in Section 5.11.3
2. Item by item written response to the Queries set out here in Section 5.11.4
3. Pricing for Pre-pay Meter option per “meter options” on Xcel Energy AMI RFP pricing Template v4.xlsx
4. Pricing for Pre-pay Back Office software and any other costs attributable to Pre-pay option to be provided on Xcel Energy AMI RFP pricing Template v4.xlsx

5.11.3 Electric Pre-pay Requirements

1. The Supplier’s Pre-pay solution shall consist of a network integrated solution that operates by way of AMI meters and one or more applications operating within the Headend and through its interfaces to external components.
2. All measurements, including but not limited to, voltage, current, tamper, outage, etc. as defined in Sections 5.1, 5.3 and 5.4 shall apply.
3. Pre-pay shall be offered in a form that it is configured as a firmware or software option to the base meter.
4. The meter service switch shall be operable with or without Pre-pay credit.
5. The Pre-pay solution shall be end-to-end compliant to Company Security principles, strategy and Requirements per Section 2.4.
6. Any interface used to enable Pre-pay option shall maintain customer’s data privacy by preventing unauthorized access to the meter data.

5.11.4 Queries Concerning Electric Pre-pay Option

Suppliers are required to respond to the following information requests, provide:

AMI Meter Requirements

1. General

    a. A general description of the offering including narrative and any figurative descriptions that are necessary to describe the hardware and software components that are necessary and the manner in which Electric Pre-pay services are enabled/configured and may be offered to customers.
    b. A description of the Supplier's Pre-pay option defining the offered feature set, and product performance specifications.
    c. Information concerning deployment at other utilities utilizing Pre-pay system described in item 1 above; including customer contact name and address, scope of the project and the year of deployment.
    d. A description of the methods and procedures that are required to physically and electrically attach any devices to customer or Company owned property or equipment.

2. Security

    a. A description of the technologies applied and the means by which physical and cyber security is enabled.
    b. A statement indicating areas where security defenses differ and/or are unique from the Baseline Electric Metering Systems as defined in this RFP.
    c. A statement indicating any known security related vulnerabilities or concerns.
    d. A description of the means by which the Pre-pay system can withstand security testing requirements (ex. PEN testing) to insure the interface does not create an unprotected entry point to the AMI network.

3. Impact on Existing Systems and Network

    a. A description of the impact of Pre-pay services on the network in terms of traffic flow volumes, network performance requirements and the required network availability specifications.
    b. A statement indicating the industry standards and protocols applied to the solution including, but not limited to:
    c. Transport and application layer protocols used between meters and the Headend
    d. Transport and application layer protocols used between the Headend and any other platforms
    e. Protocols applied for enablement of secure services
    f. Operating systems and languages
    g. Customer Facing Functionality
    h. A description of procedures, methods, requirements for establishing and terminating the service or migrating in the event of Company or customer initiated changes. This process should account for what happens when the customer moves in/out of a premise.
    i. A description of options available to customers for purchases for prepayment such as; vending kiosks, cell phone applications, telephone, and internet.
    j. If vending kiosks are part of the system, provide descriptions to include specifications, operations and maintenance details
    k. Description of any proposed cards or tokens, etc. that are required or desired to be used in conjunction to the service offering.
    l. A description of the customer options for viewing/monitoring status of their Pre-pay account including, but not limited to:
        i. display or on-line, for example
        ii. rate of usage
        iii. balance remaining
        iv. Estimated time remaining
        v. Status / error codes

vi. Time/date
vii. Tariff
viii. Other information available (describe).

m. A description of the customer configuration and settings options that are available to customers for self-management of their account.
n. A statement indicating the expected accuracy, timeliness and precision of the information that is presented to the customer.

4. Application Functionality

a. A description of the locally or remotely configurable parameters, including:
   I. Time based rates
   II. Credit forgiveness, on non-disconnecting periods. For example, service switch is configurable to not operate if meter goes into arears during Company defined holidays, defined overnight hours, defined season, etc.
   III. Enabling the meter to continue service into a defined credit amount
   IV. Energy pricing, taxes, other tariff cost adders, etc.
b. Descriptions of software configuration features including but not limited to:
   I. the means by which Company can establish and make adjustments to prepayment plans.
   II. the means by which pricing is updated and customers are informed of the pricing status.
   III. The means by which any firmware or software can be upgraded.
   IV. the means and speed by which a tariff is applied and the manner in which Company and the customer are informed that the tariff is in effect. Description of the proposed method by which the customers will gain/access customer care support.
   V. Any other configuration features available from Supplier to Company when applying the Pre-pay option
c. A description of the Back Office IT equipment that is necessary to implement the service.
d. A description of the methods by which information that is available to the customer is synchronized to the information that is transferred and available to Company.

6 Network Requirements

6.1 General Networking Requirements

6.1.1 Management Network & Device Configuration

1. The Supplier must clearly state the Networking Strategy for implementing 1.4 Million Devices on the field with an IPv6 Addressing spacing, able to successfully transmit the data while many other legacy devices (in substations, and corporate areas) are on IPv4.
2. Supplier shall provide a network management system (NMS) that is capable of managing and monitoring all aspects of the communications devices on the systems. This includes, but is not limited to; IP addressing, software/firmware updates, current operational status, historical operational status, performance, RF characteristics/link budget.
3. Supplier's network management system (NMS) shall be provided for installation inside of Company's private IT environment, to be managed and operated by Company.
4. Supplier's network management system (NMS) shall operate in a virtualized server environment.
5. Supplier's network management system (NMS) shall be wholly redundant with installations in separate physical locations with the ability to automatically failover operation from one installation to the other.
6. Supplier's solution shall provide real-time reporting of events and alarms.
7. Supplier's solution shall support reporting and alarming based on configurable thresholds set for specific criteria. For example, alarming for a node whose link performance falls below threshold.
8. Supplier's solution shall utilize a standardized method for reporting events and alarms, including support for SNMP up to and including version 3.
9. Supplier's network management system (NMS) shall provide an API and/or north bound interface in order to integrate with Company's network operations center (HP OpenView and Network Node Manager).
10. Supplier's solution shall provide Over-The-Air firmware and software upgrades to communications devices utilizing the communications network.
11. Supplier's solution shall maintain two working copies of the operating software on board the device and a mechanism to enable rapid fallback to the redundant OS.
12. Supplier's solution shall support automatic provisioning.
13. Access to the network management system (NMS) shall be secured through configurable user roles and permissions and accessible via secure protocols such as SSH or HTTPS.
14. Supplier’s network management system (NMS) shall support the use of external and centralized Access, authorization, and accounting (AAA) through an integration with Active Directory or similar technology.

6.1.2 Network Design

1. In areas where the Company serves both electric and gas, the network shall be designated to support both electric and gas metering.
2. In areas where the Company serves gas exclusively, the network shall be designated to support gas metering.
3. Every node in the Wi-SUN system shall be able to communicate to multiple border router nodes with diverse WAN connections (e.g., connection to different WiMAX base stations).
4. Purposed network design shall provide sufficient battery backed Wi-SUN nodes such that any device on the network can be reached in the case of power failure.
5. The network must be designed to support communications to all devices in the attachments “Electric Distribution Points” and “Gas Distribution Points”.
6. The network must be designed to support the performance criteria listed in Table 8 below.
7. The maximum number of hops from border router node to any Distribution Automation (DA) node shall not exceed 3.

8. The maximum number of hops from border router node to any meter node shall not exceed 5.
9. In the event of access point loss, the system shall be capable of automatically re-routing all affected meters through alternate access points such that they are reachable from the head-end within one hour.
10. Supplier shall quote sufficient spare infrastructure to support the solution in an operation (non-deployment) environment.

Table 8 – Performance Requirement by Traffic Type

		Round-Trip			
Traffic Type	**Minimum Bandwidth**	**Maximum Total Network Latency**	**Maximum Wi-SUN Network Latency**	**Total Jitter**	**Packet Loss**
Fast DA	300 kbps	300ms	100ms	20ms	< 1%
Normal DA	300 kbps	500ms	300ms	20ms	< 2%
Sensors	10 kbps	1000ms	800ms	100ms	< 3%
AMI	10 kbps	2000ms	1800ms	100ms	< 4%
Management	B.E.	B.E.	B.E.	100ms	< 5%

6.1.3 Physical & Environmental

1. All communications devices shall have sufficient solid state, non-volatile storage to accommodate ten (10) full copies of the operating firmware and software.
2. Supplier shall indicate the quantity of volatile memory available on the network interface card (NIC).
3. Supplier's solution shall utilize an ARM7 or equivalent at a minimum.
4. Supplier's network interface card (NIC) shall utilize an industry supported operating system. Supplier to indicate the operating system and version.
5. All non-meter communications devices in the Wi-SUN mesh shall provide sufficient battery backup to remain operational for no less than 8 hours in all environmental conditions (Item 10).
6. All battery devices in the network shall employ an automatic battery load self-test to operate on a set interval and provide alarms in the event a battery is performing outside of specification and be connected to the network management system for presentation/coordination of the alarm(s).
7. All Wi-SUN infrastructure (border router nodes and relay nodes) shall operate from mains AC voltage between 100 and 240VAC.
8. Any Wi-SUN end-point node used for Distribution Automation shall operate from 12VDC and/or 24VDC.
9. Supplier shall provide datasheets for each piece of equipment in the solution that provides the following, at a minimum:
    a. Physical Dimensions & Weight
    b. Operating Temperature/Conditions
    c. Physical Interfaces (power, I/O, etc.) and how they are physically secured.

d. Picture(s)
e. RF Characteristics
f. Power Supply
g. Necessary cables and connectors
h. Communications Interfaces and protocols
i. Methods of powering form AC mains
j. Methods of providing grounding for human safety
k. Methods of providing grounding for equipment protection
l. Methods of providing electrical protection for electrical transients
m. Methods of providing protection for lightning

10. Devices intended for outdoor mounting should operate in temperatures between -30F and 120F at altitudes up to 11,000 ft. AMSL.
11. Supplier's solution shall include a small form-factor Wi-SUN (endpoint) node for general interface and control applications. The small form factor node shall:
    a. be compliant to Wi-SUN protocols
    b. be capable of participation in the wireless mesh as a non-repeating endpoint or as a repeating device with endpoint functionality.
    c. be fitted with no less than one Ethernet IEEE802.1Q interface on RJ-45 port to connect to an IPv4 or IPv6 device.
    d. Include routing and QoS functionality that is required to enable Requirements set out in Section 6.1.5
    e. be physically smaller than 6in x 6in x 4in.
    f. include an RS-232 capable DB-9 port.
    g. Include a management interface using the Wi-SUN NMS infrastructure
    h. be designed using no-corrosive components for use in outdoor unheated cabinets
    i. be inclusive of AC and DC powering options having surge and lightning protection
    j. be offered in an configuration that facilitates standardized mounting in outdoor NEMA rated cabinets.

6.1.4 Standards & Interoperability

1. Supplier shall participate in the Wi-SUN Alliance as a Promoter or Member Company.
2. Supplier's solution shall be certified for Wi-SUN interoperability to all layers currently published by the Wi-SUN alliance at the time of response submission of this Request for Proposal.
3. Supplier shall provide documentation showing Wi-SUN certification for any devices submitted as part of the Wireless Mesh Networking solution.
4. Suppliers shall also fill-out "FAN-Profile-Implementation-Poll-Template 0v02 Xcel Energy.xlsx"
5. Supplier's solution shall be Over-The-Air Upgradable to a fully-compliant Wi-SUN protocol stack.
6. Supplier will provide a fully-compliant Wi-SUN firmware and/or software package for Over-The-Air deployment to all devices within twelve (12) months of the ratification of the full Wi-SUN protocol stack by the Wi-SUN Alliance.
7. Supplier shall allow Company to test their solution against other Wi-SUN equipment (including other Suppliers or test kits, such as EPRI's Wi-SUN tool) in order for Company to satisfy itself of the solution's interoperability.
8. All supplied equipment shall be FCC regulatory compliant in all aspects as related to no less than in and out-of-band RF emissions, power level, interference mitigation technologies, band filtering and health and safety.

6.1.5 Technology

1. Security is core and critical to the success of AMI and the mesh network. Provide an overview and detailed description of how the solution is secured, what components are needed to create the necessary security, and how the entire security solution is managed.

2. The solution must be an IPv6 network based on IEEE 802.15.4g using IEEE 802.15.4e
3. For each radio type supplied, Supplier shall state the radio RF performance parameters in the form of a table that is ordered by frequency band, modulation type and error correction scheme and that tabulates no less than the following guaranteed values:
    a. Maximum Transmitter output power
    b. Transmitter Error Vector Magnitude (EVM) for 100% FCC rated power, taken as the average power of the constellation error vector as a ratio of the constellation average power.
    c. Occupied bandwidth, quantified as bandwidth in Hertz, while under full modulated operating conditions where the emission relative magnitudes levels are 3db, 20db and 40 dB less than occupied necessary power magnitude.
    d. Receiver sensitivity as signal level, given in decibels above a mill watt, that is required at the 50 Ohm antenna connector, that is required to achieve a bit error rate of 1 error in 100,000 bits sent.
    e. Receiver Selectivity, measured as a ratio of the interfering power outside of the desired channel but within the authorized operating band, to that of the desired signal, for the condition in that causes a 10% reduction in received BER relative to the non-interfering case.
    f. Receiver blocking, measured as a ratio of the interfering power outside of the desired channel and outside of the authorized operating band, to that of the desired signal, for the condition in that causes a 10% reduction in received BER relative to the non-interfering case.
4. For each radio type offered, Suppliers shall provide a block diagram of the transmission/reception chain design and radio the front end filter characteristics indicating no less than the 3 dB bandwidth of the radio front end and the availability of any dynamic selectivity options.
5. For each radio type offered, Suppliers shall provide the following information:
    a. The manufacturer and part number of the semiconductors used to implement the radio
    b. The manufacturer and part number of the semiconductors used to implement the device controller
    c. The operating systems used including version deployed
6. The system shall allow for users to statically determine primary and secondary routes for certain nodes.
7. All Wi-SUN Border Router Nodes shall be able to transport all forms of traffic, including AMI and Distribution Automation.
8. Supplier's solution shall support carrying IPv4 traffic over the Wi-SUN network.
9. The network shall support DiffServ/DSCP as a standardized method for managing and Quality of Service and marking, queueing, and priority forwarding. DSCP marking is a requirement at Wi-SUN nodes where the node is used for control applications.
10. The network shall support adding 802.1Q VLAN tags at the point traffic enters the network.
11. The Wi-SUN border router, at its Ethernet wired side, shall support:
    a. IEEE 802.1Q
    b. Dual Stack
    c. Mapping of QoS and COS tags between IETF layers 2 and 3
    d. Routing protocols including but not limited to OSPFv2, RIP2 and BGP4
12. Devices in the network shall not re-mark any QoS information for any traffic without being explicitly told to do so.
13. Supplier's solution shall provide no less than 6 levels of prioritization for Quality of Service Management.
14. Any Wi-SUN nodes that participate in the network in a repeating mode shall only repeat data traffic that belongs to the Company and is a member of its assigned cluster.
15. Wi-SUN nodes shall be configurable to participate in the Wi-SUN mesh as Router Nodes or Leaf Nodes.

Network Requirements

16. Any node in the network shall be capable of running applications or scripts locally on the device, utilizing the network interface card for wireless communication
17. Supplier shall provide a Software Development Kit (SDK) for their network interface card to support the development of applications and scripts to operate on the device.
18. Applications or scripts deployed to the device may be written by any party, including Company, the Supplier, or a third party.
19. The Wi-SUN network management system shall support over-the-air deployment of applications or scripts to the network interface card in any device on the network.
20. Network traffic shall not be required to route through the Headend or any other application. For example, the SCADA system shall be able to directly communicate with a distribution automation device on the Wi-SUN mesh without routing through or utilizing an intermediary application.
21. Node-to-Node one-way latency shall not exceed 50ms.
22. The hop-by-hop performance must meet the requirements detailed in Table 9 below.
23. Supplier's solution shall support all Wi-SUN defined data rates, including 50kbps, 100kbps, 150kbps, and 300kbps.
24. Supplier's solution shall support data rates in excess of 1 Mbps.
25. Supplier's solution shall support Forward Error Correction (FEC)
26. Supplier's solution shall support Orthogonal Frequency-Division Multiplexing (OFDM).
27. Supplier's solution shall support North and South America frequency band (902-928 MHz) in conformance with [FCC-Part-15.247]
28. Supplier's solution shall support TCP.
29. Software and Firmware updates to any single node in the network shall complete within 10 minutes.
30. Supplier shall participate in 3rd party security and network penetration testing through public security events or engagement with security Suppliers. Supplier shall elaborate on their engagement in this category.
31. Supplier's solution shall include a network interface card (NIC) that is embeddable in other Supplier's products. This includes integrating the embedded NIC with device including, but not limited to Street Light photo controls, Capacitor Banks, Reclosers, Voltage Regulators, and Fault Location Devices. Suppliers shall provide a list of products for which their NIC is already embedded.
32. Every node-to-node connection shall be encrypted.
33. Any IPv4 traffic coming off of the Wi-SUN Border Router Node shall be routable on the WAN at the physical interface.
34. Wi-SUN nodes shall support the following security features;
    a. Embedded Firewall
    b. MAC Locking
    c. IPSec
    d. Port Rules
    e. IP Rules
35. Supplier's solution shall support direct device-to-device communication over the Wi-SUN mesh without needing to traverse a border router node; including both IPv4 and IPv6 devices.
36. System shall include a user-friendly field configuration tool (e.g., web-based) that can interact with field devices through the mesh network itself.
37. Supplier's solution shall be able to transport jumbo frames.
38. Any IPv4 traffic generated by a node on the Wi-SUN network shall be routable as native IPv4 traffic at the WAN interface of the border router. Supplier shall detail how this is accomplished (tunnels, translation, dual-stack, etc.).
39. Access to any devices on the network shall be managed through defined users and configurable roles with varying levels of permissions.
40. Access, authorization, and accounting (AAA) for any device on the network shall support integration with Active Directory or similar technology.

Table 9 – Performance Requirement by Hop Count

Hop Count	Total One-Way Latency	Total Round Trip Latency	Total Jitter	Packet Loss
1	50ms	100ms	10ms	< 1%
2	100ms	200ms	20ms	< 2%
3	150ms	300ms	30ms	< 3%
4	200ms	400ms	40ms	< 4%
5	250ms	500ms	50ms	< 5%

6.2 WiMAX Gateway Requirements

6.2.1 Description

Company requires the Supplier to provide a quantity of environmentally sound enclosures to house communications electronics equipment and battery(s) for vertical or horizontal pole mounting in a power utility application. The arrangement is configured in a single enclosure however it may require two enclosures to accommodate suitable batteries and mounting standards. The required enclosure forms the basis for interconnecting and powering the required equipment.

The enclosures are necessary to conveniently package and integrate the Wi-SUN border router with the WiMAX self-contained CPE unit. The CPE unit contains a directional antenna and integrated electronics unit. It requires powering by way of battery backed-up PoE.

Company preference is to secure a solution that is tightly integrated to the Supplier's equipment from a packaging perspective. Size is important (~ 6" x 8" x 10") or smaller. The requirement develops product that is easy to install without aid of large equipment or extensive field crews.

6.2.2 Requirements for the Enclosure

1. Company Preferences:
    a. a single battery/charging arrangement for both radios.
    b. Size; (~ 6 x 8 x 10) inches
2. The arrangement shall accommodate no less than two radios:
    - One radio (for wireless mesh applications) is expected to be contained in the enclosure and having an antenna connector on the outside of the enclosure.
    - The other radio is for microwave applications (WiMAX); it is a self-contained unit about 10" square and 3" thick and will be mounted some distance from the enclosure. This radio unit will be interconnected with the "inside" radio by way of PoE Ethernet.
    - The inside Wi-SUN radio consists of the Supplier's provided device.
    - The outside radio is manufactured by AirSpan Inc. It is usually called: WiMAX CPE. The radio/antenna are integrated and operated through an Ethernet PoE interface.
3. Batteries shall be manufactured using a technology that has long service life and high energy density. Suppliers shall state the technology used, manufacturer and part number(s) proposed.

4. Battery backup protection shall be provided for 8 hours of service in the event of power failure. The WiMAX radio is expected to use 24W peak power and 13 Watts of power continuously however, Suppliers are required to confirm the power requirements by their own means.
5. An integrated system of battery performance, maintenance and management is a requirement for all included components including the WiMAX CPE.
6. The system shall be fitted up with 115v AC powering that is suitable for outdoor interconnection to pole or underground connection arrangements and shall include a positive disconnect arrangement for field service safety.
7. The enclosures shall be fitted up in such a way as to be secure against tampering and include a system of intrusion alarms that are integrated to the Suppliers network management environment.
8. All units shall be fitted up with high quality environmentally appropriate weatherproofing, lightning, grounding, surge and security protection.
9. The enclosures shall be labelled with weather resistant bar-codes that are compliant to the Suppliers Inventory management system as applied to Company
10. Mounting arrangements shall accommodate vertical mounting on utility poles and horizontal arms.
11. Company requires that the completed WiMAX gateway be designed for long term outdoor utility service and that it be mocked-up and extensively tested, trialed, prior to be placed into service.

6.2.3 Response Methodology

Response Proposals shall take the following form:

a. Itemized price proposal for 100, 1000, 5000 and 10000 units.
b. Description of the product development cycle including development of prototypes, testing program, and delivery schedules.
c. Description of the offering including narrative and equipment block diagram.
d. Wiring diagram showing interconnection of components.
e. Description of lightning and grounding protection
f. Dimensioned sketch of the equipment.
g. Environmental specifications.
h. Description of the methods used to weatherproof the equipment.
i. Physical specifications and mounting configuration.
j. Description by which any firmware or software can be upgraded.
k. Battery performance specification including: lifetime, technology, temperature specifications
l. Battery monitoring technology methodology (SNMP, etc.)
m. Performance guarantees and warranty commitment
n. Description of security methods applied to the physical and electrical/communications components
o. Description of the methods by which Company can manage inventory control
p. Description of the methods by which Company interacts with the user interface

6.3 Use of IP-VPN's

Where any IP-VPN used over the public Internet for service, support and or maintenance, it shall be:

a. equipped and configured to interface to Xcel's existing standard based IPSEC infrastructure, presently Xcel uses Cisco IPSEC based IP VPNs;
b. approved for use by Company;
c. Operated in a manner that is compliant with the Company security policy; and subject to periodic security assessment audits by Company.

6.4 Timing and Clock References

1. Clocks shall function from the same reference time-base and shall be capable of operating under independent clock values.

2. The Suppliers timing solution shall provide for application support for, no less than; tagging and reporting load profile data based on differing time-bases. For example: (reported to the master back office applications as Universal Time) and for local representation (for example, governing local registration for TOU and for customer display).
3. The clock timing reference shall be UTC is defined by International Telecommunications Union Recommendation ITU-R TF.460-6

6.5 Equipment Required for the Company FAN Laboratory

6.5.1 Description of the Company FAN Lab

Presently Company owns and operates a FAN laboratory that is used to test and evaluate communications equipment and applications. The lab is located at the Company Material Distribution Center (MDC) in Denver Co. The lab is equipped with two sectors of WiMAX base station equipment and is fully functional with network management and CPE devices. The lab also includes Ruggedcom 1500 series switch/routing equipment, Checkpoint firewalls and test equipment.

The FAN laboratory is isolated from a security perspective from any operating networks that are used by Company. Broadband connectivity is available by way of a 3rd party attachment.

This laboratory will be used on an ongoing basis for continued performance evaluation of communications systems and attached applications.

The test environment shall capable of operating in two modes, they are:

1. A stand-alone system (Headend and RF) without interacting with a co-located production environment (logical RF isolation)
2. A mode in which it can interact with production devices for test and troubleshooting purposes (not isolated at the RF level)

6.5.2 Requirements for the FAN Laboratory

1. Suppliers shall submit itemized priced proposals for the following equipment:
   a. Wi-SUN border router, Quantity 4
   b. Wi-SUN node capable of relaying wireless traffic, Qty 4
   c. Wi-SUN node, capable of acting as a routing DA endpoint , Qty 4
   d. Wi-SUN leaf nodes, Qty 6
   e. System Controller used for Network Management
   f. Standalone, non-redundant Headend including all hardware and software
   g. System manuals and instruction books
   h. 902-928 MHz USB programmable frequency source, 1w output, low noise, Qty. 2
   i. 4', SMA/SMA cables, double shield, Qty 20.
   j. Configuration tools as necessary to set-up and operate the WMN equipment, Qty 2
   k. Meter programming tools – both over-the-air and direct connect.
   l. AMI meters to mirror those used in deployment, Qty 4 sets of each device
   m. AMI meters and DA Field configuration tools, Qty 2
   n. Equipment and/or tools sufficient to RF isolate AMI devices (meters, etc.) for mesh testing purposes.
2. Suppliers shall propose and provide pricing for a method to achieve RF isolation between participating mesh devices having sufficient isolation specification to facilitate controlled performance testing under known data contention conditions and without interference from outside sources.

3. All equipment shall be use connectors of the SMA type having female connectors on equipment components and using male connectors on cables. Where SMA is not native, adaptors are required to be supplied.

4. Where Suppliers foresee other requirements, they are requested to describe the requirement and to provide pricing on the pricing template.

6.6 Equipment Required for Meter Shop Testing Facility

6.6.1 Functional Requirements of the Company Meter Shop

Presently Company owns and operates a meter shop in Denver Co. that is used to evaluate, re-service, test and assess meters and associated equipment.

The meter shop is used to:

a. Carry out full configuration programming of both meters and communication modules
b. Troubleshoot meter and communication problems
c. Test communication functionality and performance
d. Test, calibrate, and re-service meters
e. Perform acceptance testing for newly purchased meters
f. Reset both meter and communication modules

6.6.2 Equipment Requirements for the Meter Shop

1. Suppliers shall submit proposals that fulfil the functional requirements of the meter shop. Proposals shall include all of the necessary hardware, software, interconnecting cables, mounting boards, furnishings, test equipment, design services, integration services and set-up services, etc. that are necessary to equip the meter shop.
2. All proposals shall include any equipment that is necessary to ensure human safety against the effects of non-ionizing radiation in the frequency bands of interest in compliance to FCC and OSHA requirements.

6.6.3 Response Methodology

Response Proposals shall take the following form:

a. Description of the offering including narrative and equipment block diagram.
b. Itemized pricing on the Company Pricing template.
c. Description of the manner in which Back Office IT can interface with the equipment.
    I. Description of the installation methodology proposed
    II. Description by which any firmware or software can be upgraded.

6.7 Equipment Required By Field Technicians

6.7.1 Functional Requirement

In addition to any field installation or service that is required by the Supplier, Company requires field equipment for its own use, so as to carry out the following activities:

a. Carry out full configuration programming of both meters and communication modules
b. Troubleshoot meter and network communication problems
c. Test communication functionality and performance
d. Test, calibrate, and re-service meters

e. Reset both meter and communication modules

6.7.2 Equipment Requirements for Field Technicians

Suppliers shall submit itemized proposals that fulfil the functional requirements of the field technicians. Proposals shall include all of the necessary hardware, software, interconnecting cables, mounting boards, furnishings, test equipment, design services, integration services and set-up services, etc. that are necessary to equip the field personnel.

6.7.3 Response Methodology

Response Proposals shall take the following form:

a. Description of the offering including narrative and equipment block diagram.
b. A description; indicating the operational means by which the functional requirements are carried out
c. Tabulation of itemized pricing on the Company Pricing template indicating per unit costs and the estimated quantity of units required. Submit pricing on Xcel Energy AMI RFP pricing Template v4.xlsx
d. Description of the manner in which Back Office IT can interface with the equipment.
   i. Description of the installation methodology proposed
   ii. Description by which any firmware or software can be upgraded.

7 Services Requirements

7.1 Project Management Services

7.1.1 Requirements of the Engagement Manager

1. The Supplier shall provide an Engagement Manager for the duration of the project.
2. The Engagement Manager shall be responsible for managing the relationship with the Company and monitoring services delivery throughout the project. The Engagement Manager shall carry out the following duties:
3. Attend the project kickoff meeting;
4. Manage the contractual relationship between the Supplier and Company for the project duration (not the management of the project itself);
5. Act as the main point of contact between Company and Supplier organization;
6. Ensure the services delivered by Supplier conform to the contractual agreements;
7. Monitor the delivery of the contracted services against schedule, quality, scope and budget;
8. Manage Supplier resource planning and address resource performance issues;
9. Manage the financial aspects of the contract (billing for services, following-up on payments, etc.);
10. Act as the escalation point in the event of issues regarding Supplier resources/services;
11. Manage any dispute or conflict for purpose of resolution to the benefit of Company;
12. Report internally within Supplier organization on project performance (services delivery, progress, economics, etc.); and
13. Report to Company concerning the business aspects of services delivery, progress, economics, etc. on a monthly basis.
14. The Engagement Manager is not required on a full time basis. The Engagement Manager is required to:
15. Proactively fulfill the required duties, and
16. Be available for response to issues in no less than 48 hours following a request for involvement by Company.

7.1.2 Requirements of the Project Manager

1. The Supplier shall provide project management for all phases of the project by assigning a PMP (Project Management Professional Certified) Project Manager to the project.
2. The Project Manager in conjunction with designated Company Project Manager shall be responsible for coordinating all Company, Supplier, and Third-Party contractor (if any) activities diligently toward project success against system performance, schedule and budget metrics.
3. The Project Manager shall carry out the following duties:
   a. Establish, attend and participate in a project kickoff meeting in Denver CO. The Supplier shall use the session as an opportunity to gather detailed project requirements and to gain a full and detailed understanding of the work. Ensure that the Supplier's engineers and the Engagement Manager attend the kickoff meeting.
   b. At, and associated with, the kickoff meeting:
      a. Develop details of the project scope, WBS, and schedule to the team,
      b. Commence research into requirements,
      c. Establish a design criteria,
   c. Develop an initial formulation of design concepts in the form of draft sketches and tables
   d. Act in the role of single point of contact (SPOC) for Company project team.
   e. Coordinate project activities from the initial kick-off meeting through delivery of all contracted elements as well as any tasks mutually agreed to through a documented change order process, until final acceptance.
   f. Direct the project activities by way of assigning tasks and responsibilities and monitoring project progress and performance against task completion status, acceptability of performance, and project milestones.
   g. Prepare and issue weekly progress status reports and lead project status meetings by telephone or in person following company AGIS reporting mechanism.
   h. Maintain and distribute all documentation by way of email.

i. Report deficiencies and concerns proactively on an ongoing basis.
j. Coordinate the installation of the Back Office Systems system and associated training and acceptance testing.

4. Where the Suppliers Project Manager is directing or participating in the direction of work for which there are components of work attributable to Company, they shall be carried out through a process in which the work assignment is initiated, carried out and monitored through Company's Project Manager.

7.2 AMI and/or DA Oriented Design Service Requirements.

7.2.1 Understanding the Pricing Methodology

1. Company requires that Suppliers carry out designs in sufficient depth that pricing can be developed and submitted by Suppliers. The formal detailed design requirements are outlined in this RFP.
2. Suppliers are referred to "RFP Instruction to Suppliers, RFP Section 3.3" for description of the priority and methodological approach to design and pricing in respect of AMI and DA components.
3. Designs shall be "service oriented"; that is; they shall take into account the endpoint locations and performance requirements as inputs and develop realizable plans consisting of equipment and its' placement and configuration, that offer services that meet the requirements and objectives set out herein.

7.2.2 Scope

The Supplier shall lead and carry out the system designs. The scope of designs includes both AMI and DA related components as defined herein:

1. The design of WMN shall include selection of locations and equipment for nodes in the relevant deployment coverage area.
2. The design shall include any and all equipment configuration that is necessary for operation in compliance to the objectives and requirements set out in this RFP.
3. In all cases, designs shall accommodate the implementation of a network that serves both AMI and DA components without compromise.
4. The design package shall form a complete package having sufficient details and instructions and drawings to hand-off to an independent 3rd party integration team for construction.
5. Following the completion of the design packages, the Supplier shall include follow-up design services including, but not limited to:
   a. Integration support in the form of answering questions and supplying missing details, etc.
   b. Post construction inspection in accordance with the acceptance test plans.
   c. Post construction instructions to installation personnel for the purpose of rectification of deficiencies.
   d. Issuance of compliance to standards and design certifications.
   e. Issuance of Statements of Completion for each of the engineering designs.

7.2.3 Requirements for Design Services

1. The Supplier shall provide a complete network design for each of the Coverage Areas. The network design shall result in:
   a. A written detailed technical performance specification defining the design criteria applied.
   b. Determination of the location of field located equipment, taking into consideration, radio frequency signal propagation, technical performance specifications, physical topography, and network device site restrictions.
   c. A network design carried out in consultation with Company including consideration for and not limited to:
      i. Electric and gas meter read rates and reliability
      ii. RF availability for individual and cascaded wireless links
      iii. Packet throughput, latency and loss ratios

iv. packet prioritization and queuing,
v. routing protocols,
vi. Physical wiring, and IPv4/6 addressing.

2. A key tenant of the WMN design shall be to embody the basic networking principle of bulk carriage of mixed use traffic types for real-time flows for DA, gas, street lighting and AMI oriented applications and managing the flows to common interface points in a manner that prioritizes critical, time sensitive communications for DA devices over other less critical devices such as gas metering, AMI, and street lighting.

3. The design shall provide communications coverage for both AMI and DA oriented services based on the Network Performance Requirements set out herein

4. The design shall:

   a. Consider all required equipment and systems that are required to build a working WMN including network operational tools for network management and monitoring.
   b. Consider the issues of physical placement and mounting of all components
   c. Consider and take into account the requirements for networking for the ultimate applications that will run on the communications network.

7.2.4 Security Considerations for Design Services

4. The Supplier shall ensure that all of the security features as specified below, including any updates, are installed, applied, tested and operable to the full extent of the specification including those required for equipment Network Management. The required security feature specification sets are no less than:

   a. Security features specified in this RFP
   b. Security features specified in Suppliers Response to the RFP
   c. Security features that form part of IEEE 802.15.4g 2012 and IEEE 802.15.4e 2012
   d. Security features that form part of the Wi-SUN Alliance Technical Profile Specification v1 and proposed version 2, for IEEE 802.15.4g Standard-Based Field Area Networks.

5. The Supplier shall notify Company's Project Manager of any potential security threats and risks in circumstances where WMN data privacy and security are potentially compromised and in such circumstances shall act diligently and expediently to remedy the breach(s).
6. The Supplier is required to contribute to coordinating and carrying out the configuration of security protocols for the implementation in co-operation with other interfacing systems.
7. The Supplier shall communicate and dialogue with representatives of Company for the purpose of providing detailed explanations of the security features offered, their efficacy and their configuration.
8. The Supplier shall provide and install any and all security updates that are required during the warranty period and any extended warranty period.
9. The Supplier shall keep Company fully apprised of such security updates and seek Company approval prior to installation.

7.2.5 Required System Performance Technical Specification

The Supplier shall prepare a system performance specification. The performance specification shall specify and document, no less than:

   a. A design criteria; defining the expected traffic types and performance requirements.
   b. Guaranteed performance specifications as specified in this RFP. .
   c. The design rules, relating to physical placement, number of allowable hops, operating power, environmental conditions, obstruction losses, etc. that shall be adhered to so as to achieve the afore-stated specifications.

d. Details of networking requirements for interconnection of any NMS components to the WMN network components.
e. Statistical percentage of time in which the communications channel is able to deliver service performance to a quantifiable standard (as, for example, BER = 1e4 for 99.99% of time), or an alternative standard, as approved by Company.

7.2.6 Required Design Documentation / Deliverables

1. The design process shall be carried out in a manner that includes representatives of Company in the process for the purposes of information exchange and learning.
2. In the course of the design, the Supplier shall host meetings and Company shall be entitled to participate in design strategy sessions, midstream reviews and final design reviews.
3. The design shall be complete in written/graphical form, suitable to hand off to a qualified installation crew including no less than:

   a. Title, defining the site location and document identifiers, including list of authors and qualifications.
   b. Summary page including Company approval signature.
   c. Table of contents.
   d. List of figures and drawings.
   e. Design criteria
   f. Design principles followed,
   g. Statement of requirements.
   h. Design standards and metrics applied,
   i. Statement of required installation practices and standards.
   j. Wiring diagrams,
   k. The WMN design, all layers, Physical/IP/QoS/segmentation/queuing/protocols
   l. Mapping and geographic information delineating placement of nodes
   m. Integration instructions.
   n. Acceptance test plans.
   o. Supporting drawings.
   p. Network performance expectations,
   q. Anything else that is required so as to complete a design for a working system.

4. The design reference documentation shall be of sufficient substance that Company can, and without further instruction, use the prepared documentation to:

   a. place equipment in the field at known locations,
   b. mount equipment on the expected vertical assets,
   c. expect on-site service performance that is synchronized with the developed specifications

7.3 Requirements for Integration and Installation of the Outdoor Network Infrastructure Equipment

7.3.1 Required Outdoor Installation Activities for Network Components

1. This component of work does not include the installation of electric and gas meters.
2. Regardless of the installation methodology used to deploy the Network, the Supplier is responsible to make the system operate in accordance with the design and the specifications, including indoor and outdoor components.
3. For each Service Block and/or Company service territory considered, the Supplier shall undertake and carry out the installation integration leadership role. This role includes:
   a. Leadership in the form of a qualified Project Manager.
   b. Supplier establishment of a work schedule and plan, together, and in consultation with Company Project Manager and Company stakeholders.
   c. Carrying out whatever training is required for Company Field installation personnel.
   d. Act as a lead resource to guide the installation process.

e. Be available to the installation forces for problem solving.
f. Provide regular progress reports to the Company Project Manager.
g. Setting up and commission the equipment to performance in accordance with the ATP
h. Testing per ATP

4. Where the Supplier prepares a pricing proposal for installation of network components, the Supplier shall Itemize its' pricing proposal as follows:
    a. Identify "types" of structures on which network infrastructure components (border routers, relay nodes, etc.) will be located
    b. Develop an installation strategy and methodology for each type of installation structure
    c. Identify the quantity of installation events for each of the type of installation structures
    d. Compute installation costs by aggregating installation types with per unit prices
    e. Adjust installation pricing with any other costs and quantity discounts
    f. Document the infrastructure installation methodology in the format of an itemized tabulation of costs, summarized in accordance with the Coverage Blocks and Xcel service territories defined herein.
    g. Provide Company with a statement indicating the areas of responsibilities under which Company shall operate in regard to Installation obligations.
5. The Supplier is not responsible for:
    a. Structural engineering for tower/pole related services. These services will be carried out by a Third Party under direct contract with Company.
    b. Installation of endpoint communications equipment that is forming a component of the mesh network.
6. The Supplier is responsible for powering-on the Equipment and achieving fully configured operable conditions for the WMN including, but not limited to, all mesh nodes, network management systems and controllers.
7. The Supplier shall act as a team participant, together with Company and 3rd party participants, as authorized by Company, in a cooperative and supportive manner in matters involving the configuration of any related and required IT switches, router, RTU's and security equipment, etc., so as to ensure interface of all contributing systems that are required to make up the working WMN.

7.3.2 Development of an Acceptance Test Plan

1. The Supplier shall:
    a. Take a lead role in the development of the Acceptance Test Plan (ATP). The ATP shall include rigorous testing of the supplied Equipment using the manufacturer's specifications, the design criteria, the developed design, Wi-Sun Forum certification and IEEE802.15.4g/e as benchmarks.
    b. Ensure that the ATP provides thorough procedures and methodologies and a requirement to confirm the WMN compliance to the performance specifications that are required to be developed in the course of the design process. Such testing shall, at a minimum, test AMI and DA oriented metrics for each of the application service types identified (DA, AMI, etc.) and compare the results to the developed specifications.
    c. Tests shall be conducted in the on-site data traffic congested environment.
    d. Ensure that tests are developed that exercise any and all packet priority forwarding schemes where they relate to expedited forwarding for more critical applications such as distribution automation over less critical AMI traffic.
    e. Support Company testing protocols that are compliant to IETF RFC2544
    f. Consult with Company in development of the ATP.
    g. In the development of the ATP, include end-to-end performance evaluation of all system components that are required for operation of the WMN system including controllers, relay nodes, endpoints and network management systems.

h. Prepare the ATP on a schedule that ensures its completion and approval by Company no less than 4 weeks prior to the date when acceptance testing will commence.
i. Secure approval of the ATP form and content by Company prior to carrying out the tests.

7.3.3 Network Optimization

The Supplier shall carry out network optimization; no less than:

a. Complete an assessment of the preliminary as-built system performance with purpose to identify areas of design, installation and integration deficiency. Carry out assessments for no less than: meter collection metrics, routing, throughput, latency, bandwidth; resiliency and service availability;
b. Undertake design and identify installation revisions to be completed by Company
c. Manage the implementation of the network/system changes
d. Reassess the system performance and iteratively repeat the process until the network performance is optimized.
e. Upon completion, issue a notification certifying that the network Block has been optimized and indicate results of the measured performance.

7.3.4 Carrying out Testing per ATP

1. The Supplier shall lead Company's full acceptance testing of the completed systems. Acceptance involves:

   a. The development of an ATP,
   b. Testing against the ATP,
   c. Remedial actions where faults are discovered, and
   d. Final system inspection and acceptance by Company.

2. The Supplier shall complete all of the tests that are identified in the ATP.

3. The Supplier shall prepare and issue a formal report of the outcomes of the testing indicating no less than:

   a. The detailed outcomes of the testing.
   b. A summary table of the results showing a management level table of expected results and actual results.
   c. A narrative indication of the formal compliance to (1) manufacturer's specifications and (2) of the system specifications that are developed as part of the design process.

4. Individual endpoint or node device testing is not required per se, however; where function or performance problems are identified the Supplier is responsible to remedy the problem through repair/replacement processes in accordance with the applicable warranty provisions of the Major Supply Agreement. In any case of fault, Company shall be informed of its nature and the corrective action taken for its remedy including the expected repair schedule, by way of email to the Company Project Manager. If the problem is determined to be the result of an installation issue, then the resolution of the installation issue will be provided by Company.

7.3.5 Remedy of Deficiencies.

1. Following the completion of acceptance testing, the Supplier shall finalize the system set-up and configuration, and:
2. Configure the system in a finished state for hand-off to Company
3. Review the inventory of materials and services to be supplied to Company and remedy any shortages. Such materials include but are not limited to, handbooks, web links, maintenance manuals, configuration guides, hardware, firmware, training documents, etc.
4. Ensure and test that support procedures and protocols are in place.

7.3.6 Final System Inspection

1. The Supplier is required to inspect the completed installations and to deliver a statement of completion to Company no later than 5 days after completion.
2. Where deficiencies are identified, they shall be documented and subsequently remedied in accordance with the applicable warranty provisions of the Major Supply Agreement. Where remedial work is required by Company, the Supplier shall provide clear instructions of the work in the form of a written work order.
3. At project completion the documents shall demonstrate full completion of the work. The final Statement of Completion report shall include no less than:
   a. a summary narrative of the WMN project segment
   b. corrected drawings,
   c. configuration settings,
   d. statements concerning problems, issues and concerns,
   e. statement of compliance to the ATP,
   f. statement of compliance to manufacturer's specifications,
   g. photographs of the completed work

7.4 Requirements for Integration and Installation of the Indoor Network Infrastructure Equipment

7.4.1 Conditions for Installation

a. Company will own and operate all application, control and support servers
b. All servers will be on the premises of Company
c. Company will supply all necessary computational hardware and operating systems.
d. Company will perform software installations and updates.

7.4.2 Supplier Requirements

All software components are subject to the SSA.

7.5 Requirements for Installation/Meter Exchange of Electric Meters

7.5.1 General Requirements

The Supplier shall:

1. Install AMI meters in accordance with meter provider guidelines regarding installation procedures
2. Safely install/exchange meters of all form types in accordance with AMI Project Schedule (Schedule to be refined and fully developed after contract award) utilizing qualified employees
3. Complete meter exchange orders and ensure those orders are successfully transferred from Mobile Data Terminals (MDT's) to Company
4. Provide staging / cross-docking facilities for incoming of new AMI meters and replaced meters to be disposed.
5. Provide inventory control of new and used meters
6. Provide disposal of replaced meters
7. Capture GPS Latitude and Longitude. Coordinates must not be truncated to fewer than 5 places after the decimal point; for example 37.46668 rather than 37.466.
8. Provide any 'make-ready' components and consumable commodity supplies needed for completion of the mutually approved installation (e.g., transformers, arms, miscellaneous wire and raceways, wiring connectors for secondary voltage connections on utility poles, and

through bolts, lag screws, and/or stainless steel banding to mount RF pole-top devices to wood or metal poles)

9. Where installation is applied and priced for NSPM, NSPW and SPS coverage territories it shall be carried out using union labor.

7.5.2 Installation Rate

1. The installation rate shall be:

    a. 7% in 2018 – 98,643 meters
    b. 57% in 2019 – 803,235 meters
    c. 36% in 2020 – 507,307 meters

2. Throughout the meter deployment, Supplier will adhere to completing meter exchanges according to the provided reading/billing schedule. As billing cycles move into bill window dates, contractor will refrain from working in any billing cycles that are in the window.

7.5.3 Installation Procedure/Expectations for Single Phase Meters

1. Installation of Single Phase meters shall include devices of types FM1, 2 and12. This includes approximately 1,327,060 meters. Majority of the meters are socket type meters but there are a number of A-base meters that will require the installation of a socket adapter before the meter exchange can be completed. A-base meter quantities will be provided by form type at a later date.
2. The Supplier shall:

    a. Notify customer of your presence and intent
    b. Read and record meter number and index of meter being removed
    c. Verify new meter is the correct form type, class rating, voltage rating
    d. Open meter housing and check for safety hazards (stressed wires, broken blocks, previous signs of arcing, signs of extreme heat or melted materials etc.)
    e. Check for full voltage on line side of meter
    f. Install bypass jumpers where appropriate or engage meter bypass lever. If unable to by-pass make attempt to notify customer that service will be shut off momentarily to complete exchange.
    g. Remove meter.
    h. Tighten all connections in meter socket
    i. Verify 5th terminal is grounded
    j. Install meter
    k. Remove by-pass jumpers (if used) or disengage bypass lever.
    l. Complete voltage check on line a load side
    m. Close meter housing, seal with meter seal.
    n. Clean up work area
    o. Complete meter exchange in MDT
    p. If meters are installed in multi-unit applications the meter installer shall perform above steps for each meter before proceeding to the next meter exchanges at that location

7.5.4 Installation Procedure/Expectations for Three Phase Self-Contained Meters

1. Installation of Three Phase SC meters shall include devices of types FM16, This includes approximately 47,846 meters.
2. The Supplier shall:
    a. Notify customer of your presence and intent
    b. Read and record meter number and index of meter being removed
    c. Verify new meter is the correct form type, class rating, voltage rating

d. Open meter housing and check for safety hazards (stressed wires, broken blocks, previous signs of arcing, signs of extreme heat or melted materials etc.)
e. Verify voltage on line side of meter
f. Safely engage bypass lever
g. Remove meter.
h. Verify 7th terminal is grounded
i. Install meter
j. Disengage bypass
k. Perform service check
l. Close meter housing, seal with meter seal.
m. Clean up work area
n. Complete meter exchange in MDT

7.5.5 Installation Procedure/Expectations for Three Phase Transformer Rated Meters

1. Installation of Transformer rated meters shall include devices of types FM5, 6, 9, 35 & 36. This includes approximately 34,279 TR meters.
2. The Supplier shall:

a. Notify customer of your presence and intent
b. Read and record meter number and index of meter being removed
c. Verify new meter is the correct form type, class rating, voltage rating
d. Open meter housing and check for safety hazards (stressed wires, broken blocks, previous signs of arcing, signs of extreme heat or melted materials etc.)
e. Verify voltages at test block or potential stabs if meter has lever by-pass
f. If meter has test block, shunt current switches to ground to divert current from meter
g. Pull all voltage switches to de-energize meter socket
h. Pull meter from socket
i. Verify new meter is the correct form type, install meter, if meter has lever by-pass, dis-engag3e lever by-pass and proceed to step l.
j. Engage potential switches returning voltage to meter
k. Dis-engage current shunts returning current to meter
l. Verify voltages at test block or potential stabs if meter has lever by-pass
m. If CT cabinet is accessible, safely open CT cabinet
n. Based on information provided on meter exchange order, verify CT serial numbers, CT ratios, VT serial numbers (if applicable), VT ratio (if applicable), and meter multipliers are correct.
o. Replace meter cover and seal
p. Complete meter order in MDT

7.5.6 Required Tools and Instrumentation

1. The Company will provide the Supplier with necessary MDT's/tablet's for all field personnel performing meter exchanges. MDTs will be loaded with Xcel's software allowing for real time order completion.
2. Supplier shall be responsible to install MDT truck mounts for all field vehicles including all associated costs for installation and pedestal materials. Company will provide the MDT cradles but pedestals are a customized item depending on type of vehicle and will need to be secured to vehicle.
3. With exception of MDT/tablet the Supplier shall provide all tools required to perform and validate proper meter exchanges.
4. Company will provide the Suppliers with bar code scanners for each of the MDT's/Tablets issued.

7.5.7 Customer Notifications:

1. Company will send customer a mailings informing customers of the expected timeframe dates and procedures for the meter exchange prior to carrying out the meter exchange.

2. The Supplier shall attempt to contact customer upon arrival before accessing meter to perform exchange.
3. If unable to contact customer on arrival, Supplier shall safely attempt to gain access and exchange meter. A customer oriented notification of the completed or pending action shall be left at the customer premise in the form of a door hanger upon completion of meter exchange.
4. If unable to exchange the meter due to access issues, the Supplier shall follow procedure of 8.5.8

7.5.8 No Access Expectations:

1. The Supplier shall to make multiple attempts before returning order to Company consisting of:
   a. **2** field attempts
   b. **2** Phone/message attempts
   c. **1** no access letter
2. If the Supplier cannot exchange the meter after the multiple attempts, Supplier shall refer the meter exchange to Company for completion

7.5.9 Equipment Damage

In the event a customer outage should occur while attempting to complete a meter exchange, the Supplier's field technician shall:

a. notify customer (if home) about the unexpected outage
b. report outage to Supplier Supervisor or office personnel about outage and request a proper order be generated to Xcel for resolution
c. If unsafe condition exists, Supplier shall remain on site until relieved by another duly appointed and qualified company representative of the Suppliers company or until Company representative arrives on site

7.5.10 Property Damage (non-outage related)

1. If damage is caused by Supplier as a result of an improper or accidental action during the meter exchange process, the Supplier is responsible for all necessary repairs and associated costs.

2. If damage is unavoidable (due to pre-existing stressed wires or broken block) Company or the customer will be responsible for needed repairs and all associated costs.

7.5.11 Site Clean-up

All old or discarded meter related materials (demand seals, meter seals, used disconnect boots etc.) shall be picked up by Supplier and properly disposed of.

7.5.12 Cross Docking Inventory Management

1. The Supplier shall provide and equip cross docking facilities for receiving, storing and dispatching of new meters as well as storing meters being returned until disposal. Locations will vary dependent on geographic deployment.

2. Equipment to be provided by Supplier shall include but is not limited to tools, warehouse equipment (such as fork lift, pallet jacks), computers and associated connections, etc. Any computers requiring Company software (such as MDMS, CRS and Advantex) will be provided by Company.

3. During peak installation period, an average of 15,500 meter per week will need to be readily available for installation. To avoid any potential slowdown for lack of meter inventory, a 4 week supply of meters should be on hand at all times.

7.5.13 Inventory tracking/reporting expectations

1. All new meters will be electronically transferred to appropriate Supplier storerooms at cross docking facilities once they have passed acceptance (bar-X) testing by Company and have been purchased into Company's Monitor Device Management System (MDMS). It is anticipated that all meters will be shipped directly to Supplier's facility, and sample meters will be drawn for acceptance testing to be performed at the Company meter shop.

2. Company personnel will initiate meter transfer process of new meter shipments to a designated Supplier storeroom after each meter shipment has been purchased into MDMS and bar-X testing has been completed by Xcel.
3. In order to complete transfer process to Supplier's storeroom, Supplier will verify meters included in pending transfer are correct. Once verified, meters will be receipted for in MDMS to complete transfer process to Supplier's storeroom. New meter shipments will be quarantined until the transfer process is fully completed. Company will provide necessary training and access to MDMS to Supplier's office personnel.
4. On a daily basis, individual meters will be electronically scanned and transferred/assigned to each field technician for daily meter exchanges in an effort to help reduce the risk of lost meters. Scanners will be provided by Company. Company will provide necessary training for individual assignment of meters.
5. Individual meter inventory shall be conducted on a weekly basis by all field technicians using inventory software that will be available on MDT or tablet provided. Company will provide training for required weekly inventory.
6. Supplier will conduct a complete inventory (at least once a year) that may coincide with Company's own meter inventory or when deemed necessary. An electronic file of all meters, both new and used meters not yet retired will be provided by Supplier. Additional information will be given to Supplier prior to scheduled inventory date.

7.5.14 Disposal of Equipment Requirements

1. If field MDT/tablet is equipped with a camera, pictures of each meter will be required clearly showing the meter number and meter index before meter is de-energized.
2. Before and after pictures showing meter service and/or any pre-existing conditions worth noting may also be required to assist in any potential claims or disputes from customers. If MDTs are not equipped with cameras, Supplier shall be required to provide cameras. All pictures shall be stored by Supplier and readily available upon request. Company may request pictures to be uploaded to a site yet to be determined.
3. Sorting expectations:
    a. If all random and periodic testing is suspended during the project, meter sorting will not be required.
    b. If testing is not suspended, all meters selected each year for random/periodic testing will be saved and sent to Xcel's MDC facility for testing. Supplier will be required to initiate transfer in MDMS for each pallet of meters being sent back to the MDC facility.
4. Meter disposal/retirement process
    a. Prior to disposal, Supplier shall be required to provide a nightly file containing meters that have been removed from the field and are being retired and disposed. The required file format and layout for this process will be provided by Company.
    b. The Supplier shall separate meters and meter covers
    c. The Supplier shall remove and dispose of Itron ERT's and batteries in accordance with Company waste disposal policies and dispose of all retired meters.
    d. Company, at its option, may consider shipping meters containing mercury switches or batteries off-site for disposal. If sent off-site, Supplier shall be required to sort meters and palletize for shipment to off-site facility.

7.5.15 Inventory tracking/reporting expectations

1. All new meters will be transferred to appropriate Supplier storerooms once they have been purchased into Xcel's Monitor Device Management System (MDMS) and provided meters are being shipped directly to Supplier's facility.
2. Supplier will verify and receipt for all meter transfers to complete transfer process to Supplier storeroom
3. Individual meters will be transferred to individual field technicians for daily meter exchanges to help reduce the risk of lost meters
4. Individual meter inventory shall be conducted on a weekly basis by all field technicians

7.5.16 Miscellaneous materials

1. Company shall provide the required installation materials including but not limited to: seals, rings, locks, a-base socket adapters.
2. The Supplier shall notify Company of its installation material inventory requirements no less than 30 days prior to the scheduled requirement to for field installation.

7.5.17 Lock/key management

1. Company will provide the Supplier keys for all Company owned locks, lock boxes and barrel locks for accessing meters and/or locked meter rooms. All keys provided will be tracked and Supplier will be responsible for lost keys.
2. Additional keys that customers have provided to Company for meter access may also be available from the Company Meter Reading Department. Use of keys from the Meter Reading Department shall be coordinated and tracked by Supplier, and all keys will be returned promptly.

7.5.18 Required skill sets of meter exchangers

1. The Supplier shall prepare and deliver a field installation training program for all field installation personnel. The training program shall include no less than the following components:
    a. Instruction concerning matters of human safety to the general public, home/business owner and themselves.
    b. Instruction concerning the physical, electrical and mechanical characteristics of the installation sites
    c. Problem solving techniques
    d. Protocols for handling out-of-normal situations
    e. Methods to test and certify that installations are
    f. Methods to communicate with customers and public
    g. A testing program that validates each trainees knowledge and ability

2. The Supplier shall continuously assess and adjust the training program so as to meet evolving and changing installation requirements.
3. Where changes are made to installation/meter change-out processes, field installation personnel shall be informed and retrained if necessary.
4. No field installation activities shall be conducted by any person unless the individual has completed the training program and achieved certification to be a qualified field installation technician as granted under the training program.

7.5.19 Management Obligations

1. The Supplier shall provide for project management of the installation activities in accordance to methods outlined in PMP. The Supplier shall:
    a. Establish work scope, schedule and costs in consultation with Company
    b. Monitor work progress against the agreed-upon plans with Company
    c. Report on progress to Company weekly indicating no less than: (a) the assignments issues, (b) completions wrt assignments and project schedule, ongoing concerns and resolution progress and any new concerns.

2. Supplier to provide staffing for daily dispatching, scheduling of appointments (as needed), meter management/inventory, meter disposal and other administrative duties as determined by Supplier
3. The Supplier shall continuously assess and monitor its employee's performance in day-to-day work activities and where necessary, remove or retrain/requalify technicians.

7.5.20 Security screening/On-boarding procedures

1. Supplier employees shall not perform any work on behalf of Company or have access to Company's or its customers' property until the employee has successfully passed Company screening processes and been issued a badge.
2. Every Supplier employee will be required to begin screening process by filling out initial request at enterprise.fadv.com/pub/l/prospects/Company/Supplier

3. Once drug testing results and background screening has been completed and approved, Supplier will provide individual photos for each employee and ID badge requests will be submitted.
4. Employee ID badges shall be worn at all times and shall be visible at all times and used as a form of identification upon customer request
5. All newly hired Supplier employees or its contractors shall be required to complete Xcel's required compliance training courses within first 30 days of employment.
6. Yearly and on-going compliance training courses are required by Company. If the supplier's employee(s) do not comply with all training courses and due dates, the supplier employee will be immediately off boarded and denied access to Company property and data. This applies to all supplier personnel on the project regardless of whether or not they are working on meter sets, networks, software, on site or off site.

7.5.21 Minimum PPE Requirements

1. All Supplier field technicians shall be carry out their work meeting the Company PPE requirements. Included, but not limited to, items are:

    a. Clothing – 8 cal/cm2 long-sleeve shirt (w/Supplier logo), natural fiber/self-extinguishing clothing elsewhere, including under garments.
    b. Appropriate to function, fire rated pants
    c. Gloves – Class 0 gloves for voltages under 600v, leather gloves or equivalent for non-electrical tasks based on Supplier's hazard assessment
    d. Safety glasses - appropriate safety glasses/googles are required
    e. Safety shoes – steel-toe or equivalent
    f. Hard hats – hard hat with E rating
    g. Face shields – arc-rated face shield or hood appropriate for fault current (277-480v, 3 phase, etc.)

2. All PPE equipment shall be provided by the Supplier

7.5.22 Vehicle signage

1. Supplier shall provide vehicle stickers/magnetic signs approved by the Company, identifying the Supplier as an authorized contractor of Company
2. Supplier vehicles shall be well maintained and in good repair.

8 Support Services Requirements

8.1 Warranties

8.1.1 Warranty Methodology

1. For the first year, following successful completion of Acceptance Testing, all supplied equipment and services are covered under an inclusive blanket “repair or replace warranty”. See “Section 8.1.3 1st Year all-Inclusive Warranty”
2. Meter components are covered under the conditions of a “Meter Goods Warranty”. See “Section 8.1.4
3. Non-meter components are covered under the conditions of a “Goods other than Meter Goods Warranty”. See “Section 8.1.5
4. All firmware and software is covered under a long term Software Support Agreement See “Section 8.1.2

8.1.2 Software Support Agreement

1. Supplier shall provide support for the AMI Headend software. Details of the support plan shall be delivered to Company and include, but not limited to, resolution times of issues based on severity level.
2. Supplier shall provide Software Upgrades at no additional charge to Company. Such Upgrade Releases will include notes describing the fixes contained in each release.
3. Supplier offers to the RFP shall be inclusive of a full five (5) year warranty for all equipment and services supplied. Suppliers shall:
    a. Comply with the warranty conditions as agreed to between the Supplier and Company.
    b. Include provisions for system wide hardware, firmware and software repair or replacement under the condition that design and/or manufacturing defects preclude the reliable operation of the WMN system.
    c. Include the provision for field repair and/or replacement of equipment by the Supplier’s personnel for conditions where the equipment, functionality or its design is found to be defective or unreliable for its intended use.
    d. Include repair and replacement provisions having a MTTR of no more than forty-eight (48) hours for critical functionality/operation/components and seven (7) days non-service/non-critical functionality/operations/components.
    e. Any costs associated with the work (parts, labor, travel, etc.) required to remedy the defect, shall be the responsibility of Supplier.
4. Notwithstanding the warranty conditions between Company and the Supplier, the Supplier shall pass-through all warranties for 3rd party equipment, purchased by the Supplier and resold to Company.
5. Supplier shall include, in their proposals, an extended warranty covering repair and/or replacement of all supplied WMN components. Suppliers shall:
    a. Comply with the warranty conditions as stated herein or as agreed to, between the Supplier and Company.
    b. Offer annual pricing over a five (5) year period in the attached Pricing spreadsheet.

8.1.3 1st Year all-Inclusive Warranty

Supplier offers to the RFP shall be inclusive of a full first year all-inclusive warranty for all equipment, software and services supplied. Suppliers shall:

a. Comply with the warranty conditions as stated herein or as agreed to between Supplier and Company.

b. Include provisions for system wide hardware, firmware and software repair or replacement under the condition that design and/or manufacturing defects preclude the reliable operation of the WMN system.
c. Include the provision for field repair and/or replacement of equipment by the Suppliers personnel for conditions where the equipment or its design is found to be defective or unreliable for its intended use.
d. Include repair and replacement provisions having an MTTR of no more than 48 hours for critical components and 7 days for components that are not service impacting.

8.1.4 Warranty for Meter Goods

1. In addition to the all-inclusive warranty set out in Section 8.1.3, all Goods comprising of meters and NICs items (collectively, “Meters”) shall be subject to the warranties set out in this Section 8.1.3 for a period of twenty years from the date of inspection and the earlier of (i) acceptance of the Meters or (ii) fourteen days from the date of shipping (the “Meter Warranty Period”).
2. Supplier warrants that the Meters will conform to the kind, quality and capability designated or described by this Agreement and any applicable Specifications, SOW, Purchase Order or Work Order. Supplier warrants that the Meters furnished under the Agreement meet all Specifications and are free from defects in material, workmanship, and title for the Meter Warranty Period. The Supplier warrants that the Meters perform in a manner set forth in or required by the Agreement, and have been produced, processed, delivered and sold or licensed in conformity with all applicable federal, state and local laws, administrative regulations and orders. The Supplier shall execute, certify and deliver to Company any documents as may be required to effect or evidence compliance with such federal, state and local laws.
3. If within the first five (5) years of the Warranty Period (the “Initial Warranty Period”), the Meters furnished hereunder do not conform to these warranties and upon receipt of notice from Company of any failure to comply with the terms of the warranty, the Supplier, at Supplier’s cost, shall thereupon promptly correct any defect in the Meters, or at its option, replace the Meters after returned properly packaged to Supplier's authorized repair facility. Supplier shall pay Company a ‘first-set’ (labor) cost of thirty dollars ($30) per defective unit.
4. If Supplier chooses to replace the Meters, Supplier shall deliver the replacement Meters to Company and Company shall return defective Meters to Supplier. Supplier shall have no obligation to install the replacement Meters. If Supplier chooses to repair the defective Meters, Supplier shall pay to ship the Meters to Supplier's repair facility, and Supplier shall pay to ship the corrected Meters back to Company. Supplier shall promptly pay Company a ‘first-set’ (labor) cost of thirty dollars ($30) per defective unit.
5. If Supplier is unable to repair or replace any defective Meters, Company will return the Meters to Supplier and Supplier will refund to Company the monies paid by the Company for such Meters, including shipping costs. If such return occurs within the Initial Warranty Period, Supplier shall also pay Company ‘first-set’ (labor) costs of thirty dollars ($30) per unit.
6. If, in the period after the first five (5) years of the Warranty (the “Extended Warranty Period”), the Meters supplied hereunder experience failure rates in excess of zero point three (0.3%) percent annually, and Company notifies the Supplier, the Supplier shall make available like kind replacement Meters for such failed Meters exceeding the zero point three (0.3%) percent annual threshold in accordance with the following table. Annual failure rates shall be determined by dividing (a) the failed number of Meters in a one (1) year period (i.e. this is not a cumulative calculation) which shipped in a specific calendar year by (b) the total number of Meters shipped in that same specific calendar year. If it is determined that the failure rates are due to a defect in the product, then one hundred (100%) of the defective Meters will be replaced by like kind replacement Meters by the Supplier at the reduced rate.
7. Failures in years beyond the initial 5 year Warranty period will result in a discount off of current price of Meters as reflected in the negotiated Price list, as follows:

Failure Years	Discount
6-8	75% off current Company list price
9-15	50% off current Company list price
16-20	25% off current Company list price

8.1.5 Warranty for Goods other than Meter Goods.

1. In addition to the all-inclusive warranty set out in Section 8.1.3, all Goods other than Meters shall be subject to the warranties set out in this Section for a period of five (5)years from the date of inspection and the earlier of (i) acceptance of the Goods or (ii) fourteen days from the date of shipping (the "Goods Warranty Period").
2. Supplier warrants that the Goods will conform to the kind, quality and capability designated or described by this Agreement and any applicable Specifications, SOW, Purchase Order or Work Order. Supplier warrants that the Goods, furnished under the Agreement meet all Specifications and are free from defects in material, workmanship, and title for the Meter Warranty Period. Supplier warrants that the Goods perform in a manner set forth in or required by the Agreement, and have been produced, processed, delivered and sold or licensed in conformity with all applicable federal, state and local laws, administrative regulations and orders. The Supplier shall execute, certify and deliver to Company any documents as may be required to effect or evidence compliance with such federal, state and local laws.
3. Supplier shall provide warranty support for all other supplied Goods. Details of the support plan shall be delivered to Company and include, but not limited to, resolution times of issues based on severity level.
4. Supplier offers to the RFP shall be inclusive of a full five (5) year warranty for all non-meter Goods supplied. Suppliers shall:
   a. Comply with the warranty conditions as agreed to between the Supplier and Company.
   b. Include the provision for field repair and/or replacement of equipment by the Supplier's personnel for conditions where the equipment, functionality or its design is found to be defective or unreliable for its intended use.
   c. Include repair and replacement provisions having a MTTR of no more than forty-eight (48) hours for critical functionality/operation/components and seven (7) days non-service/non-critical functionality/operations/components.
   d. Any costs associated with the work (parts, labor, travel, etc.) required to remedy the defect, shall be the responsibility of Supplier.
5. Notwithstanding the warranty conditions between Company and the Supplier, the Supplier shall pass-through all warranties for 3rd party equipment, purchased by the Supplier and resold to Company.
6. Supplier shall include, in their proposals, an extended warranty covering repair and/or replacement of all supplied WMN components. Suppliers shall:
   a. Comply with the warranty conditions as stated herein or as agreed to, between the Supplier and Company.
   b. Offer annual pricing over a five (5) year period in the attached pricing table.

8.1.6 Warranty for Epidemic Failure

1. Supplier warrants that for the expected life of provided Goods, as set forth in the Specifications, Goods will not experience Epidemic Failure in the first ten (10) years of service.
2. "Epidemic Failure" means that the Goods have experienced any nonconformance to the Specifications due to the same type of defect at a cumulative failure rate of more than 10%, within (a) Company's total installed base ("Installed Base") or specific installation "Blocks" or (b) a particular release/version, manufacturing lot, or group of Goods, using particular subcomponents ("Subpopulation").
3. If (i) an Epidemic Failure occurs, (ii) Supplier becomes aware of the likelihood of an Epidemic Failure occurring in a Good, or (iii) it can be statistically proven by Company that an Epidemic Failure will occur, Supplier and Company will use their best efforts to understand the cause of the Epidemic Failure condition and, upon notice from Company, Supplier will, use its best efforts to correct and eliminate the Epidemic Failure as soon as possible by, at its expense, taking the following actions:
   a. Removing all units or providing a field upgradeable solution of the Goods for the Installed Base or the identified Subpopulation, as applicable, or;
   b. At Supplier's option, (1) replacing all the identified Products with replacement Goods which contain the correction and conform to the Specifications or (2) refunding payments made by Company for all the identified Goods and canceling all invoices for the identified Goods; (3) Providing seed stock units of Goods in order for a retrofit of the identified Goods within 180 days from the date the Epidemic Failure was declared. The number of seed stock units required will be calculated as follows:

      A = B*C = Seed Stock Units
      B = Material Cycle Time (Weeks)
      C = D/E = Retrofit Rate
      D = Number of units to be retrofitted
      E = Change Completion Date – Implementation Date (in weeks), or;

   c. Reimbursing Company for out-of-pocket expenses directly related to management of Goods replacement.

   Regardless of the above remedy options, Supplier shall provide a workaround until a replacement Goods are available and Epidemic Failure is resolved to the satisfaction of Company, at the sole expense of Supplier.

4. In addition, Company may cancel all outstanding purchase orders, work orders, and releases for the Goods subject to Epidemic Failure without further obligation.

8.1.7 Support Services, Extended Warranties.

Company may request Supplier to provide software support, extended warranties, maintenance support and similar technical support. The parties shall mutually agree upon the terms of any such extended warranties and/or support services in a SOW, Purchase Order, Work Order, or separate agreement.

8.1.8 Additional Warranty Terms

1. Notwithstanding any other provision of this agreement, and any warranties provided by Supplier to Company, Company hereby transfers and assigns to Company any and all manufacturer warranties regarding any Goods supplied pursuant to this Agreement.
2. Supplier represents, warrants and covenants that (i) Supplier is the owner of and has clear title to all Supplier Intellectual Property Rights related to the Deliverables that are being assigned or licensed, respectively, to Company in accordance with this Agreement, and is the owner of and has clear title to all Intellectual Property Rights related to the Work; (ii) Supplier has the right to assign and license the Supplier Intellectual Property Rights in the Deliverables, respectively, to

Company, and to provide the Work, in accordance with this Agreement without violating any Applicable Law or infringing upon or violating any Intellectual Property Rights of any Third Party, or breaching any agreement with any Third Party; (iii) the use by Company and its Affiliates of the Deliverables in their intended manner does not and will not violate any Applicable Law or infringe upon or violate any Intellectual Property Rights of any Third Party, or breach or be an unauthorized use relating to any agreement with a Third Party; (iv) Supplier has not entered into an agreement by which it assigned, transferred, licensed or otherwise affected any right, title or interest to any Deliverables that would conflict with its obligations under this Agreement and Supplier will not do so during the Term of this Agreement; and (v) all software used in or constituting Work or Deliverables is free from (a) any virus or other routine designed to permit access or use of such software or any other software by Persons not authorized by Company, or (b) Malicious Code; or except as provided otherwise in detail in a SOW accepted by Company, the Deliverables do not contain any Open Source Materials, and no Open Source Materials have been used in, incorporated into, integrated or bundled with, or used in the development or compilation of the Deliverables.

3. If Supplier proposes to make any material change to the process, formula, ingredients, components, source or other material aspect of Goods to be supplied, or is informed that any manufacturer of the Goods proposes to do so, Supplier will promptly provide written notification of the proposed change to Company. Such notification shall be accompanied by confirmation acceptable to Company that the Goods will continue to conform to the kind, quality and capability designated or described by the Agreement notwithstanding the proposed change.
4. Upon receipt of notice from Company of any failure to comply with the terms of the Agreement and/or these General Conditions including, without limitation, any defect with respect to the Work, either prior to or after Final Acceptance, Supplier shall, without additional compensation, correct any such defects within a time acceptable to Company and reimburse Company for any resulting costs, expenses or damages suffered by Company, including but not limited to costs of removal, reinstallation, re-procurement and any other Third Party costs, damages and losses incurred by Company. If Supplier fails to timely replace any such defective Deliverables or Goods or re-perform the applicable Work, Company may cause such defective Deliverables and/or Work to be provided or replaced by a Third Party and the direct and indirect expense thereof shall be the responsibility of Supplier. Company shall be entitled to deduct this expense and the resulting damages from amounts otherwise due to Supplier.

8.2 Maintenance Support Provisions

8.2.1 General Requirements

1. Suppliers shall offer a Support Services Agreement (SSA) for the initial 2 year period after which the Supplier shall offer a 5 year renewable service support agreement fulfilling the following requirements:
   a. Help desk/technical advice,
   b. Service/repair capabilities and,
   c. Equipment replacement supply capabilities
2. Suppliers shall prepare the SSA in the form of an itemized price proposal
3. Suppliers shall bind their Support Service Agreement conditions to the Service Level Agreement (SLA) as documented in Section 8.2.6 below.

8.2.2 Obligations of Company and the Supplier

1. Company will carry out first line performance, service monitoring and repair dispatch services for the meters, network systems and hardware. This means that Company will use the Network Management Services capabilities as contemplated as part of purchase in this RFP, together with its own internal resources, operating its Network Operating Center, to identify faults and performance issues and to dispatch work orders internally and to the Supplier in the form of "tickets".
2. It shall be the responsibility of the Supplier to address the service related matter of the "ticket" and to expeditiously participate in resolution of the service related issue in accordance with the SSA.

Support Services Requirements

8.2.3 Requirements of the Help Desk / Technical Advice

1. Provide a 365/24/7 staffed, help desk offering technical support by telephone with 1-800#, email and internet chat advice service.
2. Guarantee of access to a knowledgeable individual by telephone within 4 hours of a service support request.
3. Maintain and operate a tiered secure IT based fault reporting system, having the operational function of logging faults, assigning repair duties, tracking their remedy, and reporting status on a web interface.
4. The primary path to report and manage issues shall be through the customer support group. The Supplier support engineers shall help troubleshoot issues, open and track tickets, process requests and route issues to the correct Supplier teams for resolution.

8.2.4 Required Service Repair Capabilities

1. The Supplier shall provide and offer "on-call" repair technician support services to the Company.
2. On-Call Service technicians shall be qualified and trained concerning the technical and operational aspects of the supplied equipment as sold and used by the Supplier to Company.
3. The Supplier shall equip the on-call technician with all of the necessary spare parts, test, service equipment, tools, safety apparatus, etc., that is necessary to facilitate in-situ repairs.
4. Service response metrics shall be compliant to the SLA (Section 8.2.6)

8.2.5 Equipment Replacement Supply Capabilities

Where replacement equipment is necessary to effect repair, it shall be supplied under the terms of the relevant equipment warranty (Section 8.1.4).

8.2.6 Support Service Level Agreement

Table 8 / Customer Support Operational Metrics

Priority Level	Response Time	Resolution Process	Escalation Timeline	Customer Notification
1 resolution in 4 hours	Acknowledge by a personal phone call within 15 min (24x7)	24 x 7 x 365	Every 60 minutes: Support Manager After 1 hour: Dir., Customer Support After 4 hours: VP, Solution Services	Every 30 min
2 resolution 8 hours	Acknowledge by a personal phone call within 60 min of receiving alert (24x7)	24 x 7 x 365	Every 2 hours: Support Manager After 4 hours: Dir. Customer Support After 8 hours: VP Solution Services	Every 2 hours

3 resolution 24 hours or next business day	Acknowledge within 4 hours or next business day receiving alert or request M-F, 6 am-6 pm PT	M-F, 6 am – 6 pm (PT)	-	daily on business days
4 resolution 72 hours or next business day	Acknowledge within 20 hours of receiving alert or request M-F, 6 am-6 pm PT	M-F, 6 am – 6 pm (PT)	-	Weekly As needed

8.3 Spare Parts

1. Supplier shall maintain an inventory of spare parts in the USA and keep in force a priority order/dispatch process.

2. Supplier shall identify a list of recommended spare parts and consumables, if any, that Company should keep in Company inventory during the Warranty and Extended Warranty periods.

3. Supplier shall identify the spare parts and consumables, if any, that Supplier will keep in inventory for the duration of the Warranty and Extended Warranty periods.

4. Supplier shall provide a documented list of both Supplier and Company parts list with description, part number, pricing and recommended quantities.

5. Once agreed upon by both Company and Supplier:
    a. the volumes shall remain in force through the duration of the Extended Warranty. Inventory levels can only be down adjusted with an agreement of Supplier and Company, and
    b. firm pricing shall remain in force for the first two years of the agreement. Each consecutive year (one time per year) through the Extended Warranty term, a price review will occur between both Supplier and Company. Annual price adjustments will be capped at 1.5% of previous year's price.

8.4 Training Requirements

8.4.1 On-site training

1. The Supplier shall provide an on-site training program, which shall consist of a classroom program and instruction manual for operations, maintenance and installation personnel.

2. The on-site training program shall no less than cover the following topics:

    a. Theory and design of the supplied WMN.
    b. Operation techniques and features of the WMN.
    c. Hardware design configurations
    d. Meter firmware update – local and remote
    e. Meter programming - local and remote
    f. Headend training – Design, implementation, testing, maintenance, administrative and use
    g. Diagnostics interpretation for troubleshooting on a daily basis
    h. Radio communications in mesh networking
    i. Techniques for firmware upgrading including but not limited to meter metrology, meter modules, network components, DA endpoints

j. Safety issues concerning physical installation and RF
k. Understanding the mounting configuration and operation of the outdoor nodes
l. Physical installation techniques
m. Electrical connections
n. Grounding and lightning protection
o. Initial setup and testing
p. Problem solving and troubleshooting techniques
q. Compliance with FCC regulations in the installation and operation of the supplied WMN
r. Operations oriented training that is required for a Licensed back office solution and includes training to assist Company's IT staff in deploying AMI within Company's data center on Company hardware and software.

3. The training program shall include classroom time or field time with an on-site qualified instructor or subject matter expert.
4. The training program shall be comprehensive and interactive training program to system users, and system administrators and shall be intended to demonstrate and instruct on the subject of the Supplier's software and tools.
5. The training shall include field installation demonstrations and a takeaway installation manual to the extent necessary to grant participants a working knowledge of the Supplier's WMN and AMI meters without continuous support by the Supplier.
6. The training program shall facilitate involvement by no more than 15 individuals consisting of engineers, technicians, operations, information technology and management personnel.
7. The training program does not require a skills testing and certification program.
8. The training shall be set up in modules that will be relevant to different groups within Company.
9. The classroom training shall be supplemented with a set of web training Sections given at flexible times throughout the deployment or in a single or multiple-day live training session.
10. The training modules will include AMI system software training
11. Company may record any training provided by Supplier for use and distribution by Company for internal training purposes.

8.5 Factory Training

1. The Supplier shall offer an optional factory training program. Factory training shall mean training provided at Supplier's site on the use of systems.
2. Factory training shall be carried out on a per diem basis.
3. Factory training shall include topics to be defined by Company.

8.6 Optional Training Modules

1. The Supplier shall offer additional or repeat training courses which can be purchased as needed.
2. The Supplier will work with Company to ensure the correct level of training is provided.

9 Attachments

9.1 Computer Files with Meter Counts and Locations

1. Final – PSCo Meters.zip
2. Final – SPS Meters.zip
3. Final – NSPM Meters.zip
4. Final – NSPW Meters.zip
5. Final – PSCo 100G ERT Modules.zip
6. AMI Deployment Blocks with Gas Areas.pdf
7. AMI Block Deployment with gas only.kmz

9.2 Computer Files with DA Device Locations

1. Electric Distribution Points.xlsx
2. Gas Distribution Points.xlsx

9.3 Business Related Attachments

1. Xcel Energy AMI RFP Pricing Template v4.xlsx
2. Sample No Opportunity for SUB Letter
3. Creating Digital Signature
4. General Conditions for Major Supply Agreement
5. Safety Program Requirements
6. Sub-Contracting Plan
7. Sample Insurance Certificate
8. Essential Security Compliance Forms
9. FAN-Profile-Implementation-Poll-Template 0v02 Xcel Energy.xlsx
10. Advanced Metering Infrastructure - Request for Proposal v10 July 18th, 2016
11. Demonstration Test Plans and Assessments v4.0.docx
12. Xcel Energy table of Conformance Compliance.

**PUBLIC DOCUMENT –
NOT PUBLIC DATA HAS BEEN EXCISED**

Attachment 4F contains protected data including Trade Secret information pursuant to Minnesota Statute § 13.37, subd. 1(b), Security Information, pursuant to Minn. Stat. § 13.37, subd. 1(a) and are marked as "NOT PUBLIC." The information designated as Trade Secret derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use and is subject to reasonable efforts by the Company to maintain its secrecy.

Attachment 4F provided with the NOT PUBLIC version of this filing contain information classified as trade secret pursuant to Minn. Stat. § 13.37 for the above-noted reasons and are marked as "NOT PUBLIC" in their entirety. Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

Attachment 4F:

1. **Nature of the Material**: Attachment 4F is an internal assessment summaries that the Company has designated as Trade Secret information in their entirety as defined by Minn. Stat. § 13.37, subd. 1(b). The analysis and information contained therein has not been publicly released.
2. **Authors:** This summary was prepared by Business Systems and Sourcing employees and their representatives in 2017 (Schedule AMI 11) and 2015 (Schedule FAN12), in conjunction with the Company's review of hardware and software needs for its Advanced Metering Infrastructure (AMI) and Field Area Network (FAN) projects, respectively.
3. **Importance:** This Attachment contains information regarding bidder responses to requests for proposal (RFPs) issued by the Company, including sensitive pricing and other bid data; the Company's proprietary analysis of selected bids; market intelligence; and potential comparative bidder cost and negotiation planning information. Because these overall analyses derive independent economic value from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use, Xcel Energy maintains this information as a trade secret pursuant to Minn. Rule 7829.0500, subp 3.
4. **Date the Information was Prepared**: 2015

Annual Revenue Requirement
Summary of AGIS
2019-2024
($s)

	10364000	State of Minnesota Jurisdiction					
	Rate Analysis	2019	2020	2021	2022	2023	2024
1	Average Balances:						
2	Plant Investment	6,580,245	29,009,905	76,532,529	175,653,195	300,960,249	370,657,038
3	Depreciation Reserve	343,659	1,762,406	5,573,184	12,132,579	22,633,577	39,470,175
4	CWIP	6,077,959	4,923,865	10,920,662	11,207,715	4,295,266	1,139,888
5	Accumulated Deferred Taxes	215,274	1,186,806	3,367,552	7,591,449	13,587,298	18,886,510
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	12,099,271	30,984,558	78,512,455	167,136,882	269,034,640	313,440,240
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53	-	-	-	-	-	-
10							
11	Expenses:						
12	Book Depreciation	789,251	2,284,099	6,556,439	12,248,284	17,750,252	20,715,373
13	Annual Deferred Tax	429,201	1,513,864	2,847,628	5,600,166	6,391,532	4,206,892
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	1,218,453	3,797,963	9,404,067	17,848,450	24,141,784	24,922,265
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	2,312,376	7,589,079	16,657,950	32,098,686	40,379,438	35,533,814
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	24,950	128,118	132,406	187,323	60,166	649
22		-	-	-	-	-	-
23	AFUDC	77,380	626,878	276,556	431,934	120,184	56,678
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	251,665	647,577	1,640,910	3,526,588	5,972,569	7,021,061
27	Equity Return = line 6 x (line 46 + line 47)	652,151	1,660,772	4,208,268	8,958,537	14,420,257	16,863,085
28							
29	Tax Calculations:						
30	Equity Return = line 27	652,151	1,660,772	4,208,268	8,958,537	14,420,257	16,863,085
31	Taxable Expenses = lines 12 thru 14	1,218,453	3,797,963	9,404,067	17,848,450	24,141,784	24,922,265
32	plus Tax Additions = line 21	24,950	128,118	132,406	187,323	60,166	649
33	less Tax Deductions = (line 19 + line 23)	(2,389,756)	(8,215,957)	(16,934,506)	(32,530,620)	(40,499,622)	(35,590,492)
34	subtotal	(494,203)	(2,629,104)	(3,189,766)	(5,536,311)	(1,877,415)	6,195,507
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	(199,337)	(1,060,452)	(1,286,596)	(2,233,078)	(757,258)	2,498,965
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	(199,337)	(1,060,452)	(1,286,596)	(2,233,078)	(757,258)	2,498,965
39							
40	Total Capital Revenue Requirements	1,845,551	4,418,982	13,690,093	27,668,564	43,657,168	51,248,699
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	1,077,012	5,996,154	16,923,400	14,264,833	13,185,267	12,340,661
43	Total Revenue Requirements	2,922,563	10,415,136	30,613,493	41,933,397	56,842,434	63,589,359

	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**2.0400%**	**2.0600%**	**2.0500%**	**2.0800%**	**2.2000%**	**2.2200%**
45	**Short Term Debt**	**0.0400%**	**0.0300%**	**0.0400%**	**0.0300%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3900%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3800%**
48	**Required Rate of Return**	**7.4700%**	**7.4500%**	**7.4500%**	**7.4700%**	**7.5800%**	**7.6200%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**NA**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**
52	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
53	**IA Demand**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

Annual Revenue Requirement
Summary of AMR
2019-2024
($s)

	10364000	State of Minnesota Jurisdiction					
	Rate Analysis	2019	2020	2021	2022	2023	2024
1	Average Balances:						
2	Plant Investment	-	-	16,069,221	63,779,109	126,994,134	172,463,867
3	Depreciation Reserve	-	-	(273,703)	358,641	4,319,457	8,264,698
4	CWIP	434,960	2,162,643	1,727,683	-	-	-
5	Accumulated Deferred Taxes	-	-	250,835	1,135,177	2,495,094	3,662,003
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	434,960	2,162,643	17,819,771	62,285,292	120,179,582	160,537,166
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53	-	-	-	-	-	-
10							
11	Expenses:						
12	Book Depreciation	-	-	964,592	3,828,093	7,621,538	10,348,936
13	Annual Deferred Tax	-	-	501,671	1,267,010	1,452,827	880,989
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	-	-	1,466,263	5,095,104	9,074,365	11,229,924
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	-	-	2,747,099	8,329,070	12,780,553	13,473,681
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	17,140	83,696	-	-	-	-
22							
23	AFUDC	26,243	145,389	-	-	-	-
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	9,047	45,199	372,433	1,314,220	2,667,987	3,596,033
27	Equity Return = line 6 x (line 46 + line 47)	23,444	115,918	955,140	3,338,492	6,441,626	8,636,900
28							
29	Tax Calculations:						
30	Equity Return = line 27	23,444	115,918	955,140	3,338,492	6,441,626	8,636,900
31	Taxable Expenses = lines 12 thru 14	-	-	1,466,263	5,095,104	9,074,365	11,229,924
32	plus Tax Additions = line 21	17,140	83,696	-	-	-	-
33	less Tax Deductions = (line 19 + line 23)	(26,243)	(145,389)	(2,747,099)	(8,329,070)	(12,780,553)	(13,473,681)
34	subtotal	14,341	54,225	(325,697)	104,525	2,735,438	6,393,144
35	Tax gross-up factor = t / (1-t) from line 50	0.403351	0.403351	0.403351	0.403351	0.403351	0.403351
36	Current Income Tax Requirement = line 34 x line 35	5,784	21,872	(131,370)	42,160	1,103,342	2,578,682
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	5,784	21,872	(131,370)	42,160	1,103,342	2,578,682
39							
40	Total Capital Revenue Requirements	12,033	37,600	2,662,466	9,789,975	19,287,319	26,041,539
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	1,868	73,380	903,542	2,005,631	2,987,832	2,807,656
43	Total Revenue Requirements	13,901	110,980	3,566,008	11,795,606	22,275,151	28,849,194

	Capital Structure	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**	**Weighted Cost**
44	**Long Term Debt**	**2.0400%**	**2.0600%**	**2.0500%**	**2.0800%**	**2.2000%**	**2.2200%**
45	**Short Term Debt**	**0.0400%**	**0.0300%**	**0.0400%**	**0.0300%**	**0.0200%**	**0.0200%**
46	**Preferred Stock**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
47	**Common Equity**	**5.3900%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3600%**	**5.3800%**
48	**Required Rate of Return**	**7.4700%**	**7.4500%**	**7.4500%**	**7.4700%**	**7.5800%**	**7.6200%**
49	**PT Rate**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**	**0.0000%**
50	**Tax Rate (MN)**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**	**28.7420%**
51	**NA**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**	**86.6960%**
52	**MN JUR Direct**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**
53	**IA Demand**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**	**100.0000%**

THIS IS AN IMPORTANT SAFETY MESSAGE FROM XCEL ENERGY

[Date]
[Customer Address]

Customer Account Number: ___
Service Address: ___

RE: HAZARDOUS CONDITION FOUND –
CUSTOMER-OWNED EQUIPMENT MUST BE REPAIRED OR REPLACED

Dear [customer]:

During a recent visit to [insert service address] (the "Property"), a technician performing work for Northern States Power Company ("Xcel Energy") discovered the meter socket attached to your Property, is defective and does not comply with Xcel Energy's established Standard for Electric Installation and Use, a link to which is provided below ("Xcel Energy Standards"). For your information, Xcel Energy's standards and criteria applicable to meter sockets are set forth in Section 4.11 of the Xcel Energy Standards. Your defective meter socket poses a safety hazard to both you and your Property and requires immediate attention.

Xcel Energy will be replacing the existing electric meter at your Property with a new advanced electric meter. Prior to replacing your current meter and as a condition of continuing to receive electric service from Xcel Energy, Xcel Energy Standards require your existing meter socket be repaired or replaced due to its defective and hazardous condition.

As provided in Section 4.11 of Xcel Energy Standards, meter sockets are customer-owned equipment, which means you, as the owner of the Property, are responsible for the repair and maintenance of the meter socket. As a result, you would normally engage a professional electrician to replace your defective meter socket with a new meter socket that meets Xcel Energy Standards. Such replacement work would typically be done at your cost. However, because Xcel Energy will already be at your Property to replace the electric meter, Xcel Energy is offering to repair or replace your existing meter socket to achieve Xcel Energy Standards, at no cost to you.

To have Xcel Energy repair or replace your existing meter socket, please countersign this letter below. By signing below, you are providing Xcel Energy and its contractors your consent, as the owner of the Property, to perform the work necessary to repair or replace the meter socket, and are releasing Xcel Energy and its contractors from all current and future liability related to the meter socket. Additionally, by signing below you agree to take ownership of, and responsibility for, the new or repaired meter socket upon completion of the installation. Please return the signed letter either to the Xcel Energy technician, if the technician is present at the Property at the time of signing, or, if the Xcel Energy technician is not present, scan and email the countersigned letter to: XXXXX@xcelenergy.com.

If, during the repair or replacement of the meter socket by Xcel Energy, additional electric work is required by your Electrical Inspection Authority or Xcel Energy determines, upon closer inspection, that the work to remedy the hazardous conditions requires more than repairing or replacing your meter socket and Xcel Energy is unable to correct the hazardous condition, you agree to take full responsibility for any additional electrical work and costs beyond the new meter socket installed by Xcel Energy.

If you decide not to have Xcel Energy repair or replace your defective meter socket, you will be responsible for the repair or replacement work which is necessary to ensure the meter socket at the Property meets Xcel Energy Standards. This work will need to be completed prior to the replacement of the meter at your Property and as a condition to Xcel Energy's continued delivery of electric service to you.

For the most current Xcel Energy Standards for your area, please refer to the electric standards manual titled "Xcel Energy Standard for Electric Installation and Use" located at the following web address:

https://www.xcelenergy.com/working_with_us/builders/installation_standards

Additionally, if you would like more information about customer-owned facilities and customer responsibilities, please refer to Xcel Energy Electric Tariffs which are located on the Xcel Energy website, and also on file with the Minnesota Public Utilities Commission. Applicable Tariffs can be viewed by going to www.xcelenergy.com, select "Minnesota" and refer to the "Rates & Regulation" section on the website."

If you have any questions about this safety issue or the actions you need to take, please call the Xcel Energy Electric Meter Hotline at 1-800-422-0782, and press Option 2 for Minnesota.

Sincerely,
Manager Electric Meter
Xcel Energy

BY SIGNING BELOW, I HEREBY: (A) REPRESENT THAT I AM THE OWNER OF THE PROPERTY; (B) CONSENT TO XCEL ENERGY AND/OR ITS AUTHORIZED CONTRACTOR REPAIRING OR REPLACING THE EXISTING METER SOCKET LOCATED AT THE PROPERTY; (C) WAIVE AND RELEASE XCEL ENERGY AND ITS EMPLOYEES AND CONTRACTORS FROM AND AGAINST ANY AND ALL CURRENT AND FUTURE CLAIMS, LIABILITY, AND/OR RESPONSIBILITY RELATED TO OR ARISING OUT OF THE METER SOCKET AT THE PROPERTY OR THE ONGOING REPLACEMENT OR REPAIR OF SUCH METER SOCKET; AND (D) ACKNOWLEDGE AND AGREE THAT, UPON COMPLETION OF THE REPAIR OR REPLACEMENT WORK BY XCEL ENERGY OR ITS CONTRACTOR, I OWN AND TAKE ONGOING RESPONSIBILITY FOR THE REPAIRED OR REPLACED METER SOCKET AT THE PROPERTY.

Customer Signature: ___________________________

Customer Printed Name: ________________________

Property Address: ______________________________

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Date: ______________________

ADVANCED DISTRIBUTION PLANNING TOOL – LOADSEER

INTRODUCTION

Distribution planning is a key component of the Company's efforts to modernize its grid operations. As described in our November 1, 2021 Integrated Distribution Plan (IDP), we undertake a multi-step distribution system planning effort each year.[1] This process evaluates projected peak load on each feeder and substation in our system, so that we can analyze and identify needed risk mitigation projects, and put forward a proposal for the upgrades we anticipate are necessary to accommodate customer needs. While some of this baseline distribution forecasting is performed efficiently with our traditional tools, there is significant manual work and several "bolt-on" tools required to fulfill all of our historical distribution planning needs.

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

It had become necessary for our distribution planning tools to accommodate additional data granularity to better assess how technologies interact with the grid and how they change distribution system needs. Further, the Commission implemented distribution planning analysis and reporting requirements the Company must meet. These requirements include conducting scenario forecasting and assessing Non-Wires Alternatives (NWA) for certain system upgrade needs we identify in our planning process. Finally, our existing tool and its hosting server were out of date – and its vendor would no longer be supporting it in the near future. Considering these factors, the time was ripe to implement a new solution. We therefore initiated a solicitation and assessment process, selected LoadSEER as our preferred Advanced PlanningTtool (APT), and sought certification of it under Minn. Stat. § 216B.2425.

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[1] Docket No. E002/M-21-694

The Commission certified LoadSEER in its July 23, 2020 Order in Docket No. E002/M-19-666.

In support of our request for cost recovery in this docket, the balance of this document describes our planning process as it relates to LoadSEER, the technical attributes of LoadSEER and how they provide value to the Company and our customers, our selection process, LoadSEER's costs, and our implementation status.

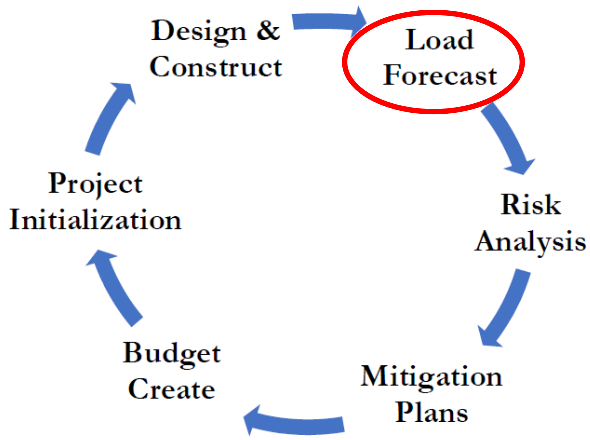
I. DISTRIBUTION PLANNING PROCESS AND TOOLS

Our distribution system planning process examines our distribution system's ability to serve customer peak load, identifies areas where there is a risk of overload or equipment failure, and makes plans to mitigate these potential overloads with additional or upgraded equipment. We complete this full cycle once per year, and the analysis examines projected conditions over a minimum of a five-year forward-looking time horizon. Forecasting loads across our system is an essential foundational step of our system planning process. We have had a set of planning tools that served the Company well in the past; however, as system planning and needs changed, and as software service offerings have evolved, the tool we used for our forecasting became out-of-date and could no longer effectively meet our needs moving forward.

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

The system planning process begins with forecasting customer loads across our distribution system, as shown below.

Figure 1: Annual Distribution Planning Process



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

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

B. Previous Load Forecasting Tool and Capabilities is Inadequate for the Future

Given the planning process described above, load forecasting is an essential foundational step in identifying potential constraints in the system, and balancing the need to stop potential outages before they happen with the need to manage costs to customers. The tool we used to facilitate our load forecasting efforts prior to procuring LoadSEER was called Distribution Asset Analysis (DAA). This tool was specifically tailored to the Company's system by its vendor, Itron, and was first implemented in 2003.[2] However, DAA was not capable of performing scenario analyses or aggregate feeder and substation specific forecasts. For these aspects of our distribution forecasting process, we had to use a combination of other tools and manual processes

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

Other analyses that DAA could not support and that LoadSEER does, include developing forecast scenarios that allow us to understand the grid impacts on varying levels of DER adoption, as well as evaluating NWA for traditional poles and wires mitigation projects as required by IDP requirements. LoadSEER additionally is needed to meet several of the Commission's objectives with regard to Grid Modernization. For example, one of the objectives of Grid Modernization Reports, as set forth by the Commission, is to ensure optimized utilization of electricity grid assets and resources to minimize total system costs. DAA was only able to evaluate

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[2] It is also important to note that the DAA tool and its hosting server are both outdated and reaching the end of their useful life. DAA's vendor was no longer providing ongoing updates or support for the tool beyond basic technical maintenance, and prior to our change to LoadSEER, the Company was its only remaining customer for this tool.

annual peak load conditions, so simply did not provide the capability to meet this objective going forward.

II. NEW TOOL EVALUATION AND SELECTION

Recognizing that DAA's capabilities would not be sufficient in a future with more customer technology adoption and without continuing vendor support, we began evaluating options for a new tool in 2015. As we moved through this process and received bid responses to evaluate different options, new distribution planning requirements from the Commission were also emerging that solidified much of what we recognized would be important tool attributes going forward.

As a result of a careful evaluation process – including bid responses, initial evaluations, and vendor demonstrations – we determined that LoadSEER by Integral Analytics would be the best option for conducting the depth and breadth of forecasting analyses needed going forward. LoadSEER's core benefits include the ability to:

- More efficiently and cost-effectively forecast distribution-level load,
- Conduct more advanced scenario analysis, and
- Better integrate our distribution planning with other Company planning processes.

As such, LoadSEER will position us well for the future of distribution planning, where its capabilities can grow with us and help us meet current and future Commission planning requirements.

A. Guiding Factors for Selecting a New Load Forecasting Tool

Overall, selecting a tool that enables us to provide customers with more value, meets our regulatory requirements, and eliminates manual data processing was of utmost importance in our evaluation process. Specifically, we see the following three key capabilities as essential to our selection process: (1) forecast granularity and ability to support NWA investment analysis, (2) ability to support scenario development, and (3) integration with other resources and planning processes. We discuss each of these in Section III B below.

B. RFI Process, Evaluation, and Selection

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

1. *Initial Screening and Evaluation Criteria Development*

First, we independently researched available tools and their vendors, in addition to well-known technology companies that we believed may be able to develop a customized solution. This research resulted in seven distinct vendor options representing a broad range of companies, from large providers to boutique solutions. After this research was complete, we issued a Request for Information (RFI) from the selected vendors. This RFI included a questionnaire with over 300 questions that were designed to help us further screen the potential new tools. At the same time, we also assembled a cross-functional team and a list of scoring metrics to evaluate potential options throughout the information and bid process. This team included individuals from the Distribution team, Enterprise Architecture, IT Security, and Sourcing. The team evaluated solutions across multiple metrics, including those in the non-exhaustive list of example scoring considerations we outline in Table 1 below.

Table 1: Example Distribution Forecasting Tool Evaluation Metrics (Not Exhaustive)

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

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

2. *Bid Evaluation and APT Selection*

Given the initial screening and bid evaluation described above, we eventually narrowed the distribution forecasting tool options to two potential products, as the third vendor failed to demonstrate their proposed solution met the project scope. At this point in the selection process, we invited the two vendors to demonstrate their respective tools and discuss whether and how they were able to provide the core functionalities we identified. We designed the demonstration assessments to build on vendors' RFI responses, ensuring a vendor's tool could sufficiently meet the most important functional requirements we set-out for our next distribution forecasting tool. Integral Analytics (IA) was able to show that the LoadSEER tool satisfied all of our requirements, which we note was the only vendor to do so. Further, IA showed that the tool would not require substantial customization for use with our other existing tools and analyses. Conversely, the other tool's vendor was unable to demonstrate most of the requirements during the course of our demonstration meeting, and would have required extensive customization to integrate. As a result, LoadSEER was our preferred choice given its analyses capabilities and ease of integration.

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

We describe below, LoadSEER and its capabilities with respect to the three core guiding factors we identified.

III. LoadSEER OVERVIEW AND IMPLEMENTATION

LoadSEER is a spatial load forecasting tool that combines several layers of detailed electric infrastructure, weather, economic and other data layers to forecast how future load and energy demands on the grid may change and thus, where upgrades may be required. We finalized the contract with IA in December 2019 and LoadSEER went into service in Minnesota in September 2020.

A. Tool Overview

LoadSEER is a forecasting tool for distribution loads that will replace and surpass our existing load forecasting tool in terms of providing insight into potential future load on each of our feeders and substation transformers. It does this by combining hourly historical load data with other Company and externally-provided data layers, and by using statistical methods to develop best-fit forecast analyses for every feeder and substation transformer on our system. LoadSEER allows historical load data to be imported directly from Supervisory Control and Data Acquisition (SCADA) systems, or at a more granular level from Advanced Metering Infrastructure (AMI).[3] The tool also can manage multiple data layers such as the Company's demand data and DER forecasts, as well as external geospatial and economic development data at a granular geographic level. The effect of each layer on the load forecast for a feeder or substation transformer means that it can be disaggregated from the overall forecast to provide information on the magnitude of impact resulting from any given factor as well as where, geospatially, those impacts are likely to occur.

B. Tool Capabilities and Benefits

LoadSEER provides various functionalities and benefits that make it an appropriate choice for our future distribution system planning. Here we outline how LoadSEER performs the three key functions we used as guiding factors in tool evaluation and selection. We also anticipate it will facilitate additional process automation, reducing staff time dedicated to completing our forecasting and reporting requirements.

[3] Note that the Company did not include AMI integration in the initial implementation due to lack of available data, but LoadSEER has the ability to integrate the data from AMI in the future.

1. Forecast Granularity and Non-Wires Alternative Investment Analysis

As noted above, our former tool was only capable of evaluating annual peak load at a feeder or substation level. LoadSEER provides more granular analyses options, in terms of both time intervals and proximity to the customer end point, which enables us to make more accurate decisions regarding investment needs and options. For example, with the introduction of DER onto the system, the differentials between minimum and maximum load during the day become both a more valuable and harder to predict data point. With more customers adopting DER and beneficial electrification, peak loading on a specific feeder may result in different levels of load, or at a different time of day than another feeder or than the system as a whole. In order to adequately assess the impact of DER on a given part of the grid, we need a tool that can forecast hourly load at the selected analysis point.

LoadSEER will be able to use historical distribution system SCADA and/or metering data, alongside built-in layers to generate statistically robust best-fit hourly load forecasts and shapes at the feeder and substation transformer level. Forecasting load shapes for each feeder and substation transformer, in particular ones that can be disaggregated from the effects of DER installed at a given point on the system, is an essential functionality the future. This enables more targeted N-0 and N-1 overload analyses in terms of time, duration, and location. Further, where upgrade needs are identified, these hourly shapes will provide helpful insights that allow us to better analyze potential NWA and distribution investment deferral analyses.

The most granular analysis point we have been able to utilize in distribution planning to-date is at the feeder level, but there may be value in analyzing sub-feeder data.[4] Each feeder is generally associated with approximately 1,500 to 8,000 endpoints, depending on the area's population density. However, as DER are often localized to a specific end point, being able to analyze load at a sub-feeder level may provide valuable insights for both necessary grid upgrades and future potential customer offerings.

Combined, a tool that enables these more granular analyses provides important information and efficiencies in assessing potential NWA to identified system upgrade needs. An annual peak load analysis alone cannot determine whether an identified upgrade is a candidate for NWA; more granular hourly data is required to determine

[4] We clarify that LoadSEER does not create sub-feeder forecasts. To the extent sub-feeder forecasts are available, LoadSEER is capable of analyzing them.

the magnitude of overloads at specific durations. In the past, we completed a peak load analysis 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 used these results to conduct risk analyses and develop theoretical load conditions if certain DER solutions were applied. However, LoadSEER can evaluate and project hourly load data on a feeder or other specific point on the grid, which facilitates more efficient evaluation of potential future overloads and whether a non-wires solution – such as solar PV, energy efficiency or energy storage – is a viable alternative to traditional upgrades. In short, we expect LoadSEER will reduce manual work and better identify opportunities for DER to provide value on our grid.

2. Scenario Development

As noted above, the Commission's Order setting out IDP requirements necessitates DER scenario analyses. In accordance with these requirements, we evaluate scenarios with a minimum level of assumed DER adoption, as well as medium and high adoption scenarios (corresponding to Base+10 percent and Base+25 percent, respectively). The objective of these analyses is to understand whether substantially increased levels of DER at a given point on the grid would result in different system overload conditions and upgrade needs. Prior to LoadSEER, we developed these scenarios manually outside our distribution forecasting tool, and because our previous DAA tool only evaluated annual peak load conditions, it was difficult to get a full picture of how these higher DER adoption scenarios may affect a given feeder or substation across the full year. LoadSEER provides these scenario forecasting capabilities intrinsically and contributes to more efficient forecasting processes and better assessment of how these increased adoption scenarios would affect specific feeders and substation transformers. LoadSEER also allows us to integrate these forecasts more fully into our analyses. Our DER forecasts will be disaggregated and allocated as growth in our hourly load forecasts, and will allow us to distinguish between loading conditions with and without the forecasted DER. Finally, LoadSEER also allows us to test the system loading impacts of different adoption scenarios within the tool. All of this functionality allows us to conduct DER scenario analyses more efficiently, and will help us better assess how different levels of DER may change peak loads and load shapes on specific feeders throughout the service area. This will be particularly important going forward as DER and beneficial electrification adoption increases in our service area.

3. *Aggregation and Integration with Other Resources and Planning Processes*

Finally, a key aspect of LoadSEER is its ability to integrate data source inputs, as well as communicate effectively with our other planning processes. As previously noted, our previous DAA tool only evaluated potential load growth on a feeder or substation. However, this level of growth had to be defined by the planner responsible for analyzing that specific point on the grid – and, DAA could not effectively aggregate forecasts from each point of analysis to ensure a reasonable fit with Company-wide top-line forecasts. We needed any new tool to be able to surpass DAA's capabilities in its ability to handle data inputs from various sources beyond the current set of inputs such as feeder-level SCADA data and existing customer usage inputs. External data layers, such as more targeted economic forecasts or projected DER adoption trends will help us more effectively forecast load changes into the future. The new forecasting tool also needed to be able to integrate potential internal future sources of data, such as interval data from our proposed AMI investments. LoadSEER enables both integration of data source inputs and it communicates effectively with our other planning processes.

With our pre-LoadSEER processes, our transmission planners had to scale distribution forecasts to the corporate level manually, for use in transmission planning processes and tools. The LoadSEER tool can be used to derive distribution-level load growth directly from our corporate-level forecasts that we use in Transmission and Resource Planning, so that these forecasts can be consistent across planning functions, which is also consistent with our regulatory requirement to align distribution planning to other system planning processes more closely – and particularly in terms of DER forecasts. This is key in part because Transmission and Resource Planning already use models that conduct analyses on hourly load and generation shape data; enabling distribution planning to analyze and forecast conditions on a similar time interval will enable all three planning processes to align better and more effectively than the current manual translation processes. The new tool will also provide modeling outputs that can be used in power flow modeling, which will support easier data handoffs between processes.

4. *Additional Benefits*

In addition to the benefits described above, LoadSEER can also provide two additional capabilities that will support our ability to meet additional regulatory requirements: (1) inform customer energy choices, and (2) perform increasingly granular analyses.

First, because LoadSEER is capable of developing hourly load shapes on feeders and disaggregating the effects of DER from net load, it will help us conduct better informed Hosting Capacity Analyses (HCA) in the future. For example, some daytime minimum load (DML) information required in the HCA is currently developed manually, by evaluating each feeder with a Community Solar Garden (CSG) installation and manually removing the estimated effect of the CSG on the feeder's estimated load. LoadSEER will provide forecasted hourly load shapes that will automatically disaggregate the effect of DERs in a particular area, so that we are able to assess DML without additional manual work. Second, LoadSEER can grow in its analyses capabilities in accordance with the granularity of the data we can provide, in particular with AMI and meter level interval data. When we implement AMI, we will have the ability for LoadSEER to integrate that sub-feeder level data, which will allow us to perform more precise forecasting and planning analyses. Overall, these added benefits support our determination that LoadSEER is the right tool to take our load forecasting capabilities into the next phase.

C. Implementation Status

After determining that LoadSEER was the best tool available to suit our distribution forecasting needs for the foreseeable future, we moved swiftly to procure and implement it. After finalizing the procurement, design, implementation, testing, which largely took place over the January through August 2020 timeframe – we began using the LoadSEER in our distribution planning processes for our Upper Midwest system in late 2020.

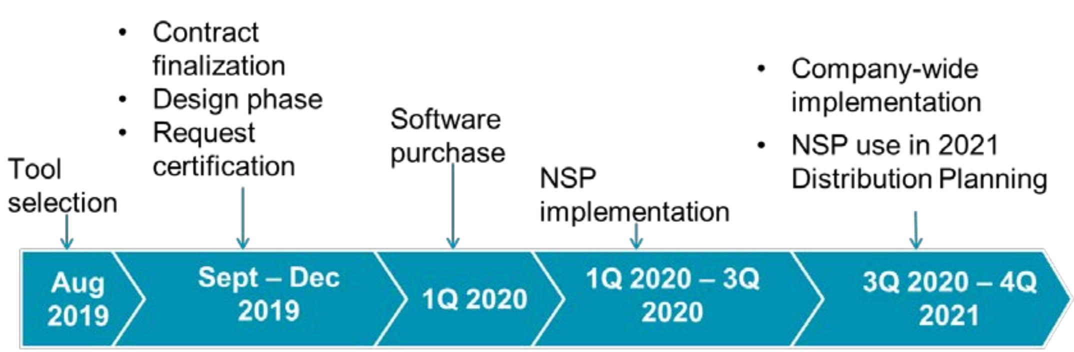
In order to prepare for implementation, we conducted detailed design preparations. In this phase, we underook activities such as developing an overall software implementation architecture, mapping functional requirements to test cases, and mapping from where each needed data stream will feed into the tool. We partnered with IA to complete the detailed design. During this phase, we firmed-up the scope of the project, including which modules/capabilities of the software we will use. We also conducted a system architecture review to determine how LoadSEER and its integration would be implemented within the broader context of our IT systems.

We completed the detailed design phase after finalizing the contract details in first quarter 2020 and followed it with a data mapping effort, in which we determined the source system and the location of the information for each level of data attribution that LoadSEER requires. Simultaneously, we reviewed and finalized the various requirements for the project as well as identifying the test cases that we would use to validate those requirements during the testing phase.

The next step for the project team was then to begin migrating this data to the LoadSEER system to prepare for implementation for use in our Upper Midwest distribution system planning process. Given the effort and coordination required to migrate vast amounts of data into a new, more granular forecasting tool, we expected this phase would take several months – and it did. We completed this in August 2020 and moved into the implementation phase. This included work such as necessary development to build data integration paths, prepare, migrate our data to the new system, and testing to ensure data is migrating correctly.

Finally, during the testing phase, we conducted the test cases identified in the design phase to identify and resolve any defects. After resolving any identified defects, IA began training and preparing our distribution planning team (and other stakeholders as necessary) for using the system after go-live where we would begin using it in our distribution planning process. We illustrate this timeline in Figure 2 below.

Figure 2: APT Implementation Timeline



We implemented LoadSEER for use in our Upper Midwest in time to partially use it for our Fall 2020 planning process. We implemented it in our operating company affiliates Public Service of Colorado (PSCo) and Southwest Public Service (SPS) in fourth quarter 2020.

V. COST AND BENEFITS

In our 2019 certification request, we estimated the cost to procure and implement LoadSEER Xcel Energy-wide at approximately $9.3 million – most of which was a capital expenditure. Our actual implementation costs were $9.3 million in total, with some variations between the capital and O&M components as we discuss below. We attribute the accuracy of our estimate to the advanced stage the project was in at the time of our certification request.

As the tool is a shared asset, all Xcel Energy operating companies incur a proportional share of overall costs. At the time of certification, we expected the upfront costs for LoadSEER would be apportioned to Xcel Energy operating companies based on each company's number of distribution feeders. Using this approach, we estimated NSPM-specific costs at approximately $4 million. Actual costs allocated to NSPM were approximately $3.5 million, or $500,000 lower than our estimate. The difference between estimated and actual costs for NSPM is largely attributable to use of a different (Gross Electric Distribution Plant) allocation method among operating companies.

In the balance of this section, we discuss the overall costs, the allocation among operating companies, and the cost benefit analysis we performed and initially submitted with our 2019 certification request.

A. Implementation and Ongoing LoadSEER Costs

The upfront costs to procure and implement LoadSEER were comprised of capital costs associated with the software liense and Company integration costs and O&M costs for prepaid maintenance (5 years), an annual software hosting fee, and miscellaneous Company costs as outlined below.

Table 2: LoadSEER Planning Tool Capital and O&M Cost Categories

Cost Category	Explanation
Total Capital	
APT Installation and License	Majority of costs incurred in 2020 for perpetual license and project/program management and contingencies.
Company IT System Integration	Costs incurred in 2019-2020, for initial business systems implementation and year 1 contingencies.
Total O&M	
APT Software Maintenance	Pre-paid five-year maintenance service and ongoing software hosting, plus year 1 contingencies.
Company IT Maintenance and Support	Costs incurred in 2019-2020, for implementation and change management expenses, including year 1 contingencies.

As discussed above, total actual costs were on budget and the NSPM portion was under budget, as outlined below.

Table 3: Actual Implementation Costs Compared to Budget – Xcel Energy-Wide through June 2021 (millions)

	Actual	Budget	Difference
Total Capital	$8.1	$8.6	**($0.5)**
Total O&M	$1.2	$0.7	**$0.5**
Total	**$9.3**	**$9.3**	**$0.0**

On an NSPM Operating Company basis, actual capital costs totaled $2.9 million and O&M totaled $0.6 million, for a total of $3.5 million.[5] This is below the soft cap that the Commission established in its Order certifying LoadSEER.[6] We describe the capital and O&M costs in more detail below.

[5] For purpose of cost recovery, we remove internal labor and then allocate the remaining costs to Minnesota based on the CAAM.
[6] In certifying LoadSEER, the Commission limited the Company's cost recovery to $4 million, unless the Company showed by clear and convincing evidence that the costs were reasonable, prudent, and beyond its control. *See* Order Point No. 14 of the Commission's Order Accepting Integrated Distribution Plan, Modifying Reporting Requirements, and Certifying Certain Grid Modernization Projects in Docket No. E002/M-19-666 (July 23, 2020).

1. *Capital Procurement and Implementation Costs*

IA provided several options for licensing and deploying the LoadSEER software, which we carefully evaluated for fit, cost, and ease of use. Ultimately we chose to procure the tool as a hosted solution on a perpetual license. This means that the vendor will provide for our use of the tool on their servers, which we access via the Cloud – it affording nearly instantaneous updates to the tool when the vendor makes improvements or adds new features, and it is not necessary for the Company to procure or maintain its own server resources. We determined using LoadSEER as a hosted solution was the preferred choice primarily based on its cost-effectiveness over the timeframe we forsee using the tool. We also expect LoadSEER and IA's continual updates will provide the features we need more timely and far into the future, even beyond the typical seven-year asset life we use to assess software investments.

Our internal analyses showed that a perpetual license option would be the most cost-effective if the Company uses this tool for eight years or more, which we believe is realistic for the Company. To provide a point of comparison, we used our previous forcasting tool for 16 years before switching to LoadSEER – and given the cost to acquire and integrate a new system, we do not anticipate making another change within eight years. Further, at present, there are few to no alternatives that can provide comparable functionality, and emergent tools from other vendors remain in development phases. Especially given LoadSEER's continual updates and its "room to grow" with our AMI capabilities, we expect the hosting option and the perpetual license the most prudent path forward.

2. *O&M Implementation Costs*

Upfront O&M costs included five years of pre-paid maintenance and a small amount of Company O&M for things such as external labor related to contract management and support for business process analysis and design and internal labor related to financial management. Ongoing, we will incur an annual external server hosting cost and internal Company support. We note that in terms of the cost-benefit analysis we performed and submitted with our 2019 certification request, we accounted for annualized maintenance and service contract costs beyond year five when our initial pre-paid period ends. We summarize this analysis in Table 4 below. We also note that our ongoing maintenance costs for LoadSEER will be lower than the amount we were incurring for DAA (our previous forecasting tool) that, comparatively, has limited functionality; on an annualized basis the savings amounts to over $100,000 Xcel Energy-wide.

Given the capabilities and benefits LoadSEER enables for our distribution planning processes, we are confident that the investment is in the interest of both customers and the Company.

B. Cost-Benefit Analysis

LoadSEER is a foundational element of our increasingly robust distribution planning process to meet the needs of an evolving grid and as we have discussed, we will realize significant benefits. We conducted a cost-benefit analysis for our 2019 certification request. While that benefit-to-cost ratio did not indicate direct positive returns, our current tool was beyond its useful life and the investment in an advanced planning tool is essential to performing the more sophisticated analyses our evolving grid requires going forward. As we have discussed, we expect LoadSEER to also provide multiple additional qualitative benefits that, while challenging to quantify in dollar terms, are tangible and substantial. Our 2019 cost benefit analysis showed that over the full seven-year assumed financial life of the software, we expect a benefit-to-cost ratio of 0.35, as shown below.

**Table 4: NSPM APT Benefit-to-Cost Ratio –
Based on Estimated Costs at time of 2019 Certification Request**

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

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

The quantifiable benefits relate to two key factors. First, the avoided ongoing subscription cost of our current distribution forecasting tool and a Microsoft Excel plug-in tool.; as noted previously, our procurement of LoadSEER will result in reduced maintenance costs of over $100,000 on an annualized basis. Second, our estimated annual deferred capital value realized as a result of LoadSEER's enhanced capabilities; as LoadSEER is able to more accurately forecast the needs on the system through the incorporation of DER, energy efficiency, and corporate growth forecasts, we expect it may help to defer certain upgrades that would have otherwise been indicated with a less precise tool; we estimated this value based on the benefits of deferring one feeder upgrade for three years.

In addition to these quantifiable benefits, the qualitative benefits of an improved tool further supports our procurement of LoadSEER. Some of the additional benefits we expect from LoadSEER as compared to our existing tools and process include:

- Hourly analyses for all measured points on the grid that examines the minimum and peak loading differentials, load shapes and more clearly shows the impact of DER;
- Improved load forecasting precision that can account for two-way power flows;
- Enables easier identification of opportunities for NWA investments for projected overloads and contingencies;
- Processes forecasting scenarios within the tool, rather than requiring an outside, manual process;
- Enables analysis closer to the customer than the traditional feeder and substation analysis, to examine impacts of DER at a more granular level;
- Better integrates customer data, including from future AMI deployment;
- Aggregates forecasts to ensure better consistency with corporate-level forecasts, and better integration into other Company planning processes

While it is difficult to quantify these qualitative benefits, we believe they are substantial and are important to consider in assessing the prudence of our LoadSEER investment.

In summary, LoadSEER will substantially facilitate our distribution planning process, enhance our HCA processes, support grid modernization while enhancing reliability, and facilitate increased conservation opportunities.

VI. ONGOING AND FUTURE PLANNED USE OF LOADSEER

As previously noted, we began using LoadSEER at the end of third quarter 2020. Due to the timing, it was not possible to complete a full load forecast using LoadSEER in 2020. Since then, our focus has been on working with IA to resolve the defects and bugs that are typical with any software implementation. We have also been working with IA on implementation of software enhancements to enable more efficient forecast creation in the future. This work will help ensure that we are able to integrate LoadSEER into our planning process as smoothly as possible in future planning cycles.

The forecast we create in Fall 2021 will be our first effort at fully creating a forecast in LoadSEER. Since this will be the first full LoadSEER forecast, our focus is primarily on replicating a more traditional load forecast in the tool, while providing a foundation for the use of more advanced features in the future. Due to the complexity of the tool and the significant change in forecasting methodology that it introduces into our planning process, a staged approach is necessary to allow us adequate time to better understand the process and become more comfortable with the analyses. After proving out the core functionality of the tool with our 2021 planning process, we expect to then introduce more advanced features in future planning cycles as outlined below.

Hourly analysis for all measured points on the grid that examines the minimum and peak loading differentials, load shapes and more clearly shows the impact of DER

- Hourly load shapes incorporated in 2021 forecast
- Impact of DER incorporated in 2022+ forecasts (2021 forecast will only produce a native load forecast)

Improved load forecasting precision that can account for two-way power flows

- This capability is intrinsic to the software, but we expect to begin fully utilizing this capability in 2022+ forecasts

Enables easier identification of opportunities for NWA investments for projected overloads and contingencies

- Relies on hourly forecasted shapes, which we are incorporating in our 2021 forecast

Processes forecasting scenarios within the tool, rather than requiring an outside, manual process

- Only one forecasting scenario for 2021 forecast; multiple scenarios to be implemented in 2022+ planning years

Enables analysis closer to the customer than the traditional feeder and substation analysis, to examine impacts of DER at a more granular level

- Relies on ability to export line section forecasted loading to Synergi model, which we included in our initial 2020 forecast process

Better integrates customer data, including from future AMI deployment

- Customer billing data and metadata included in 2020 forecast
- AMI data to be implemented in a future project TBD

Aggregates forecasts to ensure better consistency with corporate-level forecasts, and better integration into other Company planning processes

- We used this capability in our initial 2020 forecast process.

CONCLUSION

In summary, LoadSEER is an important and essential foundational tool that will help the Company carry out the requisite analyses for a modern grid. Our actual implementation costs were below budget and the cap set by the Commission, and are reasonable and prudent for the advanced planning capabilities provided by the LoadSEER tool.

Transmission Project Implementation Schedule

Project Name	Regulatory Approval Docket No.	Regulatory Approval Filing Date	Regulatory Approval Order Dates	Design/Engineering/ Procurement	ROW Acquisition	Construction Start	Projected In-Service	Current Status	MISO Approval
CAPX2020 Brookings	ET-2/TL-08-1474 EL10-016	12/29/2008 11/23/2010	Certificate of Need 5/22/2009 Route Permit MN 9/14/2010 Route Permit SD 6/14/2011	November 2011	November 2011	October 2011	March 2015	Project is in-service.	N/A
CAPX2020 – Fargo	E002, ET2/TL-09-246 E002, ET2/TL-09-1056	4/8/2009 10/1/2009	Certificate of Need 5/22/2009 Monticello – St. Cloud Route Permit 7/12/2010 St. Cloud – Fargo Route Permit 5/1/2011	Monticello – St. Cloud Engineering Start 1/2/2010 Procurement Start 7/1/2010 St. Cloud – Fargo Engineering Start 10/1/2010 Procurement Start 7/1/2011	Monticello – St. Cloud 7/15/2010 St. Cloud – Fargo 5/15/2011	Monticello – St. Cloud 11/1/2010 St. Cloud – Fargo 12/26/2011	Monticello – St. Cloud 12/21/2011 St. Cloud – Fargo 10/15/2015	Monticello – St. Cloud segment is in-service. St. Cloud – Fargo segment is in-service.	N/A
CapX2020 – La Crosse (Local, MISO, and WI)	E002/CN-06-1115 Local & MISO: ET-2/TL-09-1448 (MN) WI: 5-CE-136 (WI)	8/4/2006 1/19/2010 1/3/2011	MN Certificate of Need 5/22/2009 MN Route Permit 5/30/2012 WI Certificate of Public Convenience and Necessity 5/30/2012	October 2011	January 2012	January 2013	September 2016	Project is in-service.	N/A

Project Name	Regulatory Approval Docket No.	Regulatory Approval Filing Date	Regulatory Approval Order Dates	Design/ Engineering/ Procurement	ROW Acquisition	Construction Start	Projected In-Service	Current Status	MISO Approval
Big Stone – Brookings	EL12-063 (SD) EL13-020 (SD)	12/19/2012 6/3/2013	Facility Permit for 35 miles of planned line issued January 2007 (recertified May 10, 2013) Facility Permit for 40 miles of planned line issued February 20, 2014	June 2014	December 2016	August 2015	September 2017	Project is in-service.	December 2011 (MTEP11)
La Crosse – Madison	5-CE-142 (WI) 137-CE-160 (WI)	08/19/2013	WI Certificate of Public Convenience and Necessity 4/23/2015	May 2014	Start-June 2015 End-May 2018	August 2016	December 2018	Project is in-service	December 2011 (MTEP11)
Huntley-Wilmarth	E002,ET6675/CN-17-184 E002,ET6675/TL-17-185	6/30/2017 1/22/2018	8/21/2019 8/21/2019	July 2019	Start–September 2019 End –estimated December 2021	Start – June 2020 End – estimated December 2021	Estimated: December 2021	Project is in Construction	N/A

Line No:	Eligibility Date	NSPM Rider Project	NSPM Rider Sub Project	Pre Eligible AFUDC	CWIP Expenditures excluding Internal Labor									Total	Previous Filing Expenditures	Dollar Variance	% Variance
					Pre-2019	2019	2020	2021	2022	2023	2024	2025	2026				
1	1/1/2017	**AGIS - ADMS**															
2			Capital	370,966	18,407,057	7,061,268	6,084,801	4,149,226	1,623,951	2,467,504	2,194,837	3,561,612	(529)	45,920,691	49,779,110	(3,858,419)	
3			**Total**	**370,966**	**18,407,057**	**7,061,268**	**6,084,801**	**4,149,226**	**1,623,951**	**2,467,504**	**2,194,837**	**3,561,612**	**(529)**	**45,920,691**	**49,779,110**	**(3,858,419)**	**-8%**
4	12/1/2020	**AGIS - AMI**															
5			Capital	1,332	1,447,263	302,203	4,211,957	9,714,030	72,023,459	104,519,786	88,317,372	(8,941)	-	280,528,460	-	280,528,460	
6			**Total**	**1,332**	**1,447,263**	**302,203**	**4,211,957**	**9,714,030**	**72,023,459**	**104,519,786**	**88,317,372**	**(8,941)**	**-**	**280,528,460**	**-**	**280,528,460**	**100%**
7	12/1/2020	**AGIS - FAN**															
8			Capital	69,764	216,894	1,451,590	1,317,902	5,415,646	8,131,772	13,488,951	7,685,307	677,707	54,296,005	92,751,537	-	92,751,537	
9			**Total**	**69,764**	**216,894**	**1,451,590**	**1,317,902**	**5,415,646**	**8,131,772**	**13,488,951**	**7,685,307**	**677,707**	**54,296,005**	**92,751,537**	**-**	**92,751,537**	**100%**
10	12/1/2020	**AGIS - LoadSeer**															
11			Capital	-	-	-	2,587,275	180,759	-	-	-	-	-	2,768,034	-	2,768,034	
12			**Total**	**-**	**-**	**-**	**2,587,275**	**180,759**	**-**	**-**	**-**	**-**	**-**	**2,768,034**	**-**	**2,768,034**	**100%**
13	1/1/2022	**AGIS - TOU Pilot**															
14			Capital	88,026	5,327	4,688,088	345,550	(785)	-	-	-	-	-	5,126,206	-	5,126,206	
15			**Total**	**88,026**	**5,327**	**4,688,088**	**345,550**	**(785)**	**-**	**-**	**-**	**-**	**-**	**5,126,206**	**-**	**5,126,206**	**100%**
16	1/1/2016	**Big Stone-Brookings**															
17			Land	-	3,519,600	-	-	-	-	-	-	-	-	3,519,600	3,519,600	-	
18			Line	421,972	46,041,829	96,824	1	-	-	-	-	-	-	46,560,626	46,559,810	815	
19			Sub	4,225	4,437,189	8,505	-	-	-	-	-	-	-	4,449,918	4,427,272	22,647	
20			**Total**	**426,197**	**53,998,618**	**105,328**	**1**	**-**	**-**	**-**	**-**	**-**	**-**	**54,530,144**	**54,506,682**	**23,462**	**0%**
21	1/1/2012	**CAPX2020 - Brookings**															
22			Land	-	38,630,568	8,584,701	-	-	-	-	-	-	-	47,215,269	47,215,269	(0)	
23			Line	4,092,148	357,924,100	(2,582)	-	-	-	-	-	-	-	362,013,666	362,016,248	(2,582)	
24			Sub	38,858	53,624,739	-	-	-	-	-	-	-	-	53,663,597	53,663,597	-	
25			**Total**	**4,131,006**	**450,179,407**	**8,582,119**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**462,892,532**	**462,895,114**	**(2,582)**	**0%**
26	5/1/2009	**CAPX2020 - Fargo**															
27			Land	-	20,269,872	116,082	-	-	-	-	-	-	-	20,385,954	20,385,954	-	
28			Line	239,382	156,236,494	3,183	-	-	-	-	-	-	-	156,479,058	156,479,059	(0)	
29			Sub	-	31,312,982	-	-	-	-	-	-	-	-	31,312,982	31,312,982	-	
30			**Total**	**239,382**	**207,819,348**	**119,265**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**208,177,994**	**208,177,995**	**(0)**	**0%**
31	5/1/2009	**CAPX2020 - La Crosse Local**															
32			Land	-	10,696,845	(217,124)	-	-	-	-	-	-	-	10,479,721	10,479,721	(0)	
33			Line	-	62,212,980	811,000	38,133	(165,645)	-	-	-	-	-	62,896,468	62,210,862	685,606	
34			Sub	-	2,930,368	-	-	-	-	-	-	-	-	2,930,368	2,930,368	-	
35			**Total**	**-**	**75,840,193**	**593,876**	**38,133**	**(165,645)**	**-**	**-**	**-**	**-**	**-**	**76,306,557**	**75,620,951**	**685,606**	**1%**
36	5/1/2009	**CAPX2020 - La Crosse MISO**															
37			Land	-	6,901,161	(34,023)	-	-	-	-	-	-	-	6,867,138	6,867,138	(0)	
38			Line	-	54,082,174	137,495	-	-	-	-	-	-	-	54,219,669	54,081,261	138,408	
39			Sub	-	14,098,404	-	-	-	-	-	-	-	-	14,098,404	14,098,404	-	
40			**Total**	**-**	**75,081,739**	**103,472**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**75,185,211**	**75,046,803**	**138,408**	**0%**
41	5/1/2009	**CAPX2020 - La Crosse MISO - WI**															
42			Land	-	9,422,588	187,858	107,496	9,964	-	-	-	-	-	9,727,906	9,511,360	216,546	
43			Line	-	107,908,072	156,837	162,260	26,385	-	-	-	-	-	108,253,554	108,458,965	(205,411)	
44			Sub	-	18,406,318	574	(5,723)	-	-	-	-	-	-	18,401,169	18,406,318	(5,149)	
45			**Total**	**-**	**135,736,978**	**345,269**	**264,032**	**36,350**	**-**	**-**	**-**	**-**	**-**	**136,382,629**	**136,376,643**	**5,986**	**0%**
46	1/1/2019	**Huntley - Wilmarth**															
47			Land	-	-	693,343	1,826,017	263,806	1,769,021	-	-	-	-	4,552,187	5,144,249	(592,062)	
48			Line	148,058	1,648,866	1,700,375	27,922,985	15,906,083	1,321,189	-	-	-	-	48,647,556	65,546,990	(16,899,434)	
49			Sub	-	-	(16,460)	1,001,233	690,090	-	-	-	-	-	1,674,864	-	1,674,864	
50			**Total**	**148,058**	**1,648,866**	**2,377,258**	**30,750,236**	**16,859,980**	**3,090,209**	**-**	**-**	**-**	**-**	**54,874,607**	**70,691,239**	**(15,816,632)**	**-22%**
51	1/1/2022	**LaCrosse - Madison**															
52			Land	-	10,142,337	4,580,079	666,493	437,574	1,016,147	685,606	-	-	-	17,528,236	12,875,195	4,653,041	
53			Line	1,190,165	146,090,293	7,121,551	609,087	(3,536,024)	(213,531)	-	-	-	-	151,261,541	153,988,955	(2,727,415)	
54			Sub	2	4,730,184	127,562	62,708	-	-	-	-	-	-	4,920,456	4,741,932	178,524	
55			**Total**	**1,190,168**	**160,962,814**	**11,829,192**	**1,338,288**	**(3,098,451)**	**802,616**	**685,606**	**-**	**-**	**-**	**173,710,232**	**171,606,083**	**2,104,149**	**1%**
56		**Total**															
57			Capital	530,088	20,076,540	13,503,147	14,547,485	19,458,876	81,779,182	120,476,241	98,197,516	4,230,379	54,295,476	427,094,929	49,779,110	377,315,819	
58			Land	-	99,582,971	13,910,915	2,600,006	711,344	2,785,168	685,606	-	-	-	120,276,010	115,998,486	4,277,524	
59			Line	6,091,725	932,144,808	10,024,684	28,732,465	12,230,800	1,107,657	-	-	-	-	990,332,138	1,009,342,150	(19,010,012)	
60			Sub	43,085	129,540,184	120,180	1,058,218	690,090	-	-	-	-	-	131,451,758	129,580,873	1,870,885	
61			**Total**	**6,664,898**	**1,181,344,503**	**37,558,926**	**46,938,174**	**33,091,110**	**85,672,007**	**121,161,847**	**98,197,516**	**4,230,379**	**54,295,476**	**1,669,154,835**	**1,304,700,620**	**364,454,216**	**28%**

Line No:	Eligibility Date	NSPM Rider Project	NSPM Rider Sub Project	Pre Eligible AFUDC	CWIP Expenditures with Internal Labor									Total	Previous Filing Expenditures	Dollar Variance	% Variance
					Pre-2019	2019	2020	2021	2022	2023	2024	2025	2026				
1	1/1/2017	**AGIS - ADMS**															
2			Capital	370,966	21,257,254	9,020,265	9,125,540	5,992,215	1,974,866	3,000,700	2,669,113	4,331,681	-	57,742,600	54,530,036	3,212,564	
3			**Total**	**370,966**	**21,257,254**	**9,020,265**	**9,125,540**	**5,992,215**	**1,974,866**	**3,000,700**	**2,669,113**	**4,331,681**	**-**	**57,742,600**	**54,530,036**	**3,212,564**	**6%**
4	12/1/2020	**AGIS - AMI**															
5			Capital	1,332	1,460,149	307,792	4,377,321	10,887,693	81,086,620	117,672,163	99,431,495	-	-	315,224,564	-	315,224,564	
6			**Total**	**1,332**	**1,460,149**	**307,792**	**4,377,321**	**10,887,693**	**81,086,620**	**117,672,163**	**99,431,495**	**-**	**-**	**315,224,564**	**-**	**315,224,564**	**100%**
7	12/1/2020	**AGIS - FAN**															
8			Capital	69,764	369,731	1,715,071	1,632,688	5,903,913	9,118,356	15,125,492	8,617,724	759,930	60,883,443	104,196,111	-	104,196,111	
9			**Total**	**69,764**	**369,731**	**1,715,071**	**1,632,688**	**5,903,913**	**9,118,356**	**15,125,492**	**8,617,724**	**759,930**	**60,883,443**	**104,196,111**	**-**	**104,196,111**	**100%**
10	12/1/2020	**AGIS - LoadSeer**															
11			Capital	-	-	-	2,717,340	196,902	-	-	-	-	-	2,914,241	-	2,914,241	
12			**Total**	**-**	**-**	**-**	**2,717,340**	**196,902**	**-**	**-**	**-**	**-**	**-**	**2,914,241**	**-**	**2,914,241**	**100%**
13	1/1/2022	**AGIS - TOU Pilot**															
14			Capital	88,026	57,589	5,139,134	438,761	(838)	-	-	-	-	-	5,722,672	-	5,722,672	
15			**Total**	**88,026**	**57,589**	**5,139,134**	**438,761**	**(838)**	**-**	**-**	**-**	**-**	**-**	**5,722,672**	**-**	**5,722,672**	**100%**
16	1/1/2016	**Big Stone-Brookings**															
17			Land	-	3,550,920	-	-	-	-	-	-	-	-	3,550,920	3,550,920	-	
18			Line	421,972	52,892,775	8,396	1,582	-	-	-	-	-	-	53,324,726	53,323,143	1,582	
19			Sub	4,225	7,017,518	8,505	-	-	-	-	-	-	-	7,030,248	7,030,062	185	
20			**Total**	**426,197**	**63,461,213**	**16,901**	**1,582**	**-**	**-**	**-**	**-**	**-**	**-**	**63,905,893**	**63,904,125**	**1,768**	**0%**
21	1/1/2012	**CAPX2020 - Brookings**															
22			Land	-	38,636,001	8,584,701	-	-	-	-	-	-	-	47,220,702	47,220,702	-	
23			Line	4,092,148	360,201,112	(2,582)	-	-	-	-	-	-	-	364,290,678	364,293,260	(2,582)	
24			Sub	38,858	72,517,676	-	-	-	-	-	-	-	-	72,556,534	72,556,534	-	
25			**Total**	**4,131,006**	**471,354,789**	**8,582,119**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**484,067,914**	**484,070,495**	**(2,582)**	**0%**
26	5/1/2009	**CAPX2020 - Fargo**															
27			Land	-	20,385,627	116,082	-	-	-	-	-	-	-	20,501,709	20,501,709	-	
28			Line	239,382	168,373,438	3,183	-	-	-	-	-	-	-	168,616,002	168,616,002	-	
29			Sub	-	36,107,892	-	-	-	-	-	-	-	-	36,107,892	36,107,892	-	
30			**Total**	**239,382**	**224,866,956**	**119,265**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**225,225,603**	**225,225,603**	**-**	**0%**
31	5/1/2009	**CAPX2020 - La Crosse Local**															
32			Land	-	10,945,700	(213,893)	-	-	-	-	-	-	-	10,731,807	10,731,807	-	
33			Line	-	64,541,805	812,649	36,484	(165,645)	-	-	-	-	-	65,225,294	64,542,602	682,692	
34			Sub	-	4,169,261	-	-	-	-	-	-	-	-	4,169,261	4,169,261	-	
35			**Total**	**-**	**79,656,766**	**598,756**	**36,484**	**(165,645)**	**-**	**-**	**-**	**-**	**-**	**80,126,361**	**79,443,669**	**682,692**	**1%**
36	5/1/2009	**CAPX2020 - La Crosse MISO**															
37			Land	-	6,971,976	(34,023)	-	-	-	-	-	-	-	6,937,953	6,937,953	-	
38			Line	-	57,340,079	137,495	-	-	-	-	-	-	-	57,477,574	57,339,166	138,408	
39			Sub	-	16,942,687	-	-	-	-	-	-	-	-	16,942,687	16,942,687	-	
40			**Total**	**-**	**81,254,741**	**103,472**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**81,358,213**	**81,219,805**	**138,408**	**0%**
41	5/1/2009	**CAPX2020 - La Crosse MISO - WI**															
42			Land	-	9,605,109	196,377	111,300	3,183	-	-	-	-	-	9,915,969	9,702,467	213,502	
43			Line	-	114,198,068	158,897	160,200	26,385	-	-	-	-	-	114,543,550	114,774,171	(230,621)	
44			Sub	-	23,047,396	574	(5,723)	-	-	-	-	-	-	23,042,247	23,047,396	(5,149)	
45			**Total**	**-**	**146,850,573**	**355,848**	**265,776**	**29,568**	**-**	**-**	**-**	**-**	**-**	**147,501,766**	**147,524,034**	**(22,268)**	**0%**
46	1/1/2019	**Huntley - Wilmarth**															
47			Land	-	-	724,925	1,858,399	284,898	1,821,999	-	-	-	-	4,690,221	5,460,508	(770,287)	
48			Line	148,058	1,648,866	1,395,326	29,268,847	16,659,115	1,395,999	-	-	-	-	50,516,211	68,909,056	(18,392,845)	
49			Sub	-	-	10,778	1,382,297	1,478,396	-	-	-	-	-	2,871,471	-	2,871,471	
50			**Total**	**148,058**	**1,648,866**	**2,131,029**	**32,509,543**	**18,422,408**	**3,217,998**	**-**	**-**	**-**	**-**	**58,077,903**	**74,369,564**	**(16,291,661)**	**-22%**
51	1/1/2022	**LaCrosse - Madison**															
52			Land	-	10,164,304	4,580,079	666,493	443,596	1,031,552	696,000	-	-	-	17,582,025	12,979,961	4,602,063	
53			Line	1,190,165	146,970,825	7,126,252	609,540	(3,548,645)	(222,000)	-	-	-	-	152,126,137	154,961,578	(2,835,441)	
54			Sub	2	6,441,740	98,132	92,394	-	-	-	-	-	-	6,632,269	6,472,683	159,586	
55			**Total**	**1,190,168**	**163,576,870**	**11,804,462**	**1,368,427**	**(3,105,049)**	**809,552**	**696,000**	**-**	**-**	**-**	**176,340,430**	**174,414,222**	**1,926,208**	**1%**
56		**Total**															
57			Capital	530,088	23,144,723	16,182,262	18,291,650	22,979,884	92,179,841	135,798,355	110,718,332	5,091,611	60,883,443	485,800,188	54,530,036	431,270,152	
58			Land	-	100,259,637	13,954,248	2,636,192	731,677	2,853,551	696,000	-	-	-	121,131,304	117,086,026	4,045,278	
59			Line	6,091,725	966,166,968	9,639,617	30,076,652	12,971,210	1,173,999	-	-	-	-	1,026,120,170	1,046,758,976	(20,638,806)	
60			Sub	43,085	166,244,170	117,988	1,468,968	1,478,396	-	-	-	-	-	169,352,607	166,326,514	3,026,093	
61			**Total**	**6,664,898**	**1,255,815,497**	**39,894,114**	**52,473,463**	**38,161,167**	**96,207,391**	**136,494,355**	**110,718,332**	**5,091,611**	**60,883,443**	**1,802,404,270**	**1,384,701,553**	**417,702,718**	**30%**

Annual Filing View Tracker Summary

Amounts in dollars		2019	2020	2021	2022	2023
		Actual	Actual	Mixed	Forecast	Forecast
Line No:						
1	AGIS - ADMS	1,979,777	2,799,047	5,185,468	5,895,245	5,940,888
2	AGIS - AMI	-	1,210,039	4,639,342	15,708,542	35,101,489
3	AGIS - FAN	-	234,981	1,239,549	1,925,235	3,185,952
4	AGIS - LoadSeer	-	230,108	740,129	672,353	625,508
5	AGIS - TOU Pilot	-	-	-	699,701	667,758
6	Big Stone-Brookings	4,095,135	3,973,954	3,850,967	3,752,627	3,664,659
7	CAPX2020 - Brookings	32,887,354	32,127,705	31,300,336	30,662,824	29,949,570
8	CAPX2020 - Fargo	14,818,201	14,355,718	13,929,370	13,589,185	13,215,609
9	CAPX2020 - La Crosse Local	4,139,767	4,156,103	3,992,695	3,957,322	3,858,452
10	CAPX2020 - La Crosse MISO	5,397,139	5,255,055	5,119,584	5,015,570	4,898,618
11	CAPX2020 - La Crosse MISO - WI	10,043,647	9,741,083	9,458,162	9,229,727	8,977,953
12	Huntley - Wilmarth	200,312	1,106,219	2,990,627	4,843,143	4,759,949
13	LaCrosse - Madison	14,923,365	14,915,964	14,288,700	13,845,072	13,488,580
14	**Projects**	88,484,696	90,105,977	96,734,930	109,796,546	128,334,985
15	MISO RECB Sch.26/26a	(8,497,508)	510,576	(3,995,005)	(9,607,189)	(10,858,596)
16	Base Rates	(1,937,000)	(1,937,000)	(1,937,000)	-	-
17	TCR True-up Carryover	1,036,546	(7,482,299)	(3,753,258)	4,346,913	7,956,886
18	**Revenue Requirement (RR)**	**79,086,734**	**81,197,254**	**87,049,667**	**104,536,270**	**125,433,275**
19	**Revenue Collections (RC)**	86,569,032	84,950,513	82,702,754	96,579,384	105,286,448
20	Monthly RR - RC	-	-	-	-	-
21	Balance (RR - RC + Cumulative CC)	(7,482,299)	(3,753,258)	4,346,913	7,956,886	20,146,828

		Total Company			MN Jurisdiction			
	Rate Analysis	2017	2018	2019	2017	2018	2019	
1	Average Balances:							
2	Plant Investment	-	2,217	4,434	-	1,936	3,873	
3	Depreciation Reserve	-	18	480	-	16	420	
4	CWIP	3,967	2,060	-	3,465	1,799	-	
5	Accumulated Deferred Taxes	68	434	772	59	379	674	
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	3,899	3,825	3,181	3,405	3,341	2,779	
7								
8	Revenues:							
9	Interchange Agreement offset = -line 40 x line 52 x line 53				-	-	-	
10								
11	Expenses:							
12	Book Depreciation	-	37	887	-	32	775	
13	Annual Deferred Tax	40	691	(14)	35	604	(12)	
14	ITC Flow Thru	-	-	-	-	-	-	
15	Property Taxes	-	-	-	-	-	-	
16	subtotal expense = lines 12 thru 15	40	728	873	35	636	762	
17								
18	Tax Preference Items:							
19	Tax Depreciation & Removal Expense	-	1,613	740	-	1,409	647	
20	Tax Credits (enter as negative)	-	-	-	-	-	-	
21	Avoided Tax Interest	-	-	-	-	-	-	
22					-	-	-	
23	AFUDC	263	269	-	230	235	-	
24								
25	Returns:							
26	Debt Return = line 6 x (line 44 + line 45)	88	86	72	77	76	63	
27	Equity Return = line 6 x (line 46 + line 47)	188	185	154	164	161	134	
28								
29	Tax Calculations:							
30	Equity Return = line 27	188	185	154	164	161	134	
31	Taxable Expenses = lines 12 thru 14	40	728	873	35	636	762	
32	plus Tax Additions = line 21	-	-	-	-	-	-	
33	less Tax Deductions = (line 19 + line 23)	(263)	(1,882)	(740)	(230)	(1,644)	(647)	
34	subtotal	(35)	(969)	286	(30)	(847)	250	
35	Tax gross-up factor = t / (1-t) from line 50	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611	
36	Current Income Tax Requirement = line 34 x line 35	(24)	(684)	202	(21)	(597)	176	
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-	
38	Total Current Tax Revenue Requirement = line 36+ line 37	(24)	(684)	202	(21)	(597)	176	
39								
40	Total Capital Revenue Requirements	29	46	1,300	25	40	1,136	
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9							
42	O&M Expense	-	-	-	-	-	-	
43	Total Revenue Requirements	29	46	1,300	25	40	1,136	(1)

	Capital Structure	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost
44	Long Term Debt	2.2100%	2.2100%	2.1800%	2.2100%	2.2100%	2.1800%
45	Short Term Debt	0.0500%	0.0500%	0.0700%	0.0500%	0.0500%	0.0700%
46	Preferred Stock	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
47	Common Equity	4.8300%	4.8300%	4.8300%	4.8300%	4.8300%	4.8300%
48	Required Rate of Return	7.0900%	7.0900%	7.0800%	7.0900%	7.0900%	7.0800%
49	PT Rate	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
50	Tax Rate (MN)	41.3700%	41.3700%	41.3700%	41.3700%	41.3700%	41.3700%
51	MN JUR Electric Intangible Composite	87.3467%	87.3467%	87.3467%	87.3467%	87.3467%	87.3467%
52	IA Demand	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

(1) Revenue Requirements are spread evenly across 12 months in Attachment 9

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
ADMS - GIS Model Improvements Base Rates Removal
(000's)

		Total Company			MN Jurisdiction		
	Rate Analysis	2017	2018	2019	2017	2018	2019
1	Average Balances:						
2	Plant Investment	1,993	2,989	3,736	1,741	2,611	3,264
3	Depreciation Reserve	401	888	1,553	350	776	1,356
4	CWIP	-	-	-	-	-	-
5	Accumulated Deferred Taxes	356	493	534	311	430	466
6	Average Rate Base = line 2 - line 3 + line 4 - line 5	1,236	1,608	1,649	1,080	1,405	1,441
7							
8	Revenues:						
9	Interchange Agreement offset = -line 40 x line 52 x line 53				-	-	-
10							
11	Expenses:						
12	Book Depreciation	393	592	744	343	517	650
13	Annual Deferred Tax	165	109	(27)	144	96	(24)
14	ITC Flow Thru	-	-	-	-	-	-
15	Property Taxes	-	-	-	-	-	-
16	subtotal expense = lines 12 thru 15	558	702	718	487	613	627
17							
18	Tax Preference Items:						
19	Tax Depreciation & Removal Expense	795	859	678	694	750	592
20	Tax Credits (enter as negative)	-	-	-	-	-	-
21	Avoided Tax Interest	-	-	-	-	-	-
22					-	-	-
23	AFUDC	1	1	1	1	1	1
24							
25	Returns:						
26	Debt Return = line 6 x (line 44 + line 45)	28	36	37	24	32	32
27	Equity Return = line 6 x (line 46 + line 47)	60	78	80	52	68	70
28							
29	Tax Calculations:						
30	Equity Return = line 27	60	78	80	52	68	70
31	Taxable Expenses = lines 12 thru 14	558	702	718	487	613	627
32	plus Tax Additions = line 21	-	-	-	-	-	-
33	less Tax Deductions = (line 19 + line 23)	(796)	(860)	(678)	(696)	(751)	(592)
34	subtotal	(179)	(81)	119	(157)	(71)	104
35	Tax gross-up factor = t / (1-t) from line 50	0.705611	0.705611	0.705611	0.705611	0.705611	0.705611
36	Current Income Tax Requirement = line 34 x line 35	(126)	(57)	84	(110)	(50)	73
37	Tax Credit Revenue Requirement = line 20 x line 35 + line 20	-	-	-	-	-	-
38	Total Current Tax Revenue Requirement = line 36+ line 37	(126)	(57)	84	(110)	(50)	73
39							
40	Total Capital Revenue Requirements	517	757	918	452	661	801
41	= line 16 + line 26 + line 27 + line 38 - line 23 + line 9						
42	O&M Expense	-	-	-	-	-	-
43	Total Revenue Requirements	517	757	918	452	661	801
	Capital Structure	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost	Weighted Cost
44	Long Term Debt	2.2100%	2.2100%	2.1800%	2.2100%	2.2100%	2.1800%
45	Short Term Debt	0.0500%	0.0500%	0.0700%	0.0500%	0.0500%	0.0700%
46	Preferred Stock	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
47	Common Equity	4.8300%	4.8300%	4.8300%	4.8300%	4.8300%	4.8300%
48	Required Rate of Return	7.0900%	7.0900%	7.0800%	7.0900%	7.0900%	7.0800%
49	PT Rate	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%	0.0000%
50	Tax Rate (MN)	41.3700%	41.3700%	41.3700%	41.3700%	41.3700%	41.3700%
51	MN JUR Energy	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%
52	MN JUR Electric Intangible Composite	87.3467%	87.3467%	87.3467%	87.3467%	87.3467%	87.3467%
53	IA Demand	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%	100.0000%

(1) Revenue Requirements are spread evenly across 12 months in Attachment 9

Monthly Revenue Requirement Filing Summary

	Amounts in dollars	2018	2019 Monthly Details												
		2018	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
Line #:		Carryover	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
1	AGIS - ADMS		123,802	128,696	133,436	138,584	155,182	146,256	223,022	176,285	179,794	183,462	186,616	204,641	1,979,777
2	AGIS - AMI		-	-	-	-	-	-	-	-	-	-	-	-	-
3	AGIS - FAN		-	-	-	-	-	-	-	-	-	-	-	-	-
4	AGIS - LoadSeer		-	-	-	-	-	-	-	-	-	-	-	-	-
5	AGIS - TOU Pilot		-	-	-	-	-	-	-	-	-	-	-	-	-
6	Big Stone-Brookings		345,155	344,421	343,672	342,921	342,133	341,589	341,098	340,362	339,596	338,829	338,063	337,296	4,095,135
7	CAPX2020 - Brookings		2,751,523	2,769,044	2,763,160	2,757,276	2,751,393	2,745,509	2,739,625	2,733,742	2,727,851	2,721,960	2,716,077	2,710,193	32,887,354
8	CAPX2020 - Fargo		1,250,597	1,248,030	1,245,465	1,242,468	1,239,465	1,236,462	1,233,459	1,230,457	1,227,454	1,224,451	1,221,448	1,218,445	14,818,201
9	CAPX2020 - La Crosse Local		349,592	348,173	347,341	346,510	345,679	344,848	344,017	343,185	342,354	341,524	342,579	343,965	4,139,767
10	CAPX2020 - La Crosse MISO		455,270	454,180	453,187	452,194	451,201	450,207	449,214	448,221	447,228	446,235	445,241	444,761	5,397,139
11	CAPX2020 - La Crosse MISO - WI		847,102	845,086	843,115	841,087	839,028	837,445	836,444	835,122	833,084	830,883	828,793	826,456	10,043,647
12	Huntley - Wilmarth		13,603	16,792	(8,757)	17,090	17,828	18,220	18,641	19,275	19,873	20,733	22,398	24,617	200,312
13	LaCrosse - Madison		1,260,378	1,268,282	1,262,799	1,256,927	1,251,638	1,246,080	1,241,429	1,236,487	1,230,094	1,223,655	1,223,307	1,222,290	14,923,365
14	**Projects**		7,397,021	7,422,705	7,383,417	7,395,058	7,393,548	7,366,616	7,426,950	7,363,136	7,347,328	7,331,733	7,324,522	7,332,662	88,484,696
15	MISO RECB Sch.26/26a		(1,048,965)	(609,927)	(865,791)	(612,104)	(546,251)	(609,730)	(580,000)	(431,486)	(371,812)	(1,325,457)	(807,180)	(688,807)	(8,497,508)
16	Base Rates		(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(1,937,000)
17	TCR True-up Carryover		1,036,546												1,036,546
18	**Revenue Requirement (RR)**		**7,223,185**	**6,651,362**	**6,356,210**	**6,621,538**	**6,685,879**	**6,595,469**	**6,685,534**	**6,770,234**	**6,814,100**	**5,844,860**	**6,355,926**	**6,482,438**	**79,086,734**
19	**Revenue Collections (RC)**		7,294,988	6,484,043	7,315,226	6,610,227	6,560,614	6,823,629	8,438,921	8,481,413	7,095,489	7,595,978	6,402,255	7,466,251	86,569,032
20	Monthly RR - RC		(71,803)	167,319	(959,016)	11,310	125,266	(228,160)	(1,753,387)	(1,711,179)	(281,389)	(1,751,118)	(46,329)	(983,813)	
21	Balance (RR - RC + Cumulative CC)	1,036,546	(71,803)	95,516	(863,500)	(852,190)	(726,924)	(955,084)	(2,708,471)	(4,419,649)	(4,701,039)	(6,452,157)	(6,498,486)	(7,482,299)	(7,482,299)

Monthly Revenue Requirement Filing Summary

Line #	Amounts in dollars	2020 Monthly Details												
		Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
1	AGIS - ADMS	199,410	217,224	217,974	232,610	207,934	220,197	236,244	245,169	272,455	253,358	259,847	236,624	2,799,047
2	AGIS - AMI	38,246	72,917	87,828	140,658	72,019	104,114	63,923	75,072	101,547	92,035	197,950	163,730	1,210,039
3	AGIS - FAN	12,773	15,838	23,464	17,356	12,944	15,638	18,013	18,824	23,482	20,791	24,977	30,880	234,981
4	AGIS - LoadSeer	1,160	5,631	13,185	13,447	11,965	12,220	13,329	22,889	36,322	30,803	23,315	45,843	230,108
5	AGIS - TOU Pilot	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Big Stone-Brookings	335,262	334,405	333,778	333,030	332,290	331,542	330,802	330,058	329,311	328,571	327,823	327,083	3,973,954
7	CAPX2020 - Brookings	2,704,548	2,699,255	2,694,662	2,689,703	2,684,765	2,679,806	2,674,869	2,669,921	2,664,961	2,660,024	2,655,064	2,650,127	32,127,705
8	CAPX2020 - Fargo	1,211,369	1,208,328	1,205,911	1,203,166	1,200,442	1,197,698	1,194,973	1,192,239	1,189,495	1,186,770	1,184,026	1,181,302	14,355,718
9	CAPX2020 - La Crosse Local	350,669	349,751	349,058	348,247	347,450	346,748	346,048	345,241	344,431	343,628	342,817	342,014	4,156,103
10	CAPX2020 - La Crosse MISO	442,871	441,870	441,077	440,175	439,279	438,377	437,482	436,583	435,682	434,786	433,884	432,989	5,255,055
11	CAPX2020 - La Crosse MISO - WI	822,207	820,585	818,793	816,750	814,732	812,748	810,801	808,848	806,883	804,910	802,913	800,913	9,741,083
12	Huntley - Wilmarth	13,089	15,845	18,447	22,473	30,936	55,482	89,490	125,756	155,733	176,165	194,075	208,727	1,106,219
13	LaCrosse - Madison	1,255,605	1,253,358	1,251,748	1,248,948	1,246,403	1,243,835	1,241,446	1,239,031	1,236,780	1,235,078	1,233,043	1,230,690	14,915,964
14	**Projects**	7,387,208	7,435,007	7,455,924	7,506,562	7,401,158	7,458,405	7,457,421	7,509,633	7,597,083	7,566,918	7,679,735	7,650,921	90,105,977
15	MISO RECB Sch.26/26a	(68,517)	(295,282)	(247,066)	344,063	(184,050)	232,100	1,290,395	299,554	(378,241)	(71,596)	(104,417)	(306,367)	510,576
16	Base Rates	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(1,937,000)
17	TCR True-up Carryover	(7,482,299)												(7,482,299)
18	**Revenue Requirement (RR)**	**(325,024)**	**6,978,308**	**7,047,442**	**7,689,208**	**7,055,692**	**7,529,088**	**8,586,400**	**7,647,770**	**7,057,426**	**7,333,906**	**7,413,902**	**7,183,137**	**81,197,254**
19	**Revenue Collections (RC)**	7,995,677	6,809,306	7,231,038	6,235,727	5,694,281	7,263,408	8,714,843	8,026,844	7,502,125	6,701,121	6,009,199	6,766,944	84,950,513
20	Monthly RR - RC	(8,320,701)	169,002	(183,596)	1,453,481	1,361,411	265,680	(128,443)	(379,074)	(444,700)	632,784	1,404,703	416,193	
21	Balance (RR - RC + Cumulative CC)	(8,320,701)	(8,151,699)	(8,335,295)	(6,881,814)	(5,520,403)	(5,254,722)	(5,383,165)	(5,762,240)	(6,206,939)	(5,574,155)	(4,169,451)	(3,753,258)	(3,753,258)

Monthly Revenue Requirement Filing Summary

Line #	Amounts in dollars	**2021 Monthly Details**												
		Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
		Mixed	Mixed	Mixed	Mixed	Mixed	Mixed	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
1	AGIS - ADMS	157,549	173,414	173,608	342,611	501,771	481,345	554,869	553,695	556,348	559,257	560,950	570,051	5,185,468
2	AGIS - AMI	146,580	202,187	145,274	197,413	136,428	145,970	545,305	542,563	556,299	695,668	633,644	692,012	4,639,342
3	AGIS - FAN	12,454	26,868	26,883	30,161	45,616	55,629	155,074	159,473	165,666	176,030	185,186	200,509	1,239,549
4	AGIS - LoadSeer	59,544	237,521	(107,692)	61,621	61,383	59,137	62,790	61,999	61,333	61,056	60,744	60,693	740,129
5	AGIS - TOU Pilot	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Big Stone-Brookings	324,880	324,159	323,438	322,717	321,996	321,274	320,553	319,832	319,111	318,390	317,669	316,947	3,850,967
7	CAPX2020 - Brookings	2,633,680	2,629,077	2,624,473	2,619,870	2,615,266	2,610,663	2,606,060	2,601,456	2,596,853	2,592,250	2,587,646	2,583,043	31,300,336
8	CAPX2020 - Fargo	1,174,205	1,171,765	1,169,324	1,166,883	1,164,442	1,162,001	1,159,560	1,157,119	1,154,679	1,152,238	1,149,797	1,147,356	13,929,370
9	CAPX2020 - La Crosse Local	337,468	336,695	335,923	335,150	334,378	333,147	331,917	331,146	330,375	329,603	328,832	328,061	3,992,695
10	CAPX2020 - La Crosse MISO	430,754	430,005	429,255	428,506	427,756	427,007	426,257	425,508	424,758	424,009	423,259	422,510	5,119,584
11	CAPX2020 - La Crosse MISO - WI	797,019	795,472	793,933	792,298	790,680	789,051	787,404	785,756	784,109	782,461	780,814	779,166	9,458,162
12	Huntley - Wilmarth	197,398	192,037	211,325	223,624	234,007	246,134	255,760	266,386	276,381	283,759	289,297	314,518	2,990,627
13	LaCrosse - Madison	1,226,257	1,213,651	1,198,709	1,196,770	1,194,048	1,191,309	1,188,568	1,185,852	1,179,352	1,173,437	1,171,578	1,169,169	14,288,700
14	**Projects**	7,497,790	7,732,851	7,324,452	7,717,623	7,827,771	7,822,668	8,394,118	8,390,785	8,405,263	8,548,158	8,489,416	8,584,035	96,734,930
15	MISO RECB Sch.26/26a	(1,548,197)	(29,652)	268,406	(1,042,665)	50,016	898,900	(19,487)	(139,116)	(306,308)	(818,493)	(761,520)	(546,889)	(3,995,005)
16	Base Rates	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(161,417)	(1,937,000)
17	TCR True-up Carryover	(3,753,258)												(3,753,258)
18	**Revenue Requirement (RR)**	**2,034,918**	**7,541,782**	**7,431,442**	**6,513,542**	**7,716,370**	**8,560,151**	**8,213,214**	**8,090,253**	**7,937,538**	**7,568,248**	**7,566,479**	**7,875,729**	**87,049,667**
19	**Revenue Collections (RC)**	6,727,066	6,144,110	7,113,200	6,266,166	5,925,856	8,045,828	8,168,969	7,967,657	6,635,662	6,421,902	6,317,550	6,968,789	82,702,754
20	Monthly RR - RC	(4,692,148)	1,397,672	318,242	247,376	1,790,515	514,324	44,246	122,595	1,301,875	1,146,346	1,248,929	906,941	
21	Balance (RR - RC + Cumulative CC)	(4,692,148)	(3,294,476)	(2,976,234)	(2,728,858)	(938,344)	(424,020)	(379,774)	(257,179)	1,044,696	2,191,043	3,439,972	4,346,913	4,346,913

Monthly Revenue Requirement Filing Summary

		2022 Monthly Details												
	Amounts in dollars	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
Line #:		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
1	AGIS - ADMS	475,788	474,621	488,477	502,602	501,177	499,266	497,366	495,321	493,132	491,104	489,166	487,224	5,895,245
2	AGIS - AMI	832,104	939,582	1,031,849	1,119,797	1,193,063	1,280,099	1,368,496	1,441,123	1,511,985	1,584,271	1,662,147	1,744,025	15,708,542
3	AGIS - FAN	135,226	138,923	142,607	146,374	151,500	157,330	161,786	166,194	171,798	178,005	184,808	190,683	1,925,235
4	AGIS - LoadSeer	57,969	57,617	57,264	56,911	56,558	56,206	55,854	55,501	55,147	54,795	54,442	54,090	672,353
5	AGIS - TOU Pilot	59,231	59,063	58,896	58,728	58,560	58,392	58,225	58,057	57,889	57,722	57,553	57,386	699,701
6	Big Stone-Brookings	316,585	315,882	315,179	314,476	313,773	313,069	312,369	311,666	310,960	310,260	309,554	308,854	3,752,627
7	CAPX2020 - Brookings	2,580,574	2,575,966	2,571,359	2,566,752	2,562,144	2,557,537	2,552,936	2,548,328	2,543,715	2,539,114	2,534,501	2,529,899	30,662,824
8	CAPX2020 - Fargo	1,145,861	1,143,419	1,140,977	1,138,535	1,136,093	1,133,651	1,131,215	1,128,773	1,126,326	1,123,889	1,121,442	1,119,005	13,589,185
9	CAPX2020 - La Crosse Local	333,301	332,660	332,019	331,379	330,738	330,097	329,457	328,816	328,175	327,535	326,893	326,253	3,957,322
10	CAPX2020 - La Crosse MISO	422,098	421,347	420,595	419,843	419,091	418,340	417,589	416,837	416,084	415,334	414,581	413,830	5,015,570
11	CAPX2020 - La Crosse MISO - WI	778,193	776,548	774,903	773,257	771,612	769,966	768,322	766,676	765,030	763,385	761,739	760,095	9,229,727
12	Huntley - Wilmarth	395,336	400,730	406,119	408,435	407,558	406,559	405,568	404,569	403,562	402,571	401,564	400,573	4,843,143
13	LaCrosse - Madison	1,166,722	1,164,859	1,162,516	1,160,172	1,157,828	1,155,484	1,153,152	1,150,808	1,147,554	1,144,336	1,141,989	1,139,652	13,845,072
14	**Projects**	8,698,988	8,801,218	8,902,759	8,997,261	9,059,695	9,135,997	9,212,333	9,272,670	9,331,358	9,392,320	9,460,379	9,531,568	109,796,546
15	MISO RECB Sch.26/26a	(1,230,897)	(1,175,672)	(904,393)	(820,222)	(820,174)	(338,068)	(316,315)	(444,148)	(623,102)	(1,093,700)	(1,020,458)	(820,039)	(9,607,189)
16	Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
17	TCR True-up Carryover	4,346,913												4,346,913
18	**Revenue Requirement (RR)**	**11,815,004**	**7,625,545**	**7,998,366**	**8,177,038**	**8,239,521**	**8,797,929**	**8,896,017**	**8,828,522**	**8,708,256**	**8,298,621**	**8,439,921**	**8,711,529**	**104,536,270**
19	**Revenue Collections (RC)**	6,969,537	6,130,916	6,523,028	5,745,158	6,315,360	9,331,475	10,860,362	10,530,678	8,586,618	8,264,140	8,167,306	9,154,807	96,579,384
20	Monthly RR - RC	4,845,467	1,494,630	1,475,337	2,431,880	1,924,161	(533,546)	(1,964,344)	(1,702,156)	121,638	34,481	272,614	(443,277)	
21	Balance (RR - RC + Cumulative CC)	4,845,467	6,340,097	7,815,435	10,247,315	12,171,476	11,637,931	9,673,586	7,971,430	8,093,068	8,127,549	8,400,163	7,956,886	7,956,886

Monthly Revenue Requirement Filing Summary

		2023 Monthly Details												
	Amounts in dollars	Jan - 2023	Feb - 2023	Mar - 2023	Apr - 2023	May - 2023	Jun - 2023	Jul - 2023	Aug - 2023	Sep - 2023	Oct - 2023	Nov - 2023	Dec - 2023	2023
		Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast	Forecast
Line #:														
1	AGIS - ADMS	502,225	500,568	498,923	497,400	496,022	494,632	493,254	492,377	492,000	491,636	491,094	490,758	5,940,888
2	AGIS - AMI	2,275,418	2,397,402	2,535,619	2,665,007	2,775,988	2,885,083	2,995,519	3,105,668	3,213,943	3,323,559	3,418,384	3,509,901	35,101,489
3	AGIS - FAN	231,686	238,005	242,943	248,555	254,573	260,859	267,159	273,123	279,060	286,712	294,665	308,612	3,185,952
4	AGIS - LoadSeer	53,707	53,419	53,132	52,844	52,557	52,269	51,982	51,694	51,407	51,120	50,832	50,545	625,508
5	AGIS - TOU Pilot	56,504	56,348	56,192	56,036	55,880	55,724	55,569	55,413	55,257	55,101	54,945	54,789	667,758
6	Big Stone-Brookings	308,293	307,765	307,237	306,709	306,181	305,652	305,124	304,596	304,068	303,540	303,011	302,483	3,664,659
7	CAPX2020 - Brookings	2,521,086	2,516,483	2,511,891	2,507,288	2,502,696	2,498,093	2,493,501	2,488,904	2,484,301	2,479,709	2,475,106	2,470,514	29,949,570
8	CAPX2020 - Fargo	1,114,705	1,112,263	1,109,832	1,107,390	1,104,958	1,102,516	1,100,085	1,097,648	1,095,206	1,092,774	1,090,332	1,087,900	13,215,609
9	CAPX2020 - La Crosse Local	325,062	324,421	323,781	323,139	322,499	321,858	321,218	320,577	319,935	319,295	318,654	318,014	3,858,452
10	CAPX2020 - La Crosse MISO	412,368	411,613	410,859	410,104	409,350	408,595	407,841	407,087	406,331	405,578	404,822	404,069	4,898,618
11	CAPX2020 - La Crosse MISO - WI	757,195	755,552	753,911	752,268	750,626	748,984	747,342	745,700	744,057	742,415	740,772	739,131	8,977,953
12	Huntley - Wilmarth	401,850	400,901	399,965	399,015	398,079	397,130	396,194	395,251	394,302	393,366	392,416	391,480	4,759,949
13	LaCrosse - Madison	1,136,754	1,134,435	1,132,136	1,129,816	1,127,517	1,125,197	1,122,898	1,120,588	1,118,269	1,115,969	1,113,650	1,111,350	13,488,580
14	**Projects**	10,096,854	10,209,175	10,336,419	10,455,571	10,556,926	10,656,592	10,757,684	10,858,625	10,958,135	11,060,773	11,148,684	11,239,547	128,334,985
15	MISO RECB Sch.26/26a	(1,334,217)	(1,284,564)	(1,000,131)	(896,263)	(916,490)	(428,821)	(403,566)	(542,700)	(728,975)	(1,211,233)	(1,151,817)	(959,819)	(10,858,596)
16	Base Rates	-	-	-	-	-	-	-	-	-	-	-	-	-
17	TCR True-up Carryover	7,956,886												7,956,886
18	**Revenue Requirement (RR)**	**16,719,523**	**8,924,611**	**9,336,288**	**9,559,308**	**9,640,436**	**10,227,771**	**10,354,118**	**10,315,925**	**10,229,160**	**9,849,540**	**9,996,867**	**10,279,728**	**125,433,275**
19	**Revenue Collections (RC)**	9,318,460	7,825,489	8,734,339	7,512,998	8,062,126	9,211,114	10,690,999	10,363,021	8,420,800	8,102,118	8,039,313	9,005,670	105,286,448
20	Monthly RR - RC	7,401,063	1,099,122	601,949	2,046,309	1,578,310	1,016,657	(336,881)	(47,095)	1,808,360	1,747,421	1,957,554	1,274,058	
21	Balance (RR - RC + Cumulative CC)	7,401,063	8,500,185	9,102,135	11,148,444	12,726,754	13,743,411	13,406,530	13,359,434	15,167,794	16,915,215	18,872,770	20,146,828	20,146,828

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Sales and Revenue Calculation

Docket No. E002/M-21-____
Petition
Attachment 10

	Forecast Revenue (2)					Sales by Customer Group (3)					kW Demand
		Customer Groups					Customer Groups				
	Total Revenue	Residential	Commercial Non-Demand	Demand	Street Lighting	Retail Sales	Residential	Commercial Non-Demand	Demand	Street Lighting	Demand Group
Adjustment Factors											
2019-2020 TCR Rates - Provisional Rates		**$ 0.003607**	**$ 0.003185**	**$ 0.982000**	**$ -**						
2022 TCR Rates - Proposed Rates		**$ 0.005783**	**$ 0.004545**	**$ 1.081000**	**$ -**						
Jul 2021	8,168,969	3,457,272	234,895	4,476,802	-	2,796,312,903	958,489,658	73,750,358	1,757,650,235	6,422,651	4,558,861
Aug 2021	7,967,657	3,275,116	228,196	4,464,346	-	2,739,583,289	907,988,843	71,647,084	1,752,759,821	7,187,541	4,546,177
Sep 2021	6,635,662	2,461,756	194,886	3,979,021	-	2,314,366,752	682,493,903	61,188,666	1,562,215,154	8,469,030	4,051,956
Oct 2021	6,421,902	2,267,895	192,266	3,961,741	-	2,255,042,103	628,748,193	60,366,241	1,555,430,698	10,496,971	4,034,359
Nov 2021	6,317,550	2,370,936	205,171	3,741,443	-	2,202,789,659	657,315,173	64,417,973	1,468,938,900	12,117,613	3,810,023
Dec 2021	6,968,789	2,873,730	227,747	3,867,312	-	2,400,522,664	796,709,167	71,506,076	1,518,356,641	13,950,779	3,938,199
Jan 2022	6,969,537	2,941,607	237,660	3,790,269	-	2,392,974,882	815,527,399	74,618,656	1,488,108,600	14,720,228	3,859,744
Feb 2022	6,130,916	2,370,631	228,384	3,531,901	-	2,127,660,597	657,230,561	71,706,127	1,386,670,037	12,053,871	3,596,641
Mar 2022	6,523,028	2,434,958	225,651	3,862,419	-	2,273,923,550	675,064,517	70,848,143	1,516,435,795	11,575,095	3,933,217
Apr 2022	5,745,158	2,056,093	193,285	3,495,779	-	2,012,799,332	570,028,528	60,686,181	1,372,488,245	9,596,378	3,559,857
May 2022	6,315,360	2,195,402	213,025	3,906,933	-	2,217,806,558	608,650,478	66,883,877	1,533,912,286	8,359,917	3,978,546
Jun 2022	9,331,475	4,531,283	305,764	4,494,427	-	2,460,901,615	783,552,365	67,274,875	1,602,967,542	7,106,833	4,157,657
Jul 2022	10,860,362	5,489,522	343,355	5,027,484	-	2,824,387,593	949,251,667	75,545,692	1,793,086,000	6,504,234	4,650,772
Aug 2022	10,530,678	5,186,816	330,634	5,013,229	-	2,764,910,903	896,907,487	72,746,745	1,788,001,598	7,255,073	4,637,584
Sep 2022	8,586,618	3,850,965	282,206	4,453,447	-	2,324,887,415	665,911,324	62,091,567	1,588,351,743	8,532,782	4,119,747
Oct 2022	8,264,140	3,564,578	277,219	4,422,343	-	2,265,198,325	616,389,023	60,994,350	1,577,258,195	10,556,757	4,090,974
Nov 2022	8,167,306	3,728,897	297,471	4,140,939	-	2,199,339,185	644,803,138	65,450,184	1,476,893,631	12,192,231	3,830,656
Dec 2022	9,154,807	4,539,557	328,910	4,286,340	-	2,400,121,716	784,982,978	72,367,343	1,528,752,077	14,019,317	3,965,162
Jan 2023	9,318,460	4,699,907	354,759	4,263,793	-	2,426,358,015	812,710,961	78,054,801	1,520,710,523	14,881,730	3,944,305
Feb 2023	7,825,489	3,784,441	308,539	3,732,510	-	2,065,502,843	654,407,887	67,885,277	1,331,224,567	11,985,112	3,452,830
Mar 2023	8,734,339	3,883,829	355,764	4,494,746	-	2,364,784,795	671,594,200	78,275,840	1,603,081,293	11,833,461	4,157,952
Apr 2023	7,512,998	3,272,025	291,783	3,949,191	-	2,048,253,891	565,800,574	64,198,619	1,408,505,469	9,749,229	3,653,276
May 2023	8,062,126	3,502,702	302,450	4,256,974	-	2,198,911,187	605,689,516	66,545,586	1,518,278,423	8,397,662	3,937,996
Jun 2023	9,211,114	4,513,321	299,016	4,398,777	-	2,422,209,610	780,446,292	65,790,066	1,568,853,457	7,119,795	4,069,174
Jul 2023	10,690,999	5,482,744	330,625	4,877,630	-	2,766,963,043	948,079,502	72,744,873	1,739,639,446	6,499,223	4,512,146
Aug 2023	10,363,021	5,180,824	317,974	4,864,223	-	2,707,938,461	895,871,377	69,961,276	1,734,857,681	7,248,127	4,499,743
Sep 2023	8,420,800	3,844,473	270,312	4,306,015	-	2,268,547,641	664,788,651	59,474,694	1,535,769,236	8,515,061	3,983,363
Oct 2023	8,102,118	3,567,916	263,585	4,270,618	-	2,208,612,074	616,966,273	57,994,427	1,523,144,441	10,506,932	3,950,618
Nov 2023	8,039,313	3,734,590	285,964	4,018,759	-	2,154,176,487	645,787,640	62,918,398	1,433,317,303	12,153,146	3,717,631
Dec 2023	9,005,670	4,547,680	314,602	4,143,387	-	2,347,334,038	786,387,763	69,219,361	1,477,766,867	13,960,048	3,832,921
Total June'22 thru May '23	**$ 106,348,798**	**$ 50,034,522**	**$ 3,778,853**	**$ 52,535,422**	**$ -**	**28,343,557,484**	**8,652,001,122**	**831,430,879**	**18,737,111,063**	**123,014,420**	**48,598,911**

		2022 Customer Group Weighting*	Retail % Weighting	Customer Groups: Residential	Commercial Non-Demand	Demand	Street Lighting	Total
Transmission Demand Allocator	D10S	75,288,280	75.15%	36.14%	3.28%	60.59%	0.00%	100.00%
Distribution Allocator without Lighting	P60 W/O Lighting	24,901,077	24.85%	70.33%	4.59%	25.08%	0.00%	100.00%
Combined Average Allocation		100,189,357	100.00%	44.63%	3.60%	51.76%	0.00%	100.00%
Sales Allocator	E99		100.00%	28.47%	2.92%	68.06%	0.55%	100.00%
Group Weighting Factor (1)	**Fixed Ratio**		**1.0000**	**1.5680**	**1.2324**	**0.7605**	**-**	**1.0000**
	MN kWh retail Sales		**28,343,557,484**	8,652,001,122	831,430,879	18,737,111,063	123,014,420	28,343,557,484
	MN kW Demand					48,598,911		
State of Mn Cost per kWh	**Total Sales/Costs**	**$**	**0.0036882**					
	MN retail Cost		**104,536,270**	50,034,522	3,778,853	52,557,597	-	106,370,972
TCR Adjustment Factor (2)			**per kWh**	**0.005783**	**0.004545**		**0.00000**	
			per kW			**1.081**		

*excludes over/under carryover

Notes:

1) The Group Weighting Factors are calculated by dividing the combined average allocation percentage for each customer group, by the corresponding sales allocation percentage for the same customer group. The transmission demand, distribution, and sales allocation percentages were established in Xcel Energy's last approved electric rate case, Docket No. E002/GR-15-826.

2) The TCR Adjustment Factors by customer group are determined by multiplying each Group Weighting Factor by the average retail cost per kWh. The average retail cost per kWh is calculated by using the Minnesota electric retail cost divided by the annual Minnesota Retail Sales.

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Key Inputs

Docket No. E002/M-21-____
Petition
Attachment 12

Line No		2019			2020			2021			2022			2023		
1	**Capital Structure**	Cost	Ratio	WACC	Cost	Ratio	WACC	Cost	Ratio	WACC	Cost	Ratio	WACC	Cost	Ratio	WACC
2	Long Term Debt	4.75%	45.81%	2.18%	4.75%	45.81%	2.18%	4.75%	45.81%	2.18%	4.75%	45.81%	2.18%	4.75%	45.81%	2.18%
3	Short Term Debt	4.31%	1.69%	0.07%	4.31%	1.69%	0.07%	4.31%	1.69%	0.07%	4.31%	1.69%	0.07%	4.31%	1.69%	0.07%
4	Preferred Stock	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
5	Common Equity	9.06%	52.50%	4.76%	9.06%	52.50%	4.76%	9.06%	52.50%	4.76%	9.06%	52.50%	4.76%	9.06%	52.50%	4.76%
6	**Required Rate of Return**			7.01%			7.01%			7.01%			7.01%			7.01%
7	*Rates and Ratios from Settlement in Docket E002/GR-15-826, ROE as discussed in TCR petition															
8																
9	**Property Tax Rate - Annual**			1.5410%			1.5062%			1.4828%			1.4828%			1.4828%
10																
11	**Income Tax Rates**															
12	Federal Tax Rate			21.00%			21.00%			21.00%			21.00%			21.00%
13	State Tax Rate			9.80%			9.80%			9.80%			9.80%			9.80%
14	State Composite Income Tax Rate			28.74%			28.74%			28.74%			28.74%			28.74%
15	Company Composite Income Tax Rate			28.11%			28.03%			28.03%			28.03%			28.03%
16																
17	**Annual OATT Credit Factor**			25.81%			24.57%			25.08%			23.91%			23.91%
18																
19	**Allocators (As Approved in Docket E002/GR-15-826)**															
20	MN 12-month CP Demand (Electric Demand)*			87.3461%			87.3461%			87.3461%			87.3461%			87.3461%
21	NSPM 36-month CP Demand (Interchange Electric)			83.8864%			83.8543%			83.6786%			83.7474%			83.6077%
22	**Jurisdictional Allocator**			**73.2715%**			**73.2435%**			**73.0900%**			**73.1501%**			**73.0281%**
23	* As Approved in Docket E002/GR-15-826															

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
OATT Credit Factor

Line No.	Description	2019 Revenue Included in OATT Credit	2019 Revenue Excluded in OATT Credit	Total 2019	2020 Revenue Included in OATT Credit	2020 Revenue Excluded in OATT Credit	Total 2020	2021 Revenue Included in OATT Credit	2021 Revenue Excluded in OATT Credit	Total 2021	2022-2023 Revenue Included in OATT Credit	2022-2023 Revenue Excluded in OATT Credit	Total 2022
1	PTP Firm - Tsmn RTO	-	7,395,051	7,395,051	-	6,041,157	6,041,157	-	6,181,333	6,181,333	-	6,063,626	6,063,626
2	PTP Non-Frim - Tsmn RT	-	419,961	419,961	-	389,834	389,834	-	1,731,213	1,731,213	-	536,140	536,140
3	Network - Tsmn RTO	24,822,950	-	24,822,950	31,194,436	-	31,194,436	30,600,784	-	30,600,784	32,553,813	-	32,553,813
5	Sch 1. - Tsmn RTO	527,832	-	527,832	729,614	-	729,614	666,304	-	666,304	666,304	-	666,304
6	Sch 2 - Reactive Supply	8,592,420	-	8,592,420	8,176,008	-	8,176,008	8,563,978	-	8,563,978	8,491,538	-	8,491,538
7	Sch 24 - Bal Auth	1,067,860	-	1,067,860	1,088,318	-	1,088,318	1,225,041	-	1,225,041	1,254,449	-	1,254,449
8	Sch 26a-MVP NSP	-	64,652,917	64,652,917	-	58,694,716	58,694,716	-	62,192,877	62,192,877	-	73,677,436	73,677,436
9	Sch 26 Trans Exp Plan	-	71,141,193	71,141,193	-	69,321,991	69,321,991	-	74,608,360	74,608,360	-	69,947,082	69,947,082
10	Joint Pricing Zone - GRE*	56,808,860	-	56,808,860	48,508,238	-	48,508,238	39,159,022	-	39,159,022	41,756,112	-	41,756,112
11	Joint Pricing Zone - GRE Zone	-	-	-	-	-	-	5,305,277	-	5,305,277	5,452,101	-	5,452,101
12	Joint Pricing Zone - SMMPA	-	-	-	-	-	-	6,983,307	-	6,983,307	7,408,398	-	7,408,398
13	Joint Pricing Zone - MRES	-	-	-	-	-	-	5,716,259	-	5,716,259	6,179,912	-	6,179,912
14	Joint Pricing Zone - Sch 2 Reactive Supply	126,983	-	126,983	126,983	-	126,983	126,983	-	126,983	126,983	-	126,983
15	Contracts-SD State Pen	-	14,088	14,088	-	14,364	14,364	-	14,652	14,652	-	14,940	14,940
16	Contracts-WPPI Meter S	-	40,320	40,320	-	40,320	40,320	-	40,320	40,320	-	40,320	40,320
17	Contracts-UND	-	65,157	65,157	-	66,459	66,459	-	67,234	67,234	-	69,258	69,258
18	Contracts-Granite Fall	-	16,807	16,807	-	17,143	17,143	-	17,486	17,486	-	17,836	17,836
19	Contracts-E Grand Fork	-	52,752	52,752	-	53,807	53,807	-	54,883	54,883	-	55,981	55,981
20	Contracts-Sioux Falls	-	182,218	182,218	-	186,817	186,817	-	188,384	188,384	-	191,563	191,563
21	Self-Funding Network Upgrades	-	-	-	-	201,376	201,376	-	1,409,819	1,409,819	-	5,213,632	5,213,632
21	Marshall TOP Agreement	-	-	-	-	-	-	-	143,924	143,924	-	147,522	147,522
21	MMPA TOP Agreement	-	-	-	-	-	-	-	12,252	12,252	-	21,529	21,529
21	TOIF (Schedule 50)	-	-	-	-	-	-	-	622,438	622,438	-	622,438	622,438
22	Other (Kasota,Shakopee, St James)	-	-	-	-	-	0	-	-	-	46,888	-	46,888
23	**Total NSP Revenue**	**91,946,905**	**143,980,464**	**235,927,369**	**89,823,597**	**135,027,983**	**224,851,580**	**98,346,955**	**147,285,174**	**245,632,129**	**103,936,498**	**156,619,301**	**260,555,799**

*2019-2020 Att 0 did not separate out components of Joint Pricing Zone - Network

	2019	2020	2021	2022
Att O - Transmission charges for all transactions in divisor Line 36, Pg. 5	**91,946,905**	**89,823,597**	**98,346,955**	**103,936,498**
Att O - GROSS RR to be collected under Att) - Line 1, Pg. 1	**356,297,627**	**365,517,366**	**392,122,107**	**434,621,098**
OATT Credit Factor = Line 36 / Line 1	**25.8062%**	**24.5744%**	**25.0807%**	**23.9143%**

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Regional Expansion Criteria and Benefits (RECB)

Line No:		Jan - 2019 Actual	Feb - 2019 Actual	Mar - 2019 Actual	Apr - 2019 Actual	May - 2019 Actual	Jun - 2019 Actual	Jul - 2019 Actual	Aug - 2019 Actual	Sep - 2019 Actual	Oct - 2019 Actual	Nov - 2019 Actual	Dec - 2019 Actual	2019 Actual
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	5,698,504	4,906,016	5,421,233	4,591,660	5,008,429	5,909,885	6,988,361	6,558,217	5,828,231	5,398,125	5,067,931	5,336,017	66,712,610
3	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recovery	133,655	133,655	133,655	133,655	133,655	133,164	133,164	133,164	133,183	133,225	133,225	133,225	1,600,624
5	Schedule 26(a)	7,060,681	5,976,809	6,200,839	5,686,399	6,263,776	6,663,610	7,138,756	7,100,624	6,157,706	5,804,531	5,822,383	6,549,457	76,425,571
6	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total Revenue**	12,892,840	11,016,480	11,755,727	10,411,714	11,405,860	12,706,659	14,260,281	13,792,005	12,119,120	11,335,881	11,023,539	12,018,699	144,738,805
8														
9	**Expense**													
10	Schedule 26	5,903,561	5,256,383	5,603,719	4,822,119	5,664,449	6,333,309	7,599,450	7,358,212	6,607,752	4,814,424	5,296,008	5,657,620	70,917,005
11	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Schedule 26(a)	5,674,109	4,986,415	4,996,380	4,778,197	5,021,064	5,549,991	5,878,324	5,852,215	5,005,748	4,714,273	4,627,797	5,475,969	62,560,481
13	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sch 26(a) - RT MVP DIST	(116,444)	(58,738)	(25,992)	(23,992)	(25,169)	(8,793)	(9,070)	(7,308)	(1,824)	(1,781)	(1,895)	(54,964)	(335,971)
15	**Total Expense**	11,461,226	10,184,060	10,574,107	9,576,323	10,660,344	11,874,507	13,468,705	13,203,119	11,611,676	9,526,915	9,921,909	11,078,624	133,141,515
16														
17	**Net Revenue/Expense**	(1,431,614)	(832,420)	(1,181,620)	(835,391)	(745,516)	(832,152)	(791,576)	(588,886)	(507,444)	(1,808,966)	(1,101,629)	(940,075)	(11,597,290)
18	Demand Allocator - State of MN Jur	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%	73.27%
19	**Net RECB Revenue Requirements**	**(1,048,965)**	**(609,927)**	**(865,791)**	**(612,103)**	**(546,251)**	**(609,730)**	**(580,000)**	**(431,486)**	**(371,812)**	**(1,325,456)**	**(807,180)**	**(688,807)**	**(8,497,508)**

Line No:		Jan - 2020 Actual	Feb - 2020 Actual	Mar - 2020 Actual	Apr - 2020 Actual	May - 2020 Actual	Jun - 2020 Actual	Jul - 2020 Actual	Aug - 2020 Actual	Sep - 2020 Actual	Oct - 2020 Actual	Nov - 2020 Actual	Dec - 2020 Actual	2020 Actual
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	4,603,237	3,957,680	4,112,358	1,620,207	4,676,029	5,371,963	6,125,893	5,232,116	4,897,596	4,086,318	4,120,516	4,507,502	53,311,415
3	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recovery	117,103	113,589	117,101	68,949	117,101	117,104	116,299	98,794	120,337	116,317	116,317	116,317	1,335,327
5	Schedule 26(a)	6,283,428	5,595,137	5,726,287	4,999,049	5,187,547	5,512,746	4,824,063	5,325,976	5,832,262	5,395,455	5,592,901	5,847,191	66,122,041
6	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total Revenue**	11,003,769	9,666,405	9,955,745	6,688,205	9,980,677	11,001,813	11,066,255	10,656,886	10,850,194	9,598,090	9,829,734	10,471,010	120,768,783
8														
9	**Expense**													
10	Schedule 26	4,769,194	4,096,496	4,202,088	2,225,049	4,639,686	5,915,930	6,745,276	5,752,031	4,939,109	4,182,809	4,260,468	4,563,515	56,291,650
11	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Schedule 26(a)	6,194,047	5,222,596	5,422,846	4,941,012	5,098,049	5,406,505	6,086,464	5,317,541	5,398,930	5,321,467	5,430,982	5,524,648	65,365,087
13	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sch 26(a) - RT MVP DIST	(53,020)	(55,839)	(6,509)	(8,104)	(8,344)	(3,733)	(3,696)	(3,702)	(4,261)	(3,936)	(4,276)	(35,440)	(190,859)
15	**Total Expense**	10,910,222	9,263,254	9,618,425	7,157,958	9,729,391	11,318,701	12,828,044	11,065,869	10,333,778	9,500,340	9,687,173	10,052,724	121,465,877
16														
17	**Net Revenue/Expense**	(93,548)	(403,151)	(337,320)	469,752	(251,286)	316,888	1,761,789	408,984	(516,416)	(97,750)	(142,561)	(418,286)	697,095
18	Demand Allocator - State of MN Jur	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%
19	**Net RECB Revenue Requirements**	**(68,518)**	**(295,282)**	**(247,065)**	**344,063**	**(184,050)**	**232,100**	**1,290,395**	**299,554**	**(378,241)**	**(71,596)**	**(104,417)**	**(306,367)**	**510,576**

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
Regional Expansion Criteria and Benefits (RECB)

Line No:		Jan - 2021 Actual	Feb - 2021 Actual	Mar - 2021 Actual	Apr - 2021 Actual	May - 2021 Actual	Jun - 2021 Actual	Jul - 2021 Forecast	Aug - 2021 Forecast	Sep - 2021 Forecast	Oct - 2021 Forecast	Nov - 2021 Forecast	Dec - 2021 Forecast	2021 Forecast
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	5,972,057	4,364,568	3,606,957	5,248,824	5,251,540	5,902,168	6,435,889	6,198,821	5,499,630	4,776,499	4,608,070	4,879,780	62,744,801
3	Sch 26 - NSPM FERC Audit Adjustment	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(46,115)	(553,382)
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recovery	135,701	122,722	122,722	125,298	107,836	122,749	124,056	124,056	124,056	124,056	124,056	124,056	1,481,362
5	Schedule 26(a)	7,634,901	5,773,733	5,964,980	5,208,179	5,059,226	6,632,124	8,197,975	7,600,887	6,257,490	6,411,306	6,706,205	7,022,098	78,469,103
6	Sch 26(a) - NSPM FERC Audit Adjustment	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(42,286)	(507,435)
7	**Total Revenue**	13,654,257	10,172,622	9,606,258	10,493,898	10,330,201	12,568,640	14,669,517	13,835,362	11,792,774	11,223,458	11,349,929	11,937,532	141,634,449
8														
9	**Expense**													
10	Schedule 26	5,537,318	4,851,002	4,782,241	4,488,649	5,762,858	7,484,759	7,785,520	7,289,041	6,147,398	4,748,120	4,705,074	5,332,050	68,914,030
11	Sch 26 - NSPM FERC Audit Adjustment	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	16,620	199,439
12	Schedule 26(a)	6,012,998	5,295,334	5,197,510	4,586,113	4,642,459	6,299,824	6,845,173	6,343,810	5,215,787	5,344,943	5,592,564	5,857,813	67,234,327
13	Sch 26(a) - NSPM FERC Audit Adjustment	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	2,994	35,925
14	Sch 26(a) - RT MVP DIST	(33,879)	(33,896)	(25,880)	(27,026)	(26,300)	(5,702)	(7,451)	(7,438)	(9,109)	(9,062)	(9,215)	(20,185)	(215,143)
15	**Total Expense**	11,536,051	10,132,053	9,973,485	9,067,349	10,398,631	13,798,494	14,642,855	13,645,027	11,373,690	10,103,615	10,308,036	11,189,291	136,168,578
16														
17	**Net Revenue/Expense**	(2,118,206)	(40,569)	367,227	(1,426,549)	68,431	1,229,854	(26,662)	(190,335)	(419,084)	(1,119,843)	(1,041,893)	(748,241)	(5,465,871)
18	Demand Allocator - State of MN Jur	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%
19	**Net RECB Revenue Requirements**	**(1,548,197)**	**(29,652)**	**268,406**	**(1,042,665)**	**50,016**	**898,900**	**(19,488)**	**(139,116)**	**(306,308)**	**(818,493)**	**(761,519)**	**(546,889)**	**(3,995,005)**

Line No:		Jan - 2022 Forecast	Feb - 2022 Forecast	Mar - 2022 Forecast	Apr - 2022 Forecast	May - 2022 Forecast	Jun - 2022 Forecast	Jul - 2022 Forecast	Aug - 2022 Forecast	Sep - 2022 Forecast	Oct - 2022 Forecast	Nov - 2022 Forecast	Dec - 2022 Forecast	2022 Forecast
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	6,063,206	5,302,123	5,263,880	4,732,036	5,897,985	6,593,155	7,286,851	7,017,135	6,221,651	5,398,931	5,207,307	5,516,437	70,500,696
3	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recovery	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	1,488,667
5	Schedule 26(a)	6,758,391	6,254,835	5,997,729	5,138,199	5,367,282	6,558,315	7,707,565	7,143,285	5,873,702	6,019,066	6,297,762	6,596,298	75,712,431
6	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total Revenue**	12,945,652	11,681,014	11,385,664	9,994,291	11,389,322	13,275,526	15,118,471	14,284,475	12,219,409	11,542,053	11,629,125	12,236,791	147,701,794
8														
9	**Expense**													
10	Schedule 26	5,466,845	4,711,228	5,018,275	4,482,554	5,679,968	7,177,031	8,060,509	7,537,355	6,321,901	4,876,069	4,823,577	5,459,282	69,614,593
11	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Schedule 26(a)	5,816,151	5,382,800	5,161,539	4,421,843	4,618,988	5,643,970	6,632,994	6,147,384	5,054,804	5,179,902	5,419,743	5,676,657	65,156,775
13	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sch 26(a) - RT MVP DIST	(20,045)	(20,219)	(30,503)	(31,393)	(30,854)	(7,631)	(7,451)	(7,438)	(9,109)	(9,062)	(9,215)	(20,185)	(203,105)
15	**Total Expense**	11,262,952	10,073,808	10,149,311	8,873,004	10,268,102	12,813,370	14,686,052	13,677,301	11,367,596	10,046,909	10,234,105	11,115,755	134,568,263
16														
17	**Net Revenue/Expense**	(1,682,701)	(1,607,206)	(1,236,353)	(1,121,287)	(1,121,220)	(462,157)	(432,420)	(607,174)	(851,813)	(1,495,145)	(1,395,020)	(1,121,036)	(13,133,530)
18	Demand Allocator - State of MN Jur	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.15%
19	**Net RECB Revenue Requirements**	**(1,229,886)**	**(1,174,707)**	**(903,650)**	**(819,549)**	**(819,500)**	**(337,790)**	**(316,056)**	**(443,783)**	**(622,590)**	**(1,092,801)**	**(1,019,620)**	**(819,365)**	**(9,607,189)**

Line No:		Jan - 2023 Forecast	Feb - 2023 Forecast	Mar - 2023 Forecast	Apr - 2023 Forecast	May - 2023 Forecast	Jun - 2023 Forecast	Jul - 2023 Forecast	Aug - 2023 Forecast	Sep - 2023 Forecast	Oct - 2023 Forecast	Nov - 2023 Forecast	Dec - 2023 Forecast	2023 Forecast
1	**Revenue**													
2	Schedule 26 wo Sch 37/38	5,931,452	5,186,576	5,149,147	4,628,628	5,769,749	6,450,117	7,129,040	6,865,067	6,086,523	5,281,323	5,093,779	5,396,326	68,967,728
3	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
4	Schedule 37 & 38 - Trans Expansion Plan Cost Recovery	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	124,056	1,488,667
5	Schedule 26(a)	6,661,309	6,164,987	5,911,574	5,064,391	5,290,183	6,464,108	7,596,849	7,040,674	5,789,329	5,932,605	6,207,297	6,501,545	74,624,850
6	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
7	**Total Revenue**	12,716,817	11,475,618	11,184,777	9,817,075	11,183,988	13,038,280	14,849,944	14,029,797	11,999,908	11,337,983	11,425,132	12,021,926	145,081,244
8														
9	**Expense**													
10	Schedule 26	5,355,805	4,596,597	4,916,814	4,398,597	5,549,011	7,069,069	7,970,680	7,423,725	6,183,780	4,741,974	4,681,603	5,306,940	68,194,593
11	Sch 26 - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
12	Schedule 26(a)	5,554,064	5,140,241	4,928,950	4,222,586	4,410,847	5,389,642	6,334,098	5,870,371	4,827,025	4,946,485	5,175,519	5,420,856	62,220,685
13	Sch 26(a) - NSPM FERC Audit Adjustment	-	-	-	-	-	-	-	-	-	-	-	-	-
14	Sch 26(a) - RT MVP DIST	(20,045)	(20,219)	(30,503)	(31,393)	(30,854)	(7,631)	(7,451)	(7,438)	(9,109)	(9,062)	(9,215)	(20,185)	(203,105)
15	**Total Expense**	10,889,824	9,716,619	9,815,261	8,589,789	9,929,004	12,451,080	14,297,327	13,286,658	11,001,696	9,679,397	9,847,906	10,707,611	130,212,172
16														
17	**Net Revenue/Expense**	(1,826,992)	(1,759,000)	(1,369,516)	(1,227,285)	(1,254,984)	(587,200)	(552,618)	(743,139)	(998,212)	(1,658,586)	(1,577,225)	(1,314,315)	(14,869,072)
18	Demand Allocator - State of MN Jur	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%	73.03%
19	**Net RECB Revenue Requirements**	**(1,334,217)**	**(1,284,564)**	**(1,000,131)**	**(896,263)**	**(916,490)**	**(428,821)**	**(403,566)**	**(542,700)**	**(728,975)**	**(1,211,233)**	**(1,151,817)**	**(959,819)**	**(10,858,596)**

Project	Rider Components	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
AGIS - ADMS	CWIP Balance	19,708,445	20,299,866	21,182,527	21,899,736	22,448,648	23,023,454	23,381,775	23,790,518	24,476,157	24,933,972	25,460,707	24,350,490	**24,350,490**
AGIS - ADMS	Plant In-Service												1,488,800	**1,488,800**
AGIS - ADMS	Depreciation Reserve												12,407	**12,407**
AGIS - ADMS	Accumulated Deferred Taxes	52,712	58,214	63,716	69,217	74,719	80,221	85,722	91,224	96,726	102,227	107,729	113,231	**113,231**
AGIS - ADMS	Average Rate Base	19,193,273	19,948,692	20,680,232	21,474,665	22,102,224	22,658,581	23,119,643	23,497,673	24,039,363	24,605,588	25,092,362	25,533,316	**25,533,316**
AGIS - ADMS	Tax Depreciation Expense	20,682	20,682	20,682	20,682	20,682	20,682	20,682	20,682	20,682	20,682	20,682	20,682	**248,183**
AGIS - ADMS	CPI-TAX INTEREST													
AGIS - ADMS	Debt Return	35,987	37,404	38,775	40,265	41,442	42,485	43,349	44,058	45,074	46,135	47,048	47,875	**509,898**
AGIS - ADMS	Equity Return	76,133	79,130	82,032	85,183	87,672	89,879	91,708	93,207	95,356	97,602	99,533	101,282	**1,078,718**
AGIS - ADMS	Current Income Tax Requirement	24,585	25,794	26,965	28,236	29,240	30,130	30,868	31,472	32,339	33,245	34,024	39,734	**366,631**
AGIS - ADMS	Book Depreciation												12,407	**12,407**
AGIS - ADMS	AFUDC													
AGIS - ADMS	Deferred Taxes	5,502	5,502	5,502	5,502	5,502	5,502	5,502	5,502	5,502	5,502	5,502	5,502	**66,020**
AGIS - ADMS	Operating Expenses					12,532		73,780	24,593	24,593	24,593	24,593	24,593	**209,278**
AGIS - ADMS	Property Tax Expense													
AGIS - ADMS	OATT Credit													
AGIS - ADMS	Total Revenue Requirement	142,208	147,829	153,273	159,185	176,387	167,995	245,206	198,833	202,864	207,078	210,700	231,392	**2,242,951**
AGIS - ADMS	**Rider Revenue Requirement**	123,802	128,696	133,436	138,584	155,182	146,256	223,022	176,285	179,794	183,462	186,616	204,641	**1,979,777**
AGIS - AMI	CWIP Balance	1,473,448	1,476,434	1,482,152	1,482,572	1,486,497	1,491,964	1,493,998	6,420	6,375	68,734	69,065	249,904	**249,904**
AGIS - AMI	Plant In-Service								1,492,337	1,494,952	1,502,070	1,500,894	1,500,894	**1,500,894**
AGIS - AMI	Depreciation Reserve								9,485	28,473	47,522	66,609	85,689	**85,689**
AGIS - AMI	Accumulated Deferred Taxes	5,015	10,031	15,046	20,061	25,076	30,092	35,107	40,122	45,138	50,153	55,168	60,184	**60,184**
AGIS - AMI	Average Rate Base	1,457,848	1,467,418	1,466,755	1,464,808	1,461,966	1,461,646	1,460,382	1,454,020	1,438,433	1,450,423	1,460,655	1,526,553	**1,526,553**
AGIS - AMI	Tax Depreciation Expense	25,015	25,015	25,015	25,015	25,015	25,015	25,015	25,015	25,015	25,015	25,015	25,015	**300,179**
AGIS - AMI	CPI-TAX INTEREST													
AGIS - AMI	Debt Return	2,733	2,751	2,750	2,747	2,741	2,741	2,738	2,726	2,697	2,720	2,739	2,862	**32,945**
AGIS - AMI	Equity Return	5,783	5,821	5,818	5,810	5,799	5,798	5,793	5,768	5,706	5,753	5,794	6,055	**69,698**
AGIS - AMI	Current Income Tax Requirement	(5,734)	(5,719)	(5,720)	(5,723)	(5,728)	(5,728)	(5,730)	(1,915)	1,893	1,937	1,969	2,071	**(34,127)**
AGIS - AMI	Book Depreciation								9,485	18,987	19,049	19,087	19,080	**85,689**
AGIS - AMI	AFUDC										169	338	825	**1,332**
AGIS - AMI	Deferred Taxes	5,015	5,015	5,015	5,015	5,015	5,015	5,015	5,015	5,015	5,015	5,015	5,015	**60,184**
AGIS - AMI	Operating Expenses													
AGIS - AMI	Property Tax Expense													
AGIS - AMI	OATT Credit													
AGIS - AMI	Total Revenue Requirement	7,797	7,868	7,863	7,849	7,828	7,825	7,816	21,080	34,299	34,643	34,942	35,909	**215,721**
AGIS - AMI	**Rider Revenue Requirement**													
AGIS - FAN	CWIP Balance	320,545	371,075	528,319	690,570	1,012,445	523,100	814,042	923,339	1,118,170	1,122,829	1,132,814	1,208,981	**1,208,981**
AGIS - FAN	Plant In-Service						496,329	513,719	521,224	525,777	531,966	527,710	529,266	**529,266**
AGIS - FAN	Depreciation Reserve						2,461	7,469	12,601	17,793	23,038	28,292	33,533	**33,533**
AGIS - FAN	Accumulated Deferred Taxes	(17)	556	1,130	1,703	2,277	2,851	3,424	3,998	4,571	5,145	5,719	6,292	**6,292**
AGIS - FAN	Average Rate Base	273,002	345,540	448,854	608,028	849,518	1,012,143	1,165,492	1,372,415	1,524,773	1,624,097	1,626,562	1,662,467	**1,662,467**
AGIS - FAN	Tax Depreciation Expense	6,259	6,259	6,259	6,259	6,259	6,259	6,259	6,259	6,259	6,259	6,259	6,259	**75,103**
AGIS - FAN	CPI-TAX INTEREST	1,277	1,481	1,869	2,526	3,544	3,474	2,991	3,549	4,028	4,437	4,504	4,554	**38,233**
AGIS - FAN	Debt Return	512	648	842	1,140	1,593	1,898	2,185	2,573	2,859	3,045	3,050	3,117	**23,462**
AGIS - FAN	Equity Return	1,083	1,371	1,780	2,412	3,370	4,015	4,623	5,444	6,048	6,442	6,452	6,594	**49,634**
AGIS - FAN	Current Income Tax Requirement	(1,341)	(1,143)	(821)	(301)	496	1,720	2,798	3,404	3,865	4,211	4,245	4,317	**21,450**
AGIS - FAN	Book Depreciation						2,461	5,008	5,132	5,192	5,245	5,254	5,241	**33,533**
AGIS - FAN	AFUDC	2,190	2,673	2,902	3,872	5,364	4,825	4,757	5,763	7,450	7,292	7,340	7,379	**61,807**
AGIS - FAN	Deferred Taxes	574	574	574	574	574	574	574	574	574	574	574	574	**6,883**
AGIS - FAN	Operating Expenses													
AGIS - FAN	Property Tax Expense													
AGIS - FAN	OATT Credit													
AGIS - FAN	Total Revenue Requirement	3,017	4,122	5,276	7,696	11,396	15,493	19,945	22,890	25,988	26,809	26,915	27,223	**196,770**
AGIS - FAN	**Rider Revenue Requirement**													

Project	Rider Components	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
AGIS - ADMS	CWIP Balance	24,804,524	25,305,992	25,861,264	26,263,652	26,631,385	27,097,765	27,613,445	28,052,568	28,470,747	29,058,855	29,432,711	30,398,879	**30,398,879**
AGIS - ADMS	Plant In-Service	1,492,867	1,496,189	1,500,919	1,501,847	1,502,156	1,502,416	1,502,725	1,502,883	1,503,040	1,505,182	1,516,725	1,525,212	**1,525,212**
AGIS - ADMS	Depreciation Reserve	38,530	64,719	90,978	117,287	143,606	169,930	196,260	222,593	248,930	275,286	301,762	328,414	**328,414**
AGIS - ADMS	Accumulated Deferred Taxes	117,582	121,934	124,039	128,461	132,742	137,164	141,445	145,797	150,218	154,500	158,921	163,203	**163,203**
AGIS - ADMS	Average Rate Base	25,927,466	26,376,228	26,880,295	27,331,248	27,686,331	28,072,929	28,533,635	28,980,588	29,378,640	29,852,305	30,309,291	30,958,473	**30,958,473**
AGIS - ADMS	Tax Depreciation Expense	41,857	41,857	41,857	41,857	41,857	41,857	41,857	41,857	41,857	41,857	41,857	41,857	**502,287**
AGIS - ADMS	CPI-TAX INTEREST													
AGIS - ADMS	Debt Return	48,614	49,455	50,401	51,246	51,912	52,637	53,501	54,339	55,085	55,973	56,830	58,047	**638,039**
AGIS - ADMS	Equity Return	102,846	104,626	106,625	108,414	109,822	111,356	113,183	114,956	116,535	118,414	120,227	122,802	**1,349,807**
AGIS - ADMS	Current Income Tax Requirement	36,892	37,636	38,471	39,213	39,785	40,406	41,145	41,861	42,499	43,265	44,045	45,154	**490,372**
AGIS - ADMS	Book Depreciation	26,124	26,188	26,259	26,309	26,319	26,324	26,329	26,334	26,336	26,356	26,476	26,652	**316,007**
AGIS - ADMS	AFUDC													
AGIS - ADMS	Deferred Taxes	4,351	4,351	4,351	4,351	4,351	4,351	4,351	4,351	4,351	4,351	4,351	4,351	**52,218**
AGIS - ADMS	Operating Expenses	8,816	23,644	21,043	32,696	5,706	15,459	28,515	34,537	59,240	37,048	40,428	12,784	**319,917**
AGIS - ADMS	Property Tax Expense													
AGIS - ADMS	OATT Credit													
AGIS - ADMS	Total Revenue Requirement	227,643	245,901	247,150	262,229	237,897	250,533	267,024	276,378	304,047	285,409	292,358	269,790	**3,166,360**
AGIS - ADMS	**Rider Revenue Requirement**	199,410	217,224	217,974	232,610	207,934	220,197	236,244	245,169	272,455	253,358	259,847	236,624	**2,799,047**
AGIS - AMI	CWIP Balance	346,591	415,827	575,125	821,754	1,018,976	1,347,674	1,690,307	1,898,332	2,201,016	2,510,249	3,026,854	4,455,317	**4,455,317**
AGIS - AMI	Plant In-Service	1,501,018	1,501,018	1,501,018	1,501,018	1,501,018	1,501,018	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	**1,507,438**
AGIS - AMI	Depreciation Reserve	104,769	123,850	142,932	162,013	181,094	200,175	219,274	238,389	257,505	276,621	295,736	314,852	**314,852**
AGIS - AMI	Accumulated Deferred Taxes	66,034	71,884	74,714	80,659	86,415	92,359	98,115	103,965	109,909	115,665	121,609	127,365	**127,365**
AGIS - AMI	Average Rate Base	1,640,865	1,696,033	1,788,388	1,966,326	2,163,415	2,401,349	2,715,379	2,968,961	3,199,255	3,480,342	3,868,201	4,815,864	**4,815,864**
AGIS - AMI	Tax Depreciation Expense	40,102	40,102	40,102	40,102	40,102	40,102	40,102	40,102	40,102	40,102	40,102	40,102	**481,228**
AGIS - AMI	CPI-TAX INTEREST									86	146	456	946	**1,634**
AGIS - AMI	Debt Return	3,077	3,180	3,353	3,687	4,056	4,503	5,091	5,567	5,999	6,526	7,253	9,030	**61,321**
AGIS - AMI	Equity Return	6,509	6,728	7,094	7,800	8,582	9,525	10,771	11,777	12,690	13,805	15,344	19,103	**129,727**
AGIS - AMI	Current Income Tax Requirement	(3,494)	(3,406)	(3,258)	(2,973)	(2,658)	(2,277)	(1,768)	(1,355)	(952)	(478)	268	1,981	**(20,370)**
AGIS - AMI	Book Depreciation	19,080	19,081	19,081	19,081	19,081	19,081	19,098	19,116	19,116	19,116	19,116	19,116	**229,163**
AGIS - AMI	AFUDC													
AGIS - AMI	Deferred Taxes	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	5,850	**70,201**
AGIS - AMI	Operating Expenses	11,241	45,552	59,863	111,536	41,616	72,165	29,912	39,391	64,333	52,968	156,172	115,500	**800,249**
AGIS - AMI	Property Tax Expense													
AGIS - AMI	OATT Credit													
AGIS - AMI	Total Revenue Requirement	42,262	76,986	91,984	144,981	76,527	108,847	68,955	80,345	107,036	97,787	204,002	170,579	**1,270,290**
AGIS - AMI	**Rider Revenue Requirement**	38,246	72,917	87,828	140,658	72,019	104,114	63,923	75,072	101,547	92,035	197,950	163,730	**1,210,039**
AGIS - FAN	CWIP Balance	1,208,981	1,227,399	1,228,742	1,228,742	308,819	308,689	310,972	309,618	341,078	685,506	1,279,293	1,581,338	**1,581,338**
AGIS - FAN	Plant In-Service	529,266	529,266	529,755	529,755	1,449,805	1,449,935	1,449,935	1,450,023	1,450,023	1,450,023	1,450,023	1,474,811	**1,474,811**
AGIS - FAN	Depreciation Reserve	35,157	36,780	38,405	40,030	43,066	47,513	51,961	56,409	60,857	65,305	69,752	74,238	**74,238**
AGIS - FAN	Accumulated Deferred Taxes	10,652	15,011	17,120	21,550	25,839	30,269	34,558	38,917	43,347	47,636	52,066	56,355	**56,355**
AGIS - FAN	Average Rate Base	1,695,430	1,696,476	1,702,868	1,697,729	1,691,173	1,683,066	1,675,470	1,667,172	1,673,391	1,852,598	2,312,828	2,764,382	**2,764,382**
AGIS - FAN	Tax Depreciation Expense	21,666	21,666	21,666	21,666	21,666	21,666	21,666	21,666	21,666	21,666	21,666	21,666	**259,998**
AGIS - FAN	CPI-TAX INTEREST	4,585	4,520	4,938	4,997	2,827	479	398	536	721	1,429	3,187	5,073	**33,691**
AGIS - FAN	Debt Return	3,179	3,181	3,193	3,183	3,171	3,156	3,142	3,126	3,138	3,474	4,337	5,183	**41,461**
AGIS - FAN	Equity Return	6,725	6,729	6,755	6,734	6,708	6,676	6,646	6,613	6,638	7,349	9,174	10,965	**87,713**
AGIS - FAN	Current Income Tax Requirement	(1,764)	(1,789)	(1,609)	(1,593)	(1,910)	(2,301)	(2,346)	(2,303)	(2,219)	(1,646)	(201)	1,298	**(18,383)**
AGIS - FAN	Book Depreciation	1,624	1,624	1,624	1,625	3,036	4,447	4,448	4,448	4,448	4,448	4,448	4,486	**40,705**
AGIS - FAN	AFUDC													
AGIS - FAN	Deferred Taxes	4,359	4,359	4,359	4,359	4,359	4,359	4,359	4,359	4,359	4,359	4,359	4,359	**52,313**
AGIS - FAN	Operating Expenses	1,534	4,613	12,066	5,969	715	2,634	5,080	5,895	10,446	6,345	6,949	9,315	**71,560**
AGIS - FAN	Property Tax Expense													
AGIS - FAN	OATT Credit													
AGIS - FAN	Total Revenue Requirement	15,657	18,718	26,388	20,277	16,080	18,972	21,329	22,138	26,810	24,328	29,067	35,607	**275,369**
AGIS - FAN	**Rider Revenue Requirement**	12,773	15,838	23,464	17,356	12,944	15,638	18,013	18,824	23,482	20,791	24,977	30,880	**234,981**

Project	Rider Components	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
AGIS - ADMS	CWIP Balance	30,643,761	30,837,841	31,142,783	1,046,917	1,330,505	1,597,513	2,056,569	2,500,966	2,960,090	3,406,561	3,817,496	4,090,704	**4,090,704**
AGIS - ADMS	Plant In-Service	1,527,643	1,606,156	1,606,230	31,959,991	31,975,194	31,982,612	31,982,612	31,982,612	31,982,612	31,982,612	31,982,612	31,982,612	**31,982,612**
AGIS - ADMS	Depreciation Reserve	353,568	378,968	404,596	558,696	841,392	1,124,275	1,407,218	1,690,162	1,973,106	2,256,049	2,538,993	2,821,937	**2,821,937**
AGIS - ADMS	Accumulated Deferred Taxes	192,861	247,685	302,510	357,334	412,159	466,983	521,808	576,632	631,457	686,281	741,106	795,930	**795,930**
AGIS - ADMS	Average Rate Base	31,513,896	31,693,747	31,902,213	32,038,980	32,044,100	31,993,095	32,022,099	32,136,058	32,250,050	32,365,080	32,456,014	32,460,318	**32,460,318**
AGIS - ADMS	Tax Depreciation Expense	405,881	405,881	405,881	405,881	405,881	405,881	405,881	405,881	405,881	405,881	405,881	405,881	**4,870,572**
AGIS - ADMS	CPI-TAX INTEREST				30,111									**30,111**
AGIS - ADMS	Debt Return	59,089	59,426	59,817	60,073	60,083	59,987	60,041	60,255	60,469	60,685	60,855	60,863	**721,642**
AGIS - ADMS	Equity Return	125,005	125,719	126,545	127,088	127,108	126,906	127,021	127,473	127,925	128,381	128,742	128,759	**1,526,673**
AGIS - ADMS	Current Income Tax Requirement	(81,032)	(80,645)	(80,220)	(16,036)	23,696	23,690	23,761	23,943	24,125	24,309	24,455	24,462	**(65,493)**
AGIS - ADMS	Book Depreciation	25,153	25,401	25,628	154,100	282,696	282,882	282,944	282,944	282,944	282,944	282,944	282,944	**2,493,522**
AGIS - ADMS	AFUDC													
AGIS - ADMS	Deferred Taxes	54,824	54,824	54,824	54,824	54,824	54,824	54,824	54,824	54,824	54,824	54,824	54,824	**657,894**
AGIS - ADMS	Operating Expenses	(1,984)	12,413	10,976	11,377	23,805	3,481	76,743	74,830	76,743	78,906	80,010	89,082	**536,382**
AGIS - ADMS	Property Tax Expense													
AGIS - ADMS	OATT Credit													
AGIS - ADMS	Total Revenue Requirement	181,056	197,138	197,572	391,425	572,213	551,771	625,334	624,269	627,030	630,050	631,830	640,934	**5,870,621**
AGIS - ADMS	**Rider Revenue Requirement**	157,549	173,414	173,608	342,611	501,771	481,345	554,869	553,695	556,348	559,257	560,950	570,051	**5,185,468**
AGIS - AMI	CWIP Balance	4,818,334	5,125,647	5,661,567	5,957,683	6,584,292	7,225,547	7,462,307	7,694,770	7,925,154	8,523,147	10,871,913	14,159,029	**14,159,029**
AGIS - AMI	Plant In-Service	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	1,507,438	1,517,756	**1,517,756**
AGIS - AMI	Depreciation Reserve	335,596	356,341	377,085	397,829	418,574	439,318	460,063	480,807	501,551	522,296	543,040	563,856	**563,856**
AGIS - AMI	Accumulated Deferred Taxes	130,774	131,553	132,332	133,110	133,889	134,668	135,447	136,226	137,005	137,783	138,562	139,341	**139,341**
AGIS - AMI	Average Rate Base	5,688,265	6,001,907	6,402,000	6,796,495	7,236,334	7,848,743	8,266,227	8,479,315	8,689,215	9,081,881	10,533,737	13,335,279	**13,335,279**
AGIS - AMI	Tax Depreciation Expense	24,321	24,321	24,321	24,321	24,321	24,321	24,321	24,321	24,321	24,321	24,321	24,321	**291,847**
AGIS - AMI	CPI-TAX INTEREST	1,145	674	987	1,291	1,618	1,871	1,916						**9,502**
AGIS - AMI	Debt Return	10,665	11,254	12,004	12,743	13,568	14,716	15,499	15,899	16,292	17,029	19,751	25,004	**184,424**
AGIS - AMI	Equity Return	22,563	23,808	25,395	26,959	28,704	31,133	32,789	33,635	34,467	36,025	41,784	52,897	**390,159**
AGIS - AMI	Current Income Tax Requirement	8,435	8,746	9,513	10,267	11,102	12,184	12,870	12,438	12,774	13,402	15,725	20,236	**147,693**
AGIS - AMI	Book Depreciation	20,744	20,744	20,744	20,744	20,744	20,744	20,744	20,744	20,744	20,744	20,744	20,816	**249,004**
AGIS - AMI	AFUDC													
AGIS - AMI	Deferred Taxes	779	779	779	779	779	779	779	779	779	779	779	779	**9,346**
AGIS - AMI	Operating Expenses	91,266	145,051	85,417	134,840	70,831	76,261	472,794	469,318	481,568	618,087	545,328	582,830	**3,773,590**
AGIS - AMI	Property Tax Expense													
AGIS - AMI	OATT Credit													
AGIS - AMI	Total Revenue Requirement	154,453	210,381	153,852	206,333	145,728	155,818	555,476	552,813	566,624	706,066	644,111	702,561	**4,754,216**
AGIS - AMI	**Rider Revenue Requirement**	146,580	202,187	145,274	197,413	136,428	145,970	545,305	542,563	556,299	695,668	633,644	692,012	**4,639,342**
AGIS - FAN	CWIP Balance	1,849,421	1,922,750	2,116,170	2,671,881	3,573,809	135,335	(10,672)	(1,585)	4,322	8,162	10,657	54,222	**54,222**
AGIS - FAN	Plant In-Service	1,474,811	1,474,811	1,475,073	1,475,073	1,475,073	5,969,781	6,663,825	6,849,409	7,224,763	7,613,099	8,242,582	8,417,573	**8,417,573**
AGIS - FAN	Depreciation Reserve	80,149	86,060	91,971	97,883	103,795	127,005	170,260	217,041	266,181	318,533	375,165	435,179	**435,179**
AGIS - FAN	Accumulated Deferred Taxes	69,446	91,128	112,810	134,492	156,175	177,857	199,539	221,221	242,903	264,585	286,267	307,949	**307,949**
AGIS - FAN	Average Rate Base	3,043,551	3,186,664	3,292,576	3,639,679	4,340,904	5,283,742	6,030,963	6,335,617	6,553,940	6,868,230	7,304,134	7,649,395	**7,649,395**
AGIS - FAN	Tax Depreciation Expense	109,586	109,586	109,586	109,586	109,586	109,586	109,586	109,586	109,586	109,586	109,586	109,586	**1,315,027**
AGIS - FAN	CPI-TAX INTEREST	6,278	4,155	6,295	8,138	4,170								**29,036**
AGIS - FAN	Debt Return	5,707	5,975	6,174	6,824	8,139	9,907	11,308	11,879	12,289	12,878	13,695	14,343	**119,118**
AGIS - FAN	Equity Return	12,073	12,640	13,061	14,437	17,219	20,959	23,923	25,131	25,997	27,244	28,973	30,343	**252,000**
AGIS - FAN	Current Income Tax Requirement	(25,670)	(26,297)	(25,265)	(23,966)	(24,444)	(17,640)	(8,360)	(6,450)	(5,149)	(3,351)	(927)	990	**(166,530)**
AGIS - FAN	Book Depreciation	5,911	5,911	5,911	5,912	5,912	23,210	43,255	46,781	49,140	52,352	56,632	60,014	**360,941**
AGIS - FAN	AFUDC													
AGIS - FAN	Deferred Taxes	21,682	21,682	21,682	21,682	21,682	21,682	21,682	21,682	21,682	21,682	21,682	21,682	**260,186**
AGIS - FAN	Operating Expenses	(3,575)	10,666	9,255	9,644	21,890	6,205	76,408	74,523	76,408	80,798	81,885	90,824	**534,930**
AGIS - FAN	Property Tax Expense													
AGIS - FAN	OATT Credit													
AGIS - FAN	Total Revenue Requirement	16,128	30,577	30,818	34,534	50,398	64,323	168,215	173,547	180,367	191,603	201,940	218,195	**1,360,644**
AGIS - FAN	**Rider Revenue Requirement**	12,454	26,868	26,883	30,161	45,616	55,629	155,074	159,473	165,666	176,030	185,186	200,509	**1,239,549**

Project	Rider Components	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
AGIS - ADMS	CWIP Balance	4,347,261	4,507,499	1,694,074	1,813,309	1,932,544	2,051,778	2,171,013	2,249,133	2,327,252	2,448,132	2,560,788	2,673,444	**2,673,444**
AGIS - ADMS	Plant In-Service	31,982,612	31,982,612	34,966,018	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	**35,023,823**
AGIS - ADMS	Depreciation Reserve	3,104,880	3,387,824	3,683,313	3,991,590	4,300,111	4,608,632	4,917,152	5,225,673	5,534,194	5,842,715	6,151,235	6,459,756	**6,459,756**
AGIS - ADMS	Accumulated Deferred Taxes	876,039	981,431	1,086,823	1,192,215	1,297,608	1,403,000	1,506,692	1,612,085	1,719,177	1,822,869	1,929,961	2,033,654	**2,033,654**
AGIS - ADMS	Average Rate Base	32,362,148	32,182,210	31,952,710	31,718,945	31,453,291	31,158,613	30,865,635	30,550,399	30,212,905	29,900,192	29,601,347	29,301,790	**29,301,790**
AGIS - ADMS	Tax Depreciation Expense	677,410	677,410	677,410	677,410	677,410	677,410	677,410	677,410	677,410	677,410	677,410	677,410	**8,128,915**
AGIS - ADMS	CPI-TAX INTEREST													
AGIS - ADMS	Debt Return	60,679	60,342	59,911	59,473	58,975	58,422	57,873	57,282	56,649	56,063	55,503	54,941	**696,113**
AGIS - ADMS	Equity Return	128,370	127,656	126,746	125,818	124,765	123,596	122,434	121,183	119,845	118,604	117,419	116,230	**1,472,665**
AGIS - ADMS	Current Income Tax Requirement	(64,820)	(65,108)	(60,415)	(55,631)	(55,958)	(56,429)	(56,898)	(57,402)	(57,942)	(58,443)	(58,921)	(59,400)	**(707,366)**
AGIS - ADMS	Book Depreciation	282,944	282,944	295,489	308,278	308,521	308,521	308,521	308,521	308,521	308,521	308,521	308,521	**3,637,819**
AGIS - ADMS	AFUDC													
AGIS - ADMS	Deferred Taxes	105,392	105,392	105,392	105,392	105,392	105,392	105,392	105,392	105,392	105,392	105,392	105,392	**1,264,707**
AGIS - ADMS	Operating Expenses	29,060	29,060	29,060	29,060	29,060	29,060	29,060	29,060	29,060	29,060	29,060	29,060	**348,721**
AGIS - ADMS	Property Tax Expense													
AGIS - ADMS	OATT Credit													
AGIS - ADMS	Total Revenue Requirement	541,625	540,286	556,184	572,391	570,755	568,562	566,382	564,036	561,525	559,197	556,974	554,744	**6,712,660**
AGIS - ADMS	**Rider Revenue Requirement**	475,788	474,621	488,477	502,602	501,177	499,266	497,366	495,321	493,132	491,104	489,166	487,224	**5,895,245**
AGIS - AMI	CWIP Balance	5,886,663	8,364,105	6,466,263	6,466,263	6,466,263	6,466,263	6,466,263	6,466,263	6,466,263	6,466,263	6,466,263	6,466,263	**6,466,263**
AGIS - AMI	Plant In-Service	14,773,393	19,922,554	27,900,866	33,644,976	39,149,846	45,987,059	51,731,169	57,236,039	62,740,909	68,485,019	74,859,500	81,233,981	**81,233,981**
AGIS - AMI	Depreciation Reserve	619,946	721,967	856,490	1,024,754	1,216,454	1,440,281	1,696,736	1,976,625	2,279,452	2,605,713	2,957,222	3,335,291	**3,335,291**
AGIS - AMI	Accumulated Deferred Taxes	153,600	181,338	209,076	236,814	264,552	292,290	319,581	347,319	375,504	402,795	430,981	458,271	**458,271**
AGIS - AMI	Average Rate Base	17,422,920	23,621,063	30,328,590	36,061,748	41,478,518	47,414,058	53,437,288	58,765,868	63,951,194	69,233,849	74,926,074	80,908,475	**80,908,475**
AGIS - AMI	Tax Depreciation Expense	329,903	329,903	329,903	329,903	329,903	329,903	329,903	329,903	329,903	329,903	329,903	329,903	**3,958,839**
AGIS - AMI	CPI-TAX INTEREST													
AGIS - AMI	Debt Return	32,668	44,289	56,866	67,616	77,772	88,901	100,195	110,186	119,908	129,813	140,486	151,703	**1,120,406**
AGIS - AMI	Equity Return	69,111	93,697	120,303	143,045	164,531	188,076	211,968	233,105	253,673	274,628	297,207	320,937	**2,370,280**
AGIS - AMI	Current Income Tax Requirement	(71,379)	(42,936)	(19,094)	3,688	21,808	44,263	67,060	85,038	102,586	120,491	139,782	160,066	**611,373**
AGIS - AMI	Book Depreciation	56,090	102,021	134,523	168,264	191,700	223,828	256,454	279,889	302,826	326,262	351,509	378,069	**2,771,436**
AGIS - AMI	AFUDC													
AGIS - AMI	Deferred Taxes	27,738	27,738	27,738	27,738	27,738	27,738	27,738	27,738	27,738	27,738	27,738	27,738	**332,857**
AGIS - AMI	Operating Expenses	727,937	727,937	727,937	727,937	727,937	727,937	727,937	727,937	727,937	727,937	727,937	727,937	**8,735,247**
AGIS - AMI	Property Tax Expense													
AGIS - AMI	OATT Credit													
AGIS - AMI	Total Revenue Requirement	842,166	952,747	1,048,274	1,138,289	1,211,486	1,300,743	1,391,352	1,463,894	1,534,669	1,606,869	1,684,659	1,766,451	**15,941,599**
AGIS - AMI	**Rider Revenue Requirement**	832,104	939,582	1,031,849	1,119,797	1,193,063	1,280,099	1,368,496	1,441,123	1,511,985	1,584,271	1,662,147	1,744,025	**15,708,542**
AGIS - FAN	CWIP Balance	528,085	890,796	1,253,727	1,573,816	2,312,277	2,764,000	3,093,194	3,670,788	4,445,069	5,240,172	6,230,337	6,789,358	**6,789,358**
AGIS - FAN	Plant In-Service	8,499,079	8,605,957	8,729,328	8,863,419	9,004,477	9,172,650	9,308,651	9,423,741	9,531,411	9,634,259	9,730,885	9,814,209	**9,814,209**
AGIS - FAN	Depreciation Reserve	496,272	558,157	621,011	684,947	750,040	816,433	884,106	952,834	1,022,499	1,093,050	1,164,439	1,236,585	**1,236,585**
AGIS - FAN	Accumulated Deferred Taxes	334,425	365,695	396,965	428,234	459,504	490,773	521,539	552,808	584,582	615,347	647,121	677,887	**677,887**
AGIS - FAN	Average Rate Base	7,949,328	8,369,049	8,753,355	9,128,931	9,699,997	10,352,692	10,797,439	11,276,909	11,963,256	12,752,334	13,641,961	14,403,996	**14,403,996**
AGIS - FAN	Tax Depreciation Expense	178,038	178,038	178,038	178,038	178,038	178,038	178,038	178,038	178,038	178,038	178,038	178,038	**2,136,453**
AGIS - FAN	CPI-TAX INTEREST													
AGIS - FAN	Debt Return	14,905	15,692	16,413	17,117	18,187	19,411	20,245	21,144	22,431	23,911	25,579	27,007	**242,042**
AGIS - FAN	Equity Return	31,532	33,197	34,722	36,211	38,477	41,066	42,830	44,732	47,454	50,584	54,113	57,136	**512,054**
AGIS - FAN	Current Income Tax Requirement	(21,839)	(20,847)	(19,842)	(18,804)	(17,424)	(15,855)	(14,628)	(13,435)	(11,959)	(10,339)	(8,578)	(7,053)	**(180,604)**
AGIS - FAN	Book Depreciation	61,093	61,885	62,853	63,936	65,093	66,393	67,673	68,728	69,665	70,550	71,389	72,146	**801,406**
AGIS - FAN	AFUDC													
AGIS - FAN	Deferred Taxes	31,270	31,270	31,270	31,270	31,270	31,270	31,270	31,270	31,270	31,270	31,270	31,270	**375,235**
AGIS - FAN	Operating Expenses	34,591	34,591	34,591	34,591	34,591	34,591	34,591	34,591	34,591	34,591	34,591	34,591	**415,089**
AGIS - FAN	Property Tax Expense													
AGIS - FAN	OATT Credit													
AGIS - FAN	Total Revenue Requirement	151,552	155,787	160,006	164,320	170,193	176,875	181,980	187,030	193,452	200,566	208,364	215,096	**2,165,223**
AGIS - FAN	**Rider Revenue Requirement**	135,226	138,923	142,607	146,374	151,500	157,330	161,786	166,194	171,798	178,005	184,808	190,683	**1,925,235**

Project	Rider Components	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
AGIS - ADMS	CWIP Balance	2,782,400	2,891,356	3,000,312	3,150,384	3,300,455	3,450,527	3,600,598	3,906,908	4,213,219	4,519,529	4,774,856	5,140,948	**5,140,948**
AGIS - ADMS	Plant In-Service	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	35,023,823	**35,023,823**
AGIS - ADMS	Depreciation Reserve	6,768,277	7,076,797	7,385,318	7,693,839	8,002,359	8,310,880	8,619,401	8,927,922	9,236,442	9,544,963	9,853,484	10,162,004	**10,162,004**
AGIS - ADMS	Accumulated Deferred Taxes	2,114,647	2,170,501	2,224,582	2,280,436	2,334,517	2,390,372	2,444,453	2,499,420	2,555,274	2,609,355	2,665,209	2,719,290	**2,719,290**
AGIS - ADMS	Average Rate Base	29,023,082	28,767,663	28,514,018	28,279,157	28,066,626	27,852,323	27,639,793	27,504,495	27,446,431	27,390,139	27,306,583	27,254,691	**27,254,691**
AGIS - ADMS	Tax Depreciation Expense	502,437	502,437	502,437	502,437	502,437	502,437	502,437	502,437	502,437	502,437	502,437	502,437	**6,029,239**
AGIS - ADMS	CPI-TAX INTEREST													
AGIS - ADMS	Debt Return	54,418	53,939	53,464	53,023	52,625	52,223	51,825	51,571	51,462	51,357	51,200	51,103	**628,209**
AGIS - ADMS	Equity Return	115,125	114,112	113,106	112,174	111,331	110,481	109,638	109,101	108,871	108,648	108,316	108,110	**1,329,012**
AGIS - ADMS	Current Income Tax Requirement	(9,609)	(10,018)	(10,424)	(10,799)	(11,139)	(11,482)	(11,822)	(12,039)	(12,132)	(12,222)	(12,356)	(12,439)	**(136,481)**
AGIS - ADMS	Book Depreciation	308,521	308,521	308,521	308,521	308,521	308,521	308,521	308,521	308,521	308,521	308,521	308,521	**3,702,248**
AGIS - ADMS	AFUDC													
AGIS - ADMS	Deferred Taxes	54,968	54,968	54,968	54,968	54,968	54,968	54,968	54,968	54,968	54,968	54,968	54,968	**659,611**
AGIS - ADMS	Operating Expenses	46,032	46,032	46,032	46,032	46,032	46,032	46,032	46,032	46,032	46,032	46,032	46,032	**552,388**
AGIS - ADMS	Property Tax Expense													
AGIS - ADMS	OATT Credit													
AGIS - ADMS	Total Revenue Requirement	569,455	567,554	565,666	563,919	562,337	560,742	559,161	558,154	557,722	557,303	556,681	556,295	**6,734,988**
AGIS - ADMS	**Rider Revenue Requirement**	502,225	500,568	498,923	497,400	496,022	494,632	493,254	492,377	492,000	491,636	491,094	490,758	**5,940,888**
AGIS - AMI	CWIP Balance	6,464,068	9,556,907	7,180,639	7,178,444	7,176,250	7,174,055	7,171,861	7,169,667	7,167,472	(41,088)	(42,190)	(40,733)	**(40,733)**
AGIS - AMI	Plant In-Service	89,995,831	98,518,441	110,136,084	118,897,934	127,420,544	135,943,154	144,705,005	153,227,615	161,750,224	177,718,441	184,102,652	192,260,762	**192,260,762**
AGIS - AMI	Depreciation Reserve	3,745,490	4,192,889	4,689,885	5,236,977	5,821,269	6,442,263	7,100,456	7,795,850	8,527,945	9,297,241	10,099,281	10,932,799	**10,932,799**
AGIS - AMI	Accumulated Deferred Taxes	522,545	627,455	729,035	833,945	935,525	1,040,435	1,142,014	1,245,259	1,350,169	1,451,749	1,556,659	1,658,239	**1,658,239**
AGIS - AMI	Average Rate Base	88,017,136	97,670,979	107,525,614	115,899,175	123,871,939	131,684,801	139,583,664	147,443,661	155,145,422	162,933,183	169,613,988	175,965,967	**175,965,967**
AGIS - AMI	Tax Depreciation Expense	1,002,707	1,002,707	1,002,707	1,002,707	1,002,707	1,002,707	1,002,707	1,002,707	1,002,707	1,002,707	1,002,707	1,002,707	**12,032,487**
AGIS - AMI	CPI-TAX INTEREST	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	518	2,026	**15,266**
AGIS - AMI	Debt Return	165,032	183,133	201,611	217,311	232,260	246,909	261,719	276,457	290,898	305,500	318,026	329,936	**3,028,792**
AGIS - AMI	Equity Return	349,135	387,428	426,518	459,733	491,359	522,350	553,682	584,860	615,410	646,302	672,802	697,998	**6,407,577**
AGIS - AMI	Current Income Tax Requirement	(56,008)	(25,558)	10,215	43,818	71,579	98,883	126,525	154,106	181,232	208,697	232,289	255,757	**1,301,534**
AGIS - AMI	Book Depreciation	410,199	447,399	496,996	547,092	584,292	620,994	658,194	695,394	732,095	769,295	802,040	833,518	**7,597,507**
AGIS - AMI	AFUDC													
AGIS - AMI	Deferred Taxes	103,245	103,245	103,245	103,245	103,245	103,245	103,245	103,245	103,245	103,245	103,245	103,245	**1,238,939**
AGIS - AMI	Operating Expenses	1,323,857	1,323,857	1,323,857	1,323,857	1,323,857	1,323,857	1,323,857	1,323,857	1,323,857	1,323,857	1,323,857	1,323,857	**15,886,280**
AGIS - AMI	Property Tax Expense													
AGIS - AMI	OATT Credit													
AGIS - AMI	Total Revenue Requirement	2,295,459	2,419,504	2,562,441	2,695,056	2,806,591	2,916,237	3,027,222	3,137,918	3,246,737	3,356,895	3,452,259	3,544,311	**35,460,629**
AGIS - AMI	**Rider Revenue Requirement**	2,275,418	2,397,402	2,535,619	2,665,007	2,775,988	2,885,083	2,995,519	3,105,668	3,213,943	3,323,559	3,418,384	3,509,901	**35,101,489**
AGIS - FAN	CWIP Balance	7,951,913	8,666,452	9,494,183	10,478,766	11,469,145	12,505,320	13,477,041	14,455,528	15,448,483	16,973,224	18,073,036	19,149,892	**19,149,892**
AGIS - FAN	Plant In-Service	9,875,898	9,915,995	9,942,058	9,959,000	9,970,011	9,999,754	10,019,086	10,031,652	10,039,820	10,045,129	10,048,580	10,942,626	**10,942,626**
AGIS - FAN	Depreciation Reserve	1,309,340	1,382,524	1,455,986	1,529,629	1,603,389	1,677,320	1,751,458	1,825,731	1,900,090	1,974,506	2,048,959	2,127,186	**2,127,186**
AGIS - FAN	Accumulated Deferred Taxes	705,324	729,049	752,022	775,748	798,720	822,446	845,419	868,768	892,493	915,466	939,192	962,164	**962,164**
AGIS - FAN	Average Rate Base	15,237,402	16,130,147	16,838,067	17,668,448	18,573,232	19,509,315	20,440,792	21,334,291	22,232,338	23,400,565	24,619,061	26,056,831	**26,056,831**
AGIS - FAN	Tax Depreciation Expense	157,216	157,216	157,216	157,216	157,216	157,216	157,216	157,216	157,216	157,216	157,216	157,216	**1,886,587**
AGIS - FAN	CPI-TAX INTEREST													
AGIS - FAN	Debt Return	28,570	30,244	31,571	33,128	34,825	36,580	38,326	40,002	41,686	43,876	46,161	48,857	**453,826**
AGIS - FAN	Equity Return	60,442	63,983	66,791	70,085	73,674	77,387	81,082	84,626	88,188	92,822	97,656	103,359	**960,094**
AGIS - FAN	Current Income Tax Requirement	(270)	1,331	2,576	3,977	5,473	7,039	8,613	10,097	11,569	13,461	15,425	19,248	**98,538**
AGIS - FAN	Book Depreciation	72,756	73,184	73,462	73,643	73,760	73,932	74,138	74,272	74,359	74,416	74,453	78,227	**890,601**
AGIS - FAN	AFUDC													
AGIS - FAN	Deferred Taxes	23,349	23,349	23,349	23,349	23,349	23,349	23,349	23,349	23,349	23,349	23,349	23,349	**280,190**
AGIS - FAN	Operating Expenses	71,810	71,810	71,810	71,810	71,810	71,810	71,810	71,810	71,810	71,810	71,810	71,810	**861,719**
AGIS - FAN	Property Tax Expense													
AGIS - FAN	OATT Credit													
AGIS - FAN	Total Revenue Requirement	256,657	263,901	269,559	275,992	282,890	290,097	297,318	304,156	310,961	319,734	328,853	344,849	**3,544,967**
AGIS - FAN	**Rider Revenue Requirement**	231,686	238,005	242,943	248,555	254,573	260,859	267,159	273,123	279,060	286,712	294,665	308,612	**3,185,952**

Project	Rider Components	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
AGIS - LoadSeer	CWIP Balance													
AGIS - LoadSeer	Plant In-Service													
AGIS - LoadSeer	Depreciation Reserve													
AGIS - LoadSeer	Accumulated Deferred Taxes													
AGIS - LoadSeer	Average Rate Base													
AGIS - LoadSeer	Tax Depreciation Expense													
AGIS - LoadSeer	CPI-TAX INTEREST													
AGIS - LoadSeer	Debt Return													
AGIS - LoadSeer	Equity Return													
AGIS - LoadSeer	Current Income Tax Requirement													
AGIS - LoadSeer	Book Depreciation													
AGIS - LoadSeer	AFUDC													
AGIS - LoadSeer	Deferred Taxes													
AGIS - LoadSeer	Operating Expenses													
AGIS - LoadSeer	Property Tax Expense													
AGIS - LoadSeer	OATT Credit													
AGIS - LoadSeer	Total Revenue Requirement													
AGIS - LoadSeer	**Rider Revenue Requirement**													
AGIS - TOU Pilot	CWIP Balance	5,374	9,332	50,015	67,113	79,685	264,788	299,226	375,070	858,810	2,731,772	1,058,365	1,413,712	**1,413,712**
AGIS - TOU Pilot	Plant In-Service											2,796,743	3,335,788	**3,335,788**
AGIS - TOU Pilot	Depreciation Reserve											2,482	7,925	**7,925**
AGIS - TOU Pilot	Accumulated Deferred Taxes	2,215	4,429	6,644	8,859	11,073	13,288	15,503	17,717	19,932	22,147	24,361	26,576	**26,576**
AGIS - TOU Pilot	Average Rate Base	4,243	4,031	24,136	50,812	63,433	160,055	267,611	320,538	598,115	1,774,252	3,268,945	4,271,631	**4,271,631**
AGIS - TOU Pilot	Tax Depreciation Expense	10,410	10,410	10,410	10,410	10,410	10,410	10,410	10,410	10,410	10,410	10,410	10,410	**124,922**
AGIS - TOU Pilot	CPI-TAX INTEREST						1,129	866	974	1,200	13,812	9,800	13,059	**40,840**
AGIS - TOU Pilot	Debt Return	8	8	45	95	119	300	502	601	1,121	3,327	6,129	8,009	**20,265**
AGIS - TOU Pilot	Equity Return	17	16	96	202	252	635	1,062	1,271	2,373	7,038	12,967	16,944	**42,871**
AGIS - TOU Pilot	Current Income Tax Requirement	(3,299)	(3,299)	(3,267)	(3,224)	(3,204)	(2,594)	(2,528)	(2,400)	(1,865)	5,104	6,879	10,991	**(2,706)**
AGIS - TOU Pilot	Book Depreciation											2,482	5,443	**7,925**
AGIS - TOU Pilot	AFUDC			67	127	145	2,004	1,950	2,131	2,845	10,154	15,698	20,966	**56,085**
AGIS - TOU Pilot	Deferred Taxes	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	2,215	**26,576**
AGIS - TOU Pilot	Operating Expenses													
AGIS - TOU Pilot	Property Tax Expense													
AGIS - TOU Pilot	OATT Credit													
AGIS - TOU Pilot	Total Revenue Requirement	(1,059)	(1,061)	(845)	(586)	(474)	2,559	3,199	3,818	6,689	27,837	46,370	64,568	**151,016**
AGIS - TOU Pilot	**Rider Revenue Requirement**													
Big Stone-Brookings	CWIP Balance	331,893	330,064	327,304	325,390	324,943	410,740	421,971	421,787	421,971	421,971	421,971	421,971	**421,971**
Big Stone-Brookings	Plant In-Service	54,100,546	54,102,761	54,108,918	54,110,729	54,104,928	54,107,985	54,107,985	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	**54,108,171**
Big Stone-Brookings	Depreciation Reserve	1,540,633	1,636,035	1,731,444	1,826,859	1,922,272	2,017,681	2,113,094	2,208,506	2,303,919	2,399,332	2,494,745	2,590,157	**2,590,157**
Big Stone-Brookings	Accumulated Deferred Taxes	11,583,292	11,628,515	11,673,739	11,718,963	11,764,187	11,809,411	11,854,635	11,899,858	11,945,082	11,990,306	12,035,530	12,080,754	**12,080,754**
Big Stone-Brookings	Average Rate Base	41,375,008	41,238,394	41,099,657	40,960,668	40,816,855	40,717,523	40,626,931	40,491,910	40,351,366	40,210,822	40,070,185	39,929,549	**39,929,549**
Big Stone-Brookings	Tax Depreciation Expense	256,912	256,912	256,912	256,912	256,912	256,912	256,912	256,912	256,912	256,912	256,912	256,912	**3,082,945**
Big Stone-Brookings	CPI-TAX INTEREST													
Big Stone-Brookings	Debt Return	77,578	77,322	77,062	76,801	76,532	76,345	76,175	75,922	75,659	75,395	75,132	74,868	**914,792**
Big Stone-Brookings	Equity Return	164,121	163,579	163,029	162,477	161,907	161,513	161,153	160,618	160,060	159,503	158,945	158,387	**1,935,293**
Big Stone-Brookings	Current Income Tax Requirement	19,290	19,075	18,856	18,637	18,405	18,245	18,101	17,885	17,661	17,436	17,211	16,986	**217,789**
Big Stone-Brookings	Book Depreciation	95,391	95,402	95,409	95,416	95,412	95,410	95,412	95,413	95,413	95,413	95,413	95,413	**1,144,915**
Big Stone-Brookings	AFUDC													
Big Stone-Brookings	Deferred Taxes	45,224	45,224	45,224	45,224	45,224	45,224	45,224	45,224	45,224	45,224	45,224	45,224	**542,686**
Big Stone-Brookings	Property Tax Expense	69,459	69,459	69,459	69,459	69,459	69,459	69,459	69,459	69,459	69,459	69,459	69,459	**833,514**
Big Stone-Brookings	OATT Credit													
Big Stone-Brookings	Total Revenue Requirement	471,063	470,061	469,039	468,014	466,939	466,197	465,526	464,522	463,476	462,430	461,384	460,337	**5,588,987**
Big Stone-Brookings	**Rider Revenue Requirement**	345,155	344,421	343,672	342,921	342,133	341,589	341,098	340,362	339,596	338,829	338,063	337,296	**4,095,135**

Project	Rider Components	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
AGIS - LoadSeer	CWIP Balance		45,753	98,037	147,990	755,942	839,895	897,977	1,017,231	2,016,318	2,024,724	2,028,568		
AGIS - LoadSeer	Plant In-Service												2,587,275	**2,587,275**
AGIS - LoadSeer	Depreciation Reserve												22,668	**22,668**
AGIS - LoadSeer	Accumulated Deferred Taxes	9,546	19,091	23,710	33,410	42,801	52,501	61,892	71,438	81,138	90,529	100,229	109,621	**109,621**
AGIS - LoadSeer	Average Rate Base	(4,773)	3,785	48,185	89,604	409,165	745,417	807,043	886,166	1,435,637	1,929,992	1,926,417	2,186,967	**2,186,967**
AGIS - LoadSeer	Tax Depreciation Expense	35,942	35,942	35,942	35,942	35,942	35,942	35,942	35,942	35,942	35,942	35,942	35,942	**431,299**
AGIS - LoadSeer	CPI-TAX INTEREST													
AGIS - LoadSeer	Debt Return	(9)	7	90	168	767	1,398	1,513	1,662	2,692	3,619	3,612	4,101	**19,619**
AGIS - LoadSeer	Equity Return	(19)	15	191	355	1,623	2,957	3,201	3,515	5,695	7,656	7,641	8,675	**41,506**
AGIS - LoadSeer	Current Income Tax Requirement	(10,654)	(10,641)	(10,570)	(10,503)	(9,992)	(9,454)	(9,356)	(9,229)	(8,350)	(7,559)	(7,565)	1,996	**(101,877)**
AGIS - LoadSeer	Book Depreciation												22,668	**22,668**
AGIS - LoadSeer	AFUDC													
AGIS - LoadSeer	Deferred Taxes	9,546	9,546	9,546	9,546	9,546	9,546	9,546	9,546	9,546	9,546	9,546	9,546	**114,547**
AGIS - LoadSeer	Operating Expenses	2,153	6,568	13,833	13,826	10,268	8,338	9,047	18,093	27,956	19,225	11,760	4,821	**145,886**
AGIS - LoadSeer	Property Tax Expense													
AGIS - LoadSeer	OATT Credit													
AGIS - LoadSeer	Total Revenue Requirement	1,016	5,495	13,091	13,392	12,212	12,784	13,951	23,586	37,538	32,486	24,994	51,805	**242,349**
AGIS - LoadSeer	**Rider Revenue Requirement**	1,160	5,631	13,185	13,447	11,965	12,220	13,329	22,889	36,322	30,803	23,315	45,843	**230,108**
AGIS - TOU Pilot	CWIP Balance	925,171	1,382,247	1,936,953	477,176	438,475	447,453	447,949	447,945	452,999	1,067,799	1,013,939	(33,631)	**(33,631)**
AGIS - TOU Pilot	Plant In-Service	3,439,922	3,439,922	3,439,922	4,603,278	4,600,208	4,600,208	4,600,208	4,600,208	4,599,511	4,047,681	4,104,425	5,160,621	**5,160,621**
AGIS - TOU Pilot	Depreciation Reserve	16,077	24,355	32,632	42,309	53,382	64,451	75,520	86,590	97,658	108,062	118,038	132,408	**132,408**
AGIS - TOU Pilot	Accumulated Deferred Taxes	33,328	40,080	46,831	53,583	60,335	67,086	73,838	80,590	87,342	94,093	100,845	107,597	**107,597**
AGIS - TOU Pilot	Average Rate Base	4,515,343	4,533,336	5,024,198	5,137,611	4,951,388	4,917,169	4,904,084	4,886,509	4,870,865	4,887,041	4,903,027	4,889,858	**4,889,858**
AGIS - TOU Pilot	Tax Depreciation Expense	35,355	35,355	35,355	35,355	35,355	35,355	35,355	35,355	35,355	35,355	35,355	35,355	**424,261**
AGIS - TOU Pilot	CPI-TAX INTEREST	13,735	(31,694)								36,912		1,853	**20,806**
AGIS - TOU Pilot	Debt Return	8,466	8,500	9,420	9,633	9,284	9,220	9,195	9,162	9,133	9,163	9,193	9,168	**109,538**
AGIS - TOU Pilot	Equity Return	17,911	17,982	19,929	20,379	19,641	19,505	19,453	19,383	19,321	19,385	19,449	19,396	**231,734**
AGIS - TOU Pilot	Current Income Tax Requirement	4,515	(13,729)	(160)	586	851	795	774	746	720	15,367	331	2,830	**13,626**
AGIS - TOU Pilot	Book Depreciation	8,152	8,277	8,277	9,677	11,073	11,069	11,069	11,069	11,068	10,404	9,976	14,370	**124,483**
AGIS - TOU Pilot	AFUDC	22,655	(51,050)	156	333	(3,445)	(167)				59,058	405	3,995	**31,941**
AGIS - TOU Pilot	Deferred Taxes	6,752	6,752	6,752	6,752	6,752	6,752	6,752	6,752	6,752	6,752	6,752	6,752	**81,021**
AGIS - TOU Pilot	Operating Expenses													
AGIS - TOU Pilot	Property Tax Expense													
AGIS - TOU Pilot	OATT Credit													
AGIS - TOU Pilot	Total Revenue Requirement	68,451	(23,268)	44,374	47,360	44,156	47,173	47,243	47,112	46,995	120,129	46,106	56,512	**592,344**
AGIS - TOU Pilot	**Rider Revenue Requirement**													
Big Stone-Brookings	CWIP Balance	421,971	421,971	421,971	421,971	421,971	421,971	421,972	421,972	421,972	421,972	421,972	421,972	**421,972**
Big Stone-Brookings	Plant In-Service	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	**54,108,171**
Big Stone-Brookings	Depreciation Reserve	2,685,335	2,780,513	2,875,690	2,970,868	3,066,045	3,161,223	3,256,401	3,351,578	3,446,756	3,541,934	3,637,111	3,732,289	**3,732,289**
Big Stone-Brookings	Accumulated Deferred Taxes	12,122,050	12,163,347	12,183,329	12,225,292	12,265,923	12,307,886	12,348,516	12,389,813	12,431,776	12,472,407	12,514,369	12,555,000	**12,555,000**
Big Stone-Brookings	Average Rate Base	39,790,993	39,633,871	39,518,711	39,381,570	39,245,762	39,108,621	38,972,814	38,836,340	38,699,199	38,563,391	38,426,250	38,290,442	**38,290,442**
Big Stone-Brookings	Tax Depreciation Expense	242,493	242,493	242,493	242,493	242,493	242,493	242,493	242,493	242,493	242,493	242,493	242,493	**2,909,914**
Big Stone-Brookings	CPI-TAX INTEREST													
Big Stone-Brookings	Debt Return	74,608	74,314	74,098	73,840	73,586	73,329	73,074	72,818	72,561	72,306	72,049	71,795	**878,377**
Big Stone-Brookings	Equity Return	157,838	157,214	156,758	156,214	155,675	155,131	154,592	154,051	153,507	152,968	152,424	151,885	**1,858,256**
Big Stone-Brookings	Current Income Tax Requirement	20,901	20,650	20,466	20,246	20,029	19,810	19,592	19,374	19,154	18,937	18,718	18,500	**236,378**
Big Stone-Brookings	Book Depreciation	95,178	95,178	95,178	95,178	95,178	95,178	95,178	95,178	95,178	95,178	95,178	95,178	**1,142,132**
Big Stone-Brookings	AFUDC													
Big Stone-Brookings	Deferred Taxes	41,297	41,297	41,297	41,297	41,297	41,297	41,297	41,297	41,297	41,297	41,297	41,297	**495,561**
Big Stone-Brookings	Property Tax Expense	67,915	67,915	67,915	67,915	67,915	67,915	67,915	67,915	67,915	67,915	67,915	67,915	**814,974**
Big Stone-Brookings	OATT Credit													
Big Stone-Brookings	Total Revenue Requirement	457,736	456,567	455,710	454,689	453,679	452,658	451,647	450,632	449,611	448,601	447,580	446,569	**5,425,678**
Big Stone-Brookings	**Rider Revenue Requirement**	335,262	334,405	333,778	333,030	332,290	331,542	330,802	330,058	329,311	328,571	327,823	327,083	**3,973,954**

Project	Rider Components	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
AGIS - LoadSeer	CWIP Balance													
AGIS - LoadSeer	Plant In-Service	2,766,275	2,762,101	2,768,011	2,768,011	2,768,035	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	**2,768,034**
AGIS - LoadSeer	Depreciation Reserve	66,778	112,328	157,892	203,505	249,118	294,731	340,344	385,958	431,571	477,184	522,798	568,411	**568,411**
AGIS - LoadSeer	Accumulated Deferred Taxes	118,597	126,697	134,796	142,896	150,995	159,095	167,195	175,294	183,394	191,493	199,593	207,693	**207,693**
AGIS - LoadSeer	Average Rate Base	2,513,455	2,547,939	2,495,150	2,444,417	2,390,716	2,337,015	2,283,302	2,229,589	2,175,876	2,122,163	2,068,451	2,014,738	**2,014,738**
AGIS - LoadSeer	Tax Depreciation Expense	74,373	74,373	74,373	74,373	74,373	74,373	74,373	74,373	74,373	74,373	74,373	74,373	**892,471**
AGIS - LoadSeer	CPI-TAX INTEREST													
AGIS - LoadSeer	Debt Return	4,713	4,777	4,678	4,583	4,483	4,382	4,281	4,180	4,080	3,979	3,878	3,778	**51,793**
AGIS - LoadSeer	Equity Return	9,970	10,107	9,897	9,696	9,483	9,270	9,057	8,844	8,631	8,418	8,205	7,992	**109,570**
AGIS - LoadSeer	Current Income Tax Requirement	(4,918)	(4,282)	(4,361)	(4,422)	(4,508)	(4,594)	(4,680)	(4,766)	(4,852)	(4,938)	(5,024)	(5,110)	**(56,454)**
AGIS - LoadSeer	Book Depreciation	44,109	45,550	45,564	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	**545,743**
AGIS - LoadSeer	AFUDC													
AGIS - LoadSeer	Deferred Taxes	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	8,100	**97,195**
AGIS - LoadSeer	Operating Expenses	5,521	181,512	(163,376)	6,207	6,317	4,419	8,421	7,978	7,660	7,732	7,768	8,066	**88,225**
AGIS - LoadSeer	Property Tax Expense													
AGIS - LoadSeer	OATT Credit													
AGIS - LoadSeer	Total Revenue Requirement	67,495	245,764	(99,497)	69,776	69,487	67,190	70,792	69,949	69,232	68,904	68,540	68,439	**836,071**
AGIS - LoadSeer	**Rider Revenue Requirement**	59,544	237,521	(107,692)	61,621	61,383	59,137	62,790	61,999	61,333	61,056	60,744	60,693	**740,129**
AGIS - TOU Pilot	CWIP Balance	(34,805)	(34,547)	(34,547)	(34,415)	(34,415)	(34,415)							
AGIS - TOU Pilot	Plant In-Service	5,160,621	5,160,621	5,160,621	5,160,621	5,160,621	5,160,621	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	**5,126,206**
AGIS - TOU Pilot	Depreciation Reserve	151,487	170,566	189,644	208,723	227,802	246,881	265,808	284,584	303,359	322,135	340,911	359,686	**359,686**
AGIS - TOU Pilot	Accumulated Deferred Taxes	114,994	122,391	129,788	137,185	144,582	151,979	159,377	166,774	174,171	181,568	188,965	196,362	**196,362**
AGIS - TOU Pilot	Average Rate Base	4,869,462	4,842,528	4,816,181	4,789,771	4,763,361	4,736,885	4,710,485	4,684,237	4,658,064	4,631,891	4,605,718	4,579,546	**4,579,546**
AGIS - TOU Pilot	Tax Depreciation Expense	44,763	44,763	44,763	44,763	44,763	44,763	44,763	44,763	44,763	44,763	44,763	44,763	**537,161**
AGIS - TOU Pilot	CPI-TAX INTEREST													
AGIS - TOU Pilot	Debt Return	9,130	9,080	9,030	8,981	8,931	8,882	8,832	8,783	8,734	8,685	8,636	8,587	**106,290**
AGIS - TOU Pilot	Equity Return	19,316	19,209	19,104	18,999	18,895	18,790	18,685	18,581	18,477	18,373	18,269	18,166	**224,863**
AGIS - TOU Pilot	Current Income Tax Requirement	415	372	329	287	245	203	99	(4)	(46)	(88)	(130)	(171)	**1,511**
AGIS - TOU Pilot	Book Depreciation	19,079	19,079	19,079	19,079	19,079	19,079	18,927	18,776	18,776	18,776	18,776	18,776	**227,278**
AGIS - TOU Pilot	AFUDC													
AGIS - TOU Pilot	Deferred Taxes	7,397	7,397	7,397	7,397	7,397	7,397	7,397	7,397	7,397	7,397	7,397	7,397	**88,765**
AGIS - TOU Pilot	Operating Expenses													
AGIS - TOU Pilot	Property Tax Expense													
AGIS - TOU Pilot	OATT Credit													
AGIS - TOU Pilot	Total Revenue Requirement	55,336	55,136	54,940	54,743	54,547	54,350	53,941	53,533	53,338	53,143	52,948	52,753	**648,707**
AGIS - TOU Pilot	**Rider Revenue Requirement**													
Big Stone-Brookings	CWIP Balance	421,972	421,972	421,972	421,972	421,972	421,972	421,971	421,971	421,971	421,971	421,971	421,971	**421,971**
Big Stone-Brookings	Plant In-Service	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	**54,108,171**
Big Stone-Brookings	Depreciation Reserve	3,827,319	3,922,349	4,017,379	4,112,409	4,207,439	4,302,469	4,397,499	4,492,529	4,587,559	4,682,589	4,777,619	4,872,649	**4,872,649**
Big Stone-Brookings	Accumulated Deferred Taxes	12,595,096	12,632,658	12,670,220	12,707,782	12,745,344	12,782,906	12,820,468	12,858,030	12,895,592	12,933,155	12,970,717	13,008,279	**13,008,279**
Big Stone-Brookings	Average Rate Base	38,155,243	38,022,651	37,890,058	37,757,466	37,624,874	37,492,282	37,359,690	37,227,098	37,094,506	36,961,913	36,829,321	36,696,729	**36,696,729**
Big Stone-Brookings	Tax Depreciation Expense	229,022	229,022	229,022	229,022	229,022	229,022	229,022	229,022	229,022	229,022	229,022	229,022	**2,748,270**
Big Stone-Brookings	CPI-TAX INTEREST													
Big Stone-Brookings	Debt Return	71,541	71,292	71,044	70,795	70,547	70,298	70,049	69,801	69,552	69,304	69,055	68,806	**842,085**
Big Stone-Brookings	Equity Return	151,349	150,823	150,297	149,771	149,245	148,719	148,193	147,667	147,142	146,616	146,090	145,564	**1,781,477**
Big Stone-Brookings	Current Income Tax Requirement	22,152	21,939	21,727	21,515	21,303	21,091	20,879	20,667	20,454	20,242	20,030	19,818	**251,817**
Big Stone-Brookings	Book Depreciation	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	**1,140,361**
Big Stone-Brookings	AFUDC													
Big Stone-Brookings	Deferred Taxes	37,562	37,562	37,562	37,562	37,562	37,562	37,562	37,562	37,562	37,562	37,562	37,562	**450,745**
Big Stone-Brookings	Property Tax Expense	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	**802,317**
Big Stone-Brookings	OATT Credit													
Big Stone-Brookings	Total Revenue Requirement	444,494	443,507	442,520	441,534	440,547	439,560	438,573	437,587	436,600	435,613	434,627	433,640	**5,268,801**
Big Stone-Brookings	**Rider Revenue Requirement**	324,880	324,159	323,438	322,717	321,996	321,274	320,553	319,832	319,111	318,390	317,669	316,947	**3,850,967**

Project	Rider Components	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
AGIS - LoadSeer	CWIP Balance													
AGIS - LoadSeer	Plant In-Service	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	**2,768,034**
AGIS - LoadSeer	Depreciation Reserve	614,024	659,637	705,251	750,864	796,477	842,091	887,704	933,317	978,930	1,024,544	1,070,157	1,115,770	**1,115,770**
AGIS - LoadSeer	Accumulated Deferred Taxes	216,125	224,890	233,656	242,421	251,186	259,951	268,575	277,341	286,247	294,871	303,778	312,402	**312,402**
AGIS - LoadSeer	Average Rate Base	1,960,692	1,906,313	1,851,935	1,797,556	1,743,178	1,688,799	1,634,562	1,580,183	1,525,663	1,471,426	1,416,906	1,362,669	**1,362,669**
AGIS - LoadSeer	Tax Depreciation Expense	76,882	76,882	76,882	76,882	76,882	76,882	76,882	76,882	76,882	76,882	76,882	76,882	**922,586**
AGIS - LoadSeer	CPI-TAX INTEREST													
AGIS - LoadSeer	Debt Return	3,676	3,574	3,472	3,370	3,268	3,166	3,065	2,963	2,861	2,759	2,657	2,555	**37,387**
AGIS - LoadSeer	Equity Return	7,777	7,562	7,346	7,130	6,915	6,699	6,484	6,268	6,052	5,837	5,620	5,405	**79,095**
AGIS - LoadSeer	Current Income Tax Requirement	(5,940)	(6,027)	(6,114)	(6,201)	(6,288)	(6,375)	(6,462)	(6,549)	(6,636)	(6,723)	(6,810)	(6,897)	**(77,019)**
AGIS - LoadSeer	Book Depreciation	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	**547,359**
AGIS - LoadSeer	AFUDC													
AGIS - LoadSeer	Deferred Taxes	8,765	8,765	8,765	8,765	8,765	8,765	8,765	8,765	8,765	8,765	8,765	8,765	**105,183**
AGIS - LoadSeer	Operating Expenses	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	5,760	**69,126**
AGIS - LoadSeer	Property Tax Expense													
AGIS - LoadSeer	OATT Credit													
AGIS - LoadSeer	Total Revenue Requirement	65,653	65,248	64,844	64,439	64,034	63,630	63,226	62,821	62,416	62,012	61,606	61,203	**761,132**
AGIS - LoadSeer	**Rider Revenue Requirement**	57,969	57,617	57,264	56,911	56,558	56,206	55,854	55,501	55,147	54,795	54,442	54,090	**672,353**
AGIS - TOU Pilot	CWIP Balance													
AGIS - TOU Pilot	Plant In-Service	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	**5,126,206**
AGIS - TOU Pilot	Depreciation Reserve	378,462	397,238	416,013	434,789	453,565	472,340	491,116	509,892	528,667	547,443	566,218	584,994	**584,994**
AGIS - TOU Pilot	Accumulated Deferred Taxes	198,956	204,145	209,334	214,523	219,712	224,901	230,006	235,194	240,467	245,572	250,845	255,950	**255,950**
AGIS - TOU Pilot	Average Rate Base	4,558,175	4,534,211	4,510,247	4,486,282	4,462,318	4,438,353	4,414,472	4,390,508	4,366,460	4,342,579	4,318,531	4,294,650	**4,294,650**
AGIS - TOU Pilot	Tax Depreciation Expense	36,522	36,522	36,522	36,522	36,522	36,522	36,522	36,522	36,522	36,522	36,522	36,522	**438,261**
AGIS - TOU Pilot	CPI-TAX INTEREST													
AGIS - TOU Pilot	Debt Return	8,547	8,502	8,457	8,412	8,367	8,322	8,277	8,232	8,187	8,142	8,097	8,052	**99,594**
AGIS - TOU Pilot	Equity Return	18,081	17,986	17,891	17,796	17,701	17,605	17,511	17,416	17,320	17,226	17,130	17,035	**210,697**
AGIS - TOU Pilot	Current Income Tax Requirement	2,228	2,190	2,151	2,113	2,075	2,036	1,998	1,960	1,921	1,883	1,844	1,806	**24,205**
AGIS - TOU Pilot	Book Depreciation	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	**225,308**
AGIS - TOU Pilot	AFUDC													
AGIS - TOU Pilot	Deferred Taxes	5,189	5,189	5,189	5,189	5,189	5,189	5,189	5,189	5,189	5,189	5,189	5,189	**62,266**
AGIS - TOU Pilot	Operating Expenses	8,437	8,437	8,437	8,437	8,437	8,437	8,437	8,437	8,437	8,437	8,437	8,437	**101,245**
AGIS - TOU Pilot	Property Tax Expense													
AGIS - TOU Pilot	OATT Credit													
AGIS - TOU Pilot	Total Revenue Requirement	61,257	61,078	60,900	60,722	60,543	60,365	60,187	60,009	59,830	59,652	59,473	59,296	**723,314**
AGIS - TOU Pilot	**Rider Revenue Requirement**	59,231	59,063	58,896	58,728	58,560	58,392	58,225	58,057	57,889	57,722	57,553	57,386	**699,701**
Big Stone-Brookings	CWIP Balance	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	**421,971**
Big Stone-Brookings	Plant In-Service	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	**54,108,171**
Big Stone-Brookings	Depreciation Reserve	4,967,679	5,062,710	5,157,740	5,252,770	5,347,800	5,442,830	5,537,860	5,632,890	5,727,920	5,822,950	5,917,980	6,013,010	**6,013,010**
Big Stone-Brookings	Accumulated Deferred Taxes	13,044,124	13,078,252	13,112,381	13,146,509	13,180,637	13,214,766	13,248,343	13,282,472	13,317,150	13,350,728	13,385,407	13,418,985	**13,418,985**
Big Stone-Brookings	Average Rate Base	36,565,854	36,436,695	36,307,537	36,178,379	36,049,220	35,920,062	35,791,454	35,662,296	35,532,587	35,403,979	35,274,270	35,145,662	**35,145,662**
Big Stone-Brookings	Tax Depreciation Expense	216,773	216,773	216,773	216,773	216,773	216,773	216,773	216,773	216,773	216,773	216,773	216,773	**2,601,275**
Big Stone-Brookings	CPI-TAX INTEREST													
Big Stone-Brookings	Debt Return	68,561	68,319	68,077	67,834	67,592	67,350	67,109	66,867	66,624	66,382	66,139	65,898	**806,752**
Big Stone-Brookings	Equity Return	145,045	144,532	144,020	143,508	142,995	142,483	141,973	141,460	140,946	140,436	139,921	139,411	**1,706,730**
Big Stone-Brookings	Current Income Tax Requirement	23,164	22,958	22,751	22,545	22,338	22,131	21,925	21,719	21,511	21,306	21,098	20,892	**264,338**
Big Stone-Brookings	Book Depreciation	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	**1,140,361**
Big Stone-Brookings	AFUDC													
Big Stone-Brookings	Deferred Taxes	34,128	34,128	34,128	34,128	34,128	34,128	34,128	34,128	34,128	34,128	34,128	34,128	**409,540**
Big Stone-Brookings	Property Tax Expense	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	**802,317**
Big Stone-Brookings	OATT Credit													
Big Stone-Brookings	Total Revenue Requirement	432,788	431,827	430,866	429,905	428,943	427,982	427,025	426,064	425,099	424,142	423,177	422,220	**5,130,037**
Big Stone-Brookings	**Rider Revenue Requirement**	316,585	315,882	315,179	314,476	313,773	313,069	312,369	311,666	310,960	310,260	309,554	308,854	**3,752,627**

Project	Rider Components	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
AGIS - LoadSeer	CWIP Balance													
AGIS - LoadSeer	Plant In-Service	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	2,768,034	**2,768,034**
AGIS - LoadSeer	Depreciation Reserve	1,161,384	1,206,997	1,252,610	1,298,223	1,343,837	1,389,450	1,435,063	1,480,677	1,526,290	1,571,903	1,617,516	1,663,130	**1,663,130**
AGIS - LoadSeer	Accumulated Deferred Taxes	316,295	314,970	313,687	312,362	311,080	309,755	308,472	307,168	305,843	304,561	303,236	301,953	**301,953**
AGIS - LoadSeer	Average Rate Base	1,313,163	1,268,874	1,224,544	1,180,255	1,135,925	1,091,636	1,047,306	1,002,996	958,708	914,377	870,089	825,758	**825,758**
AGIS - LoadSeer	Tax Depreciation Expense	40,962	40,962	40,962	40,962	40,962	40,962	40,962	40,962	40,962	40,962	40,962	40,962	**491,546**
AGIS - LoadSeer	CPI-TAX INTEREST													
AGIS - LoadSeer	Debt Return	2,462	2,379	2,296	2,213	2,130	2,047	1,964	1,881	1,798	1,714	1,631	1,548	**24,063**
AGIS - LoadSeer	Equity Return	5,209	5,033	4,857	4,682	4,506	4,330	4,154	3,979	3,803	3,627	3,451	3,276	**50,907**
AGIS - LoadSeer	Current Income Tax Requirement	3,451	3,380	3,309	3,239	3,168	3,097	3,026	2,955	2,884	2,813	2,742	2,671	**36,735**
AGIS - LoadSeer	Book Depreciation	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	45,613	**547,359**
AGIS - LoadSeer	AFUDC													
AGIS - LoadSeer	Deferred Taxes	(1,304)	(1,304)	(1,304)	(1,304)	(1,304)	(1,304)	(1,304)	(1,304)	(1,304)	(1,304)	(1,304)	(1,304)	**(15,646)**
AGIS - LoadSeer	Operating Expenses	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	5,386	**64,635**
AGIS - LoadSeer	Property Tax Expense													
AGIS - LoadSeer	OATT Credit													
AGIS - LoadSeer	Total Revenue Requirement	60,818	60,488	60,158	59,829	59,499	59,169	58,840	58,510	58,180	57,850	57,521	57,191	**708,053**
AGIS - LoadSeer	**Rider Revenue Requirement**	53,707	53,419	53,132	52,844	52,557	52,269	51,982	51,694	51,407	51,120	50,832	50,545	**625,508**
AGIS - TOU Pilot	CWIP Balance													
AGIS - TOU Pilot	Plant In-Service	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	5,126,206	**5,126,206**
AGIS - TOU Pilot	Depreciation Reserve	603,770	622,545	641,321	660,097	678,872	697,648	716,424	735,199	753,975	772,751	791,526	810,302	**810,302**
AGIS - TOU Pilot	Accumulated Deferred Taxes	260,281	263,753	267,115	270,586	273,948	277,420	280,782	284,198	287,670	291,032	294,504	297,865	**297,865**
AGIS - TOU Pilot	Average Rate Base	4,271,543	4,249,295	4,227,158	4,204,911	4,182,773	4,160,526	4,138,388	4,116,196	4,093,949	4,071,811	4,049,564	4,027,426	**4,027,426**
AGIS - TOU Pilot	Tax Depreciation Expense	30,200	30,200	30,200	30,200	30,200	30,200	30,200	30,200	30,200	30,200	30,200	30,200	**362,403**
AGIS - TOU Pilot	CPI-TAX INTEREST													
AGIS - TOU Pilot	Debt Return	8,009	7,967	7,926	7,884	7,843	7,801	7,759	7,718	7,676	7,635	7,593	7,551	**93,363**
AGIS - TOU Pilot	Equity Return	16,944	16,856	16,768	16,679	16,592	16,503	16,416	16,328	16,239	16,152	16,063	15,975	**197,514**
AGIS - TOU Pilot	Current Income Tax Requirement	3,604	3,569	3,533	3,498	3,462	3,427	3,391	3,356	3,320	3,285	3,249	3,214	**40,908**
AGIS - TOU Pilot	Book Depreciation	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	18,776	**225,308**
AGIS - TOU Pilot	AFUDC													
AGIS - TOU Pilot	Deferred Taxes	3,417	3,417	3,417	3,417	3,417	3,417	3,417	3,417	3,417	3,417	3,417	3,417	**41,001**
AGIS - TOU Pilot	Operating Expenses	7,660	7,660	7,660	7,660	7,660	7,660	7,660	7,660	7,660	7,660	7,660	7,660	**91,922**
AGIS - TOU Pilot	Property Tax Expense													
AGIS - TOU Pilot	OATT Credit													
AGIS - TOU Pilot	Total Revenue Requirement	58,410	58,244	58,080	57,914	57,749	57,584	57,419	57,254	57,088	56,923	56,758	56,593	**690,016**
AGIS - TOU Pilot	**Rider Revenue Requirement**	56,504	56,348	56,192	56,036	55,880	55,724	55,569	55,413	55,257	55,101	54,945	54,789	**667,758**
Big Stone-Brookings	CWIP Balance	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	421,971	**421,971**
Big Stone-Brookings	Plant In-Service	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	54,108,171	**54,108,171**
Big Stone-Brookings	Depreciation Reserve	6,108,040	6,203,070	6,298,100	6,393,130	6,488,160	6,583,190	6,678,220	6,773,250	6,868,280	6,963,310	7,058,341	7,153,371	**7,153,371**
Big Stone-Brookings	Accumulated Deferred Taxes	13,437,647	13,439,847	13,441,978	13,444,178	13,446,309	13,448,509	13,450,639	13,452,804	13,455,005	13,457,135	13,459,335	13,461,466	**13,461,466**
Big Stone-Brookings	Average Rate Base	35,031,970	34,934,740	34,837,579	34,740,349	34,643,189	34,545,958	34,448,798	34,351,602	34,254,372	34,157,212	34,059,981	33,962,821	**33,962,821**
Big Stone-Brookings	Tax Depreciation Expense	103,623	103,623	103,623	103,623	103,623	103,623	103,623	103,623	103,623	103,623	103,623	103,623	**1,243,472**
Big Stone-Brookings	CPI-TAX INTEREST													
Big Stone-Brookings	Debt Return	65,685	65,503	65,320	65,138	64,956	64,774	64,591	64,409	64,227	64,045	63,862	63,680	**776,191**
Big Stone-Brookings	Equity Return	138,960	138,574	138,189	137,803	137,418	137,032	136,647	136,261	135,876	135,490	135,105	134,719	**1,642,075**
Big Stone-Brookings	Current Income Tax Requirement	53,457	53,302	53,146	52,991	52,835	52,680	52,524	52,369	52,213	52,058	51,902	51,747	**631,224**
Big Stone-Brookings	Book Depreciation	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	95,030	**1,140,361**
Big Stone-Brookings	AFUDC													
Big Stone-Brookings	Deferred Taxes	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	2,165	**25,984**
Big Stone-Brookings	Property Tax Expense	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	66,860	**802,317**
Big Stone-Brookings	OATT Credit													
Big Stone-Brookings	Total Revenue Requirement	422,157	421,434	420,711	419,987	419,264	418,541	417,818	417,094	416,371	415,648	414,924	414,201	**5,018,151**
Big Stone-Brookings	**Rider Revenue Requirement**	308,293	307,765	307,237	306,709	306,181	305,652	305,124	304,596	304,068	303,540	303,011	302,483	**3,664,659**

Project	Rider Components	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
CAPX2020 - Brookings	CWIP Balance	2,582	2,582	2,582	2,582	2,582	2,582	2,582	2,582	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - Brookings	Plant In-Service	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	**462,892,932**
CAPX2020 - Brookings	Depreciation Reserve	39,879,132	40,662,661	41,446,190	42,229,719	43,013,248	43,796,777	44,580,306	45,363,836	46,147,365	46,930,894	47,714,423	48,497,952	**48,497,952**
CAPX2020 - Brookings	Accumulated Deferred Taxes	97,075,618	97,371,149	97,666,679	97,962,210	98,257,740	98,553,270	98,848,801	99,144,331	99,439,862	99,735,392	100,030,923	100,326,453	**100,326,453**
CAPX2020 - Brookings	Average Rate Base	322,187,943	325,401,233	324,322,174	323,243,114	322,164,055	321,084,996	320,005,936	318,926,877	317,846,526	316,766,176	315,687,116	314,608,057	**314,608,057**
CAPX2020 - Brookings	Tax Depreciation Expense	1,834,736	1,834,736	1,834,736	1,834,736	1,834,736	1,834,736	1,834,736	1,834,736	1,834,736	1,834,736	1,834,736	1,834,736	**22,016,828**
CAPX2020 - Brookings	CPI-TAX INTEREST													
CAPX2020 - Brookings	Debt Return	604,102	610,127	608,104	606,081	604,058	602,034	600,011	597,988	595,962	593,937	591,913	589,890	**7,204,208**
CAPX2020 - Brookings	Equity Return	1,278,012	1,290,758	1,286,478	1,282,198	1,277,917	1,273,637	1,269,357	1,265,077	1,260,791	1,256,506	1,252,226	1,247,945	**15,240,902**
CAPX2020 - Brookings	Current Income Tax Requirement	210,685	215,826	214,100	212,373	210,647	208,920	207,194	205,467	203,739	202,010	200,284	198,557	**2,489,801**
CAPX2020 - Brookings	Book Depreciation	783,529	783,529	783,529	783,529	783,529	783,529	783,529	783,529	783,529	783,529	783,529	783,529	**9,402,348**
CAPX2020 - Brookings	AFUDC													
CAPX2020 - Brookings	Deferred Taxes	295,530	295,530	295,530	295,530	295,530	295,530	295,530	295,530	295,530	295,530	295,530	295,530	**3,546,365**
CAPX2020 - Brookings	Property Tax Expense	583,384	583,384	583,384	583,384	583,384	583,384	583,384	583,384	583,384	583,384	583,384	583,384	**7,000,614**
CAPX2020 - Brookings	OATT Credit													
CAPX2020 - Brookings	Total Revenue Requirement	3,755,243	3,779,155	3,771,125	3,763,096	3,755,066	3,747,036	3,739,006	3,730,976	3,722,936	3,714,897	3,706,867	3,698,837	**44,884,238**
CAPX2020 - Brookings	**Rider Revenue Requirement**	2,751,523	2,769,044	2,763,160	2,757,276	2,751,393	2,745,509	2,739,625	2,733,742	2,727,851	2,721,960	2,716,077	2,710,193	**32,887,354**
CAPX2020 - Fargo	CWIP Balance	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	**(313)**
CAPX2020 - Fargo	Plant In-Service	208,060,400	208,176,482	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	**208,178,308**
CAPX2020 - Fargo	Depreciation Reserve	20,890,539	21,280,186	21,669,946	22,059,708	22,449,469	22,839,230	23,228,992	23,618,753	24,008,515	24,398,276	24,788,038	25,177,799	**25,177,799**
CAPX2020 - Fargo	Accumulated Deferred Taxes	45,529,537	45,690,518	45,851,499	46,012,480	46,173,462	46,334,443	46,495,424	46,656,405	46,817,387	46,978,368	47,139,349	47,300,331	**47,300,331**
CAPX2020 - Fargo	Average Rate Base	141,914,592	141,422,738	140,931,008	140,381,179	139,830,436	139,279,693	138,728,951	138,178,208	137,627,465	137,076,722	136,525,980	135,975,237	**135,975,237**
CAPX2020 - Fargo	Tax Depreciation Expense	964,462	964,462	964,462	964,462	964,462	964,462	964,462	964,462	964,462	964,462	964,462	964,462	**11,573,540**
CAPX2020 - Fargo	CPI-TAX INTEREST													
CAPX2020 - Fargo	Debt Return	266,090	265,168	264,246	263,215	262,182	261,149	260,117	259,084	258,051	257,019	255,986	254,954	**3,127,260**
CAPX2020 - Fargo	Equity Return	562,928	560,977	559,026	556,845	554,661	552,476	550,292	548,107	545,922	543,738	541,553	539,368	**6,615,893**
CAPX2020 - Fargo	Current Income Tax Requirement	60,092	59,351	58,609	57,730	56,849	55,968	55,087	54,206	53,324	52,443	51,562	50,681	**665,902**
CAPX2020 - Fargo	Book Depreciation	389,536	389,647	389,760	389,761	389,761	389,761	389,761	389,761	389,761	389,761	389,761	389,761	**4,676,796**
CAPX2020 - Fargo	AFUDC													
CAPX2020 - Fargo	Deferred Taxes	160,981	160,981	160,981	160,981	160,981	160,981	160,981	160,981	160,981	160,981	160,981	160,981	**1,931,775**
CAPX2020 - Fargo	Property Tax Expense	267,172	267,172	267,172	267,172	267,172	267,172	267,172	267,172	267,172	267,172	267,172	267,172	**3,206,063**
CAPX2020 - Fargo	OATT Credit													
CAPX2020 - Fargo	Total Revenue Requirement	1,706,799	1,703,296	1,699,794	1,695,705	1,691,607	1,687,508	1,683,410	1,679,311	1,675,213	1,671,114	1,667,016	1,662,918	**20,223,690**
CAPX2020 - Fargo	**Rider Revenue Requirement**	1,250,597	1,248,030	1,245,465	1,242,468	1,239,465	1,236,462	1,233,459	1,230,457	1,227,454	1,224,451	1,221,448	1,218,445	**14,818,201**
CAPX2020 - La Crosse Local	CWIP Balance	(1,739)	(1,853)	(1,975)	(2,063)	(2,215)	(2,245)	(2,279)	(2,362)	(2,437)	(2,437)	(2,606)	(2,437)	**(2,437)**
CAPX2020 - La Crosse Local	Plant In-Service	75,626,525	75,626,024	75,625,657	75,625,320	75,625,046	75,624,653	75,624,271	75,623,917	75,623,613	75,623,352	76,314,777	76,436,506	**76,436,506**
CAPX2020 - La Crosse Local	Depreciation Reserve	4,437,236	4,578,501	4,719,765	4,861,028	5,002,291	5,143,553	5,284,814	5,426,075	5,567,335	5,708,594	5,850,512	5,993,204	**5,993,204**
CAPX2020 - La Crosse Local	Accumulated Deferred Taxes	16,091,699	16,156,880	16,222,062	16,287,243	16,352,425	16,417,606	16,482,787	16,547,969	16,613,150	16,678,331	16,743,513	16,808,694	**16,808,694**
CAPX2020 - La Crosse Local	Average Rate Base	55,306,879	54,992,320	54,785,323	54,578,421	54,371,551	54,164,683	53,957,820	53,750,951	53,544,101	53,337,341	53,476,068	53,675,159	**53,675,159**
CAPX2020 - La Crosse Local	Tax Depreciation Expense	374,266	374,266	374,266	374,266	374,266	374,266	374,266	374,266	374,266	374,266	374,266	374,266	**4,491,191**
CAPX2020 - La Crosse Local	CPI-TAX INTEREST													
CAPX2020 - La Crosse Local	Debt Return	103,700	103,111	102,722	102,335	101,947	101,559	101,171	100,783	100,395	100,008	100,268	100,641	**1,218,639**
CAPX2020 - La Crosse Local	Equity Return	219,384	218,136	217,315	216,494	215,674	214,853	214,033	213,212	212,392	211,571	212,122	212,911	**2,578,098**
CAPX2020 - La Crosse Local	Current Income Tax Requirement	20,880	20,295	19,964	19,632	19,301	18,970	18,639	18,307	17,976	17,645	18,133	18,764	**228,506**
CAPX2020 - La Crosse Local	Book Depreciation	141,467	141,265	141,264	141,263	141,263	141,262	141,261	141,261	141,260	141,259	141,918	142,692	**1,697,435**
CAPX2020 - La Crosse Local	AFUDC													
CAPX2020 - La Crosse Local	Deferred Taxes	65,181	65,181	65,181	65,181	65,181	65,181	65,181	65,181	65,181	65,181	65,181	65,181	**782,176**
CAPX2020 - La Crosse Local	Property Tax Expense	97,386	97,386	97,386	97,386	97,386	97,386	97,386	97,386	97,386	97,386	97,386	97,386	**1,168,628**
CAPX2020 - La Crosse Local	OATT Credit	170,880	170,192	169,785	169,379	168,973	168,567	168,161	167,755	167,349	166,943	167,459	168,136	**2,023,581**
CAPX2020 - La Crosse Local	Total Revenue Requirement	477,118	475,182	474,047	472,912	471,778	470,644	469,509	468,375	467,241	466,107	467,548	469,439	**5,649,900**
CAPX2020 - La Crosse Local	**Rider Revenue Requirement**	349,592	348,173	347,341	346,510	345,679	344,848	344,017	343,185	342,354	341,524	342,579	343,965	**4,139,767**

Project	Rider Components	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
CAPX2020 - Brookings	CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - Brookings	Plant In-Service	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	**462,892,932**
CAPX2020 - Brookings	Depreciation Reserve	49,279,562	50,061,172	50,842,783	51,624,393	52,406,004	53,187,614	53,969,224	54,750,835	55,532,445	56,314,056	57,095,666	57,877,276	**57,877,276**
CAPX2020 - Brookings	Accumulated Deferred Taxes	100,452,708	100,578,963	100,640,055	100,768,346	100,892,565	101,020,857	101,145,076	101,271,331	101,399,623	101,523,841	101,652,133	101,776,352	**101,776,352**
CAPX2020 - Brookings	Average Rate Base	313,614,594	312,643,601	311,800,900	310,890,998	309,985,168	309,075,266	308,169,437	307,261,571	306,351,669	305,445,840	304,535,938	303,630,109	**303,630,109**
CAPX2020 - Brookings	Tax Depreciation Expense	1,230,485	1,230,485	1,230,485	1,230,485	1,230,485	1,230,485	1,230,485	1,230,485	1,230,485	1,230,485	1,230,485	1,230,485	**14,765,822**
CAPX2020 - Brookings	CPI-TAX INTEREST													
CAPX2020 - Brookings	Debt Return	588,027	586,207	584,627	582,921	581,222	579,516	577,818	576,115	574,409	572,711	571,005	569,306	**6,943,885**
CAPX2020 - Brookings	Equity Return	1,244,005	1,240,153	1,236,810	1,233,201	1,229,608	1,225,999	1,222,405	1,218,804	1,215,195	1,211,602	1,207,993	1,204,399	**14,690,174**
CAPX2020 - Brookings	Current Income Tax Requirement	371,642	370,088	368,740	367,284	365,835	364,379	362,930	361,477	360,021	358,572	357,116	355,667	**4,363,752**
CAPX2020 - Brookings	Book Depreciation	781,610	781,610	781,610	781,610	781,610	781,610	781,610	781,610	781,610	781,610	781,610	781,610	**9,379,325**
CAPX2020 - Brookings	AFUDC													
CAPX2020 - Brookings	Deferred Taxes	126,255	126,255	126,255	126,255	126,255	126,255	126,255	126,255	126,255	126,255	126,255	126,255	**1,515,063**
CAPX2020 - Brookings	Property Tax Expense	581,006	581,006	581,006	581,006	581,006	581,006	581,006	581,006	581,006	581,006	581,006	581,006	**6,972,067**
CAPX2020 - Brookings	OATT Credit													
CAPX2020 - Brookings	Total Revenue Requirement	3,692,545	3,685,319	3,679,048	3,672,277	3,665,536	3,658,765	3,652,024	3,645,268	3,638,497	3,631,756	3,624,985	3,618,244	**43,864,264**
CAPX2020 - Brookings	**Rider Revenue Requirement**	2,704,548	2,699,255	2,694,662	2,689,703	2,684,765	2,679,806	2,674,869	2,669,921	2,664,961	2,660,024	2,655,064	2,650,127	**32,127,705**
CAPX2020 - Fargo	CWIP Balance	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	(313)	**(313)**
CAPX2020 - Fargo	Plant In-Service	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	**208,178,308**
CAPX2020 - Fargo	Depreciation Reserve	25,566,609	25,955,419	26,344,228	26,733,038	27,121,848	27,510,657	27,899,467	28,288,277	28,677,086	29,065,896	29,454,706	29,843,516	**29,843,516**
CAPX2020 - Fargo	Accumulated Deferred Taxes	47,413,190	47,526,049	47,580,658	47,695,338	47,806,377	47,921,056	48,032,095	48,144,954	48,259,634	48,370,673	48,485,352	48,596,391	**48,596,391**
CAPX2020 - Fargo	Average Rate Base	135,449,031	134,890,933	134,447,514	133,944,024	133,444,176	132,940,687	132,440,838	131,939,169	131,435,680	130,935,831	130,432,342	129,932,494	**129,932,494**
CAPX2020 - Fargo	Tax Depreciation Expense	791,821	791,821	791,821	791,821	791,821	791,821	791,821	791,821	791,821	791,821	791,821	791,821	**9,501,850**
CAPX2020 - Fargo	CPI-TAX INTEREST													
CAPX2020 - Fargo	Debt Return	253,967	252,920	252,089	251,145	250,208	249,264	248,327	247,386	246,442	245,505	244,561	243,623	**2,985,436**
CAPX2020 - Fargo	Equity Return	537,281	535,067	533,308	531,311	529,329	527,331	525,349	523,359	521,362	519,379	517,382	515,399	**6,315,856**
CAPX2020 - Fargo	Current Income Tax Requirement	99,680	98,787	98,077	97,272	96,472	95,667	94,867	94,064	93,259	92,459	91,653	90,854	**1,143,111**
CAPX2020 - Fargo	Book Depreciation	388,810	388,810	388,810	388,810	388,810	388,810	388,810	388,810	388,810	388,810	388,810	388,810	**4,665,716**
CAPX2020 - Fargo	AFUDC													
CAPX2020 - Fargo	Deferred Taxes	112,859	112,859	112,859	112,859	112,859	112,859	112,859	112,859	112,859	112,859	112,859	112,859	**1,354,310**
CAPX2020 - Fargo	Property Tax Expense	261,297	261,297	261,297	261,297	261,297	261,297	261,297	261,297	261,297	261,297	261,297	261,297	**3,135,570**
CAPX2020 - Fargo	OATT Credit													
CAPX2020 - Fargo	Total Revenue Requirement	1,653,894	1,649,741	1,646,441	1,642,695	1,638,975	1,635,228	1,631,508	1,627,775	1,624,028	1,620,309	1,616,562	1,612,842	**19,600,000**
CAPX2020 - Fargo	**Rider Revenue Requirement**	1,211,369	1,208,328	1,205,911	1,203,166	1,200,442	1,197,698	1,194,973	1,192,239	1,189,495	1,186,770	1,184,026	1,181,302	**14,355,718**
CAPX2020 - La Crosse Local	CWIP Balance	(2,437)	(2,437)	(2,437)	(2,437)	(2,299)	(2,299)	(2,299)	(2,299)	(2,299)	(2,299)	(2,299)	(2,299)	**(2,299)**
CAPX2020 - La Crosse Local	Plant In-Service	76,436,363	76,436,212	76,436,094	76,436,042	76,437,553	76,474,501	76,474,501	76,474,501	76,474,501	76,474,501	76,474,501	76,474,501	**76,474,501**
CAPX2020 - La Crosse Local	Depreciation Reserve	6,135,658	6,278,112	6,420,566	6,563,019	6,705,474	6,847,965	6,990,491	7,133,017	7,275,543	7,418,070	7,560,596	7,703,122	**7,703,122**
CAPX2020 - La Crosse Local	Accumulated Deferred Taxes	16,862,436	16,916,178	16,942,183	16,996,792	17,049,667	17,104,276	17,157,152	17,210,894	17,265,503	17,318,378	17,372,987	17,425,863	**17,425,863**
CAPX2020 - La Crosse Local	Average Rate Base	53,534,002	53,310,787	53,142,194	52,945,047	52,750,516	52,572,732	52,395,822	52,199,554	52,002,419	51,807,017	51,609,882	51,414,480	**51,414,480**
CAPX2020 - La Crosse Local	Tax Depreciation Expense	334,404	334,404	334,404	334,404	334,404	334,404	334,404	334,404	334,404	334,404	334,404	334,404	**4,012,852**
CAPX2020 - La Crosse Local	CPI-TAX INTEREST													
CAPX2020 - La Crosse Local	Debt Return	100,376	99,958	99,642	99,272	98,907	98,574	98,242	97,874	97,505	97,138	96,769	96,402	**1,180,658**
CAPX2020 - La Crosse Local	Equity Return	212,352	211,466	210,797	210,015	209,244	208,539	207,837	207,058	206,276	205,501	204,719	203,944	**2,497,748**
CAPX2020 - La Crosse Local	Current Income Tax Requirement	29,906	29,549	29,279	28,963	28,653	28,383	28,114	27,800	27,484	27,172	26,856	26,544	**338,703**
CAPX2020 - La Crosse Local	Book Depreciation	142,454	142,454	142,454	142,453	142,455	142,491	142,526	142,526	142,526	142,526	142,526	142,526	**1,709,918**
CAPX2020 - La Crosse Local	AFUDC													
CAPX2020 - La Crosse Local	Deferred Taxes	53,742	53,742	53,742	53,742	53,742	53,742	53,742	53,742	53,742	53,742	53,742	53,742	**644,907**
CAPX2020 - La Crosse Local	Property Tax Expense	95,940	95,940	95,940	95,940	95,940	95,940	95,940	95,940	95,940	95,940	95,940	95,940	**1,151,282**
CAPX2020 - La Crosse Local	OATT Credit	155,998	155,590	155,282	154,921	154,564	154,250	153,939	153,580	153,219	152,862	152,501	152,144	**1,848,849**
CAPX2020 - La Crosse Local	Total Revenue Requirement	478,772	477,519	476,572	475,466	474,377	473,419	472,463	471,361	470,255	469,158	468,051	466,955	**5,674,367**
CAPX2020 - La Crosse Local	**Rider Revenue Requirement**	350,669	349,751	349,058	348,247	347,450	346,748	346,048	345,241	344,431	343,628	342,817	342,014	**4,156,103**

Project	Rider Components	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
CAPX2020 - Brookings	CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - Brookings	Plant In-Service	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	**462,892,932**
CAPX2020 - Brookings	Depreciation Reserve	58,657,722	59,438,167	60,218,612	60,999,058	61,779,503	62,559,948	63,340,394	64,120,839	64,901,284	65,681,730	66,462,175	67,242,620	**67,242,620**
CAPX2020 - Brookings	Accumulated Deferred Taxes	101,874,468	101,940,373	102,006,278	102,072,183	102,138,087	102,203,992	102,269,897	102,335,802	102,401,706	102,467,611	102,533,516	102,599,421	**102,599,421**
CAPX2020 - Brookings	Average Rate Base	302,750,965	301,904,614	301,058,264	300,211,914	299,365,564	298,519,214	297,672,864	296,826,514	295,980,164	295,133,814	294,287,464	293,441,113	**293,441,113**
CAPX2020 - Brookings	Tax Depreciation Expense	1,014,821	1,014,821	1,014,821	1,014,821	1,014,821	1,014,821	1,014,821	1,014,821	1,014,821	1,014,821	1,014,821	1,014,821	**12,177,855**
CAPX2020 - Brookings	CPI-TAX INTEREST													
CAPX2020 - Brookings	Debt Return	567,658	566,071	564,484	562,897	561,310	559,724	558,137	556,550	554,963	553,376	551,789	550,202	**6,707,161**
CAPX2020 - Brookings	Equity Return	1,200,912	1,197,555	1,194,198	1,190,841	1,187,483	1,184,126	1,180,769	1,177,412	1,174,055	1,170,697	1,167,340	1,163,983	**14,189,371**
CAPX2020 - Brookings	Current Income Tax Requirement	416,436	415,082	413,728	412,374	411,020	409,666	408,312	406,957	405,603	404,249	402,895	401,541	**4,907,864**
CAPX2020 - Brookings	Book Depreciation	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	**9,365,344**
CAPX2020 - Brookings	AFUDC													
CAPX2020 - Brookings	Deferred Taxes	65,905	65,905	65,905	65,905	65,905	65,905	65,905	65,905	65,905	65,905	65,905	65,905	**790,857**
CAPX2020 - Brookings	Property Tax Expense	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	**6,863,783**
CAPX2020 - Brookings	OATT Credit													
CAPX2020 - Brookings	Total Revenue Requirement	3,603,339	3,597,040	3,590,742	3,584,444	3,578,146	3,571,847	3,565,549	3,559,251	3,552,953	3,546,655	3,540,356	3,534,058	**42,824,380**
CAPX2020 - Brookings	**Rider Revenue Requirement**	2,633,680	2,629,077	2,624,473	2,619,870	2,615,266	2,610,663	2,606,060	2,601,456	2,596,853	2,592,250	2,587,646	2,583,043	**31,300,336**
CAPX2020 - Fargo	CWIP Balance	(313)	(313)	(313)	(313)	(313)	(313)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - Fargo	Plant In-Service	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,178,308	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	**208,177,995**
CAPX2020 - Fargo	Depreciation Reserve	30,231,756	30,619,997	31,008,237	31,396,477	31,784,718	32,172,958	32,561,199	32,949,439	33,337,678	33,725,918	34,114,158	34,502,398	**34,502,398**
CAPX2020 - Fargo	Accumulated Deferred Taxes	48,684,894	48,745,399	48,805,904	48,866,409	48,926,914	48,987,420	49,047,925	49,108,430	49,168,935	49,229,441	49,289,946	49,350,451	**49,350,451**
CAPX2020 - Fargo	Average Rate Base	129,455,466	129,006,720	128,557,975	128,109,229	127,660,483	127,211,737	126,762,992	126,314,247	125,865,502	125,416,756	124,968,011	124,519,266	**124,519,266**
CAPX2020 - Fargo	Tax Depreciation Expense	604,501	604,501	604,501	604,501	604,501	604,501	604,501	604,501	604,501	604,501	604,501	604,501	**7,254,017**
CAPX2020 - Fargo	CPI-TAX INTEREST													
CAPX2020 - Fargo	Debt Return	242,729	241,888	241,046	240,205	239,363	238,522	237,681	236,839	235,998	235,156	234,315	233,474	**2,857,216**
CAPX2020 - Fargo	Equity Return	513,507	511,727	509,947	508,167	506,387	504,607	502,827	501,047	499,266	497,486	495,706	493,926	**6,044,599**
CAPX2020 - Fargo	Current Income Tax Requirement	144,299	143,581	142,863	142,145	141,427	140,709	139,991	139,273	138,555	137,837	137,119	136,401	**1,684,204**
CAPX2020 - Fargo	Book Depreciation	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	**4,658,883**
CAPX2020 - Fargo	AFUDC													
CAPX2020 - Fargo	Deferred Taxes	60,505	60,505	60,505	60,505	60,505	60,505	60,505	60,505	60,505	60,505	60,505	60,505	**726,063**
CAPX2020 - Fargo	Property Tax Expense	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	**3,086,871**
CAPX2020 - Fargo	OATT Credit													
CAPX2020 - Fargo	Total Revenue Requirement	1,606,520	1,603,181	1,599,841	1,596,502	1,593,162	1,589,823	1,586,483	1,583,143	1,579,804	1,576,465	1,573,125	1,569,786	**19,057,834**
CAPX2020 - Fargo	**Rider Revenue Requirement**	1,174,205	1,171,765	1,169,324	1,166,883	1,164,442	1,162,001	1,159,560	1,157,119	1,154,679	1,152,238	1,149,797	1,147,356	**13,929,370**
CAPX2020 - La Crosse Local	CWIP Balance	(2,299)	(2,299)	(2,299)	(2,299)	(2,299)	(2,299)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - La Crosse Local	Plant In-Service	76,474,501	76,474,501	76,474,501	76,474,501	76,474,501	76,308,856	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	**76,306,557**
CAPX2020 - La Crosse Local	Depreciation Reserve	7,845,418	7,987,715	8,130,011	8,272,308	8,414,604	8,556,743	8,698,723	8,840,701	8,982,679	9,124,657	9,266,635	9,408,613	**9,408,613**
CAPX2020 - La Crosse Local	Accumulated Deferred Taxes	17,477,249	17,524,547	17,571,845	17,619,142	17,666,440	17,713,738	17,761,035	17,808,333	17,855,631	17,902,928	17,950,226	17,997,523	**17,997,523**
CAPX2020 - La Crosse Local	Average Rate Base	51,220,682	51,031,088	50,841,494	50,651,900	50,462,306	50,189,968	49,917,788	49,728,512	49,539,236	49,349,961	49,160,685	48,971,410	**48,971,410**
CAPX2020 - La Crosse Local	Tax Depreciation Expense	310,993	310,993	310,993	310,993	310,993	310,993	310,993	310,993	310,993	310,993	310,993	310,993	**3,731,918**
CAPX2020 - La Crosse Local	CPI-TAX INTEREST													
CAPX2020 - La Crosse Local	Debt Return	96,039	95,683	95,328	94,972	94,617	94,106	93,596	93,241	92,886	92,531	92,176	91,821	**1,126,997**
CAPX2020 - La Crosse Local	Equity Return	203,175	202,423	201,671	200,919	200,167	199,087	198,007	197,256	196,506	195,755	195,004	194,253	**2,384,225**
CAPX2020 - La Crosse Local	Current Income Tax Requirement	32,985	32,681	32,378	32,075	31,771	31,272	30,772	30,469	30,166	29,863	29,560	29,257	**373,249**
CAPX2020 - La Crosse Local	Book Depreciation	142,296	142,296	142,296	142,296	142,296	142,139	141,980	141,978	141,978	141,978	141,978	141,978	**1,705,491**
CAPX2020 - La Crosse Local	AFUDC													
CAPX2020 - La Crosse Local	Deferred Taxes	47,298	47,298	47,298	47,298	47,298	47,298	47,298	47,298	47,298	47,298	47,298	47,298	**567,572**
CAPX2020 - La Crosse Local	Property Tax Expense	94,497	94,497	94,497	94,497	94,497	94,497	94,497	94,497	94,497	94,497	94,497	94,497	**1,133,965**
CAPX2020 - La Crosse Local	OATT Credit	154,574	154,220	153,866	153,513	153,159	152,595	152,029	151,673	151,319	150,966	150,613	150,260	**1,828,786**
CAPX2020 - La Crosse Local	Total Revenue Requirement	461,716	460,659	459,602	458,545	457,488	455,804	454,121	453,066	452,011	450,955	449,900	448,845	**5,462,711**
CAPX2020 - La Crosse Local	**Rider Revenue Requirement**	337,468	336,695	335,923	335,150	334,378	333,147	331,917	331,146	330,375	329,603	328,832	328,061	**3,992,695**

Project	Rider Components	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
CAPX2020 - Brookings	CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - Brookings	Plant In-Service	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	**462,892,932**
CAPX2020 - Brookings	Depreciation Reserve	68,023,066	68,803,511	69,583,957	70,364,402	71,144,847	71,925,293	72,705,738	73,486,183	74,266,629	75,047,074	75,827,519	76,607,965	**76,607,965**
CAPX2020 - Brookings	Accumulated Deferred Taxes	102,665,338	102,731,268	102,797,198	102,863,128	102,929,058	102,994,988	103,059,854	103,125,784	103,192,777	103,257,644	103,324,637	103,389,504	**103,389,504**
CAPX2020 - Brookings	Average Rate Base	292,594,751	291,748,376	290,902,000	290,055,625	289,209,250	288,362,874	287,517,563	286,671,187	285,823,749	284,978,437	284,130,998	283,285,686	**283,285,686**
CAPX2020 - Brookings	Tax Depreciation Expense	1,014,861	1,014,861	1,014,861	1,014,861	1,014,861	1,014,861	1,014,861	1,014,861	1,014,861	1,014,861	1,014,861	1,014,861	**12,178,330**
CAPX2020 - Brookings	CPI-TAX INTEREST													
CAPX2020 - Brookings	Debt Return	548,615	547,028	545,441	543,854	542,267	540,680	539,095	537,508	535,920	534,335	532,746	531,161	**6,478,651**
CAPX2020 - Brookings	Equity Return	1,160,626	1,157,269	1,153,911	1,150,554	1,147,197	1,143,839	1,140,486	1,137,129	1,133,768	1,130,414	1,127,053	1,123,700	**13,705,946**
CAPX2020 - Brookings	Current Income Tax Requirement	400,181	398,827	397,473	396,118	394,764	393,410	392,058	390,704	389,348	387,995	386,639	385,287	**4,712,804**
CAPX2020 - Brookings	Book Depreciation	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	**9,365,344**
CAPX2020 - Brookings	AFUDC													
CAPX2020 - Brookings	Deferred Taxes	65,930	65,930	65,930	65,930	65,930	65,930	65,930	65,930	65,930	65,930	65,930	65,930	**791,159**
CAPX2020 - Brookings	Property Tax Expense	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	**6,863,783**
CAPX2020 - Brookings	OATT Credit													
CAPX2020 - Brookings	Total Revenue Requirement	3,527,779	3,521,481	3,515,182	3,508,884	3,502,585	3,496,287	3,489,997	3,483,698	3,477,392	3,471,101	3,464,795	3,458,505	**41,917,686**
CAPX2020 - Brookings	**Rider Revenue Requirement**	2,580,574	2,575,966	2,571,359	2,566,752	2,562,144	2,557,537	2,552,936	2,548,328	2,543,715	2,539,114	2,534,501	2,529,899	**30,662,824**
CAPX2020 - Fargo	CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - Fargo	Plant In-Service	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	**208,177,995**
CAPX2020 - Fargo	Depreciation Reserve	34,890,638	35,278,878	35,667,118	36,055,358	36,443,598	36,831,837	37,220,077	37,608,317	37,996,557	38,384,797	38,773,037	39,161,277	**39,161,277**
CAPX2020 - Fargo	Accumulated Deferred Taxes	49,410,873	49,471,213	49,531,553	49,591,893	49,652,232	49,712,572	49,771,938	49,832,278	49,893,591	49,952,957	50,014,270	50,073,637	**50,073,637**
CAPX2020 - Fargo	Average Rate Base	124,070,604	123,622,024	123,173,445	122,724,865	122,276,286	121,827,706	121,380,100	120,931,520	120,481,967	120,034,361	119,584,808	119,137,202	**119,137,202**
CAPX2020 - Fargo	Tax Depreciation Expense	603,913	603,913	603,913	603,913	603,913	603,913	603,913	603,913	603,913	603,913	603,913	603,913	**7,246,960**
CAPX2020 - Fargo	CPI-TAX INTEREST													
CAPX2020 - Fargo	Debt Return	232,632	231,791	230,950	230,109	229,268	228,427	227,588	226,747	225,904	225,064	224,222	223,382	**2,736,084**
CAPX2020 - Fargo	Equity Return	492,147	490,367	488,588	486,809	485,029	483,250	481,474	479,695	477,912	476,136	474,353	472,578	**5,788,338**
CAPX2020 - Fargo	Current Income Tax Requirement	135,854	135,136	134,419	133,701	132,983	132,265	131,549	130,832	130,112	129,396	128,677	127,961	**1,582,884**
CAPX2020 - Fargo	Book Depreciation	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	**4,658,879**
CAPX2020 - Fargo	AFUDC													
CAPX2020 - Fargo	Deferred Taxes	60,340	60,340	60,340	60,340	60,340	60,340	60,340	60,340	60,340	60,340	60,340	60,340	**724,076**
CAPX2020 - Fargo	Property Tax Expense	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	**3,086,866**
CAPX2020 - Fargo	OATT Credit													
CAPX2020 - Fargo	Total Revenue Requirement	1,566,451	1,563,113	1,559,775	1,556,437	1,553,099	1,549,761	1,546,430	1,543,092	1,539,746	1,536,415	1,533,070	1,529,739	**18,577,128**
CAPX2020 - Fargo	**Rider Revenue Requirement**	1,145,861	1,143,419	1,140,977	1,138,535	1,136,093	1,133,651	1,131,215	1,128,773	1,126,326	1,123,889	1,121,442	1,119,005	**13,589,185**
CAPX2020 - La Crosse Local	CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - La Crosse Local	Plant In-Service	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	**76,306,557**
CAPX2020 - La Crosse Local	Depreciation Reserve	9,550,590	9,692,568	9,834,546	9,976,524	10,118,502	10,260,480	10,402,457	10,544,435	10,686,413	10,828,391	10,970,369	11,112,347	**11,112,347**
CAPX2020 - La Crosse Local	Accumulated Deferred Taxes	18,027,542	18,040,283	18,053,023	18,065,764	18,078,504	18,091,244	18,103,779	18,116,520	18,129,466	18,142,000	18,154,946	18,167,481	**18,167,481**
CAPX2020 - La Crosse Local	Average Rate Base	48,799,413	48,644,695	48,489,976	48,335,258	48,180,540	48,025,822	47,871,309	47,716,591	47,561,667	47,407,154	47,252,231	47,097,718	**47,097,718**
CAPX2020 - La Crosse Local	Tax Depreciation Expense	187,702	187,702	187,702	187,702	187,702	187,702	187,702	187,702	187,702	187,702	187,702	187,702	**2,252,419**
CAPX2020 - La Crosse Local	CPI-TAX INTEREST													
CAPX2020 - La Crosse Local	Debt Return	91,499	91,209	90,919	90,629	90,339	90,048	89,759	89,469	89,178	88,888	88,598	88,308	**1,078,842**
CAPX2020 - La Crosse Local	Equity Return	193,571	192,957	192,344	191,730	191,116	190,502	189,890	189,276	188,661	188,048	187,434	186,821	**2,282,350**
CAPX2020 - La Crosse Local	Current Income Tax Requirement	64,773	64,526	64,278	64,031	63,783	63,535	63,288	63,041	62,793	62,546	62,298	62,051	**760,942**
CAPX2020 - La Crosse Local	Book Depreciation	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	**1,703,734**
CAPX2020 - La Crosse Local	AFUDC													
CAPX2020 - La Crosse Local	Deferred Taxes	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	12,740	**152,885**
CAPX2020 - La Crosse Local	Property Tax Expense	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	**1,131,475**
CAPX2020 - La Crosse Local	OATT Credit	143,211	142,936	142,660	142,385	142,110	141,834	141,559	141,284	141,008	140,733	140,458	140,183	**1,700,361**
CAPX2020 - La Crosse Local	Total Revenue Requirement	455,640	454,764	453,888	453,012	452,136	451,260	450,385	449,509	448,632	447,757	446,880	446,005	**5,409,866**
CAPX2020 - La Crosse Local	**Rider Revenue Requirement**	333,301	332,660	332,019	331,379	330,738	330,097	329,457	328,816	328,175	327,535	326,893	326,253	**3,957,322**

Project	Rider Components	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
CAPX2020 - Brookings	CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - Brookings	Plant In-Service	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	462,892,932	**462,892,932**
CAPX2020 - Brookings	Depreciation Reserve	77,388,410	78,168,855	78,949,301	79,729,746	80,510,191	81,290,637	82,071,082	82,851,527	83,631,973	84,412,418	85,192,863	85,973,309	**85,973,309**
CAPX2020 - Brookings	Accumulated Deferred Taxes	103,455,240	103,521,828	103,586,301	103,652,888	103,717,362	103,783,949	103,848,422	103,913,953	103,980,540	104,045,013	104,111,601	104,176,074	**104,176,074**
CAPX2020 - Brookings	Average Rate Base	282,439,504	281,592,472	280,747,553	279,900,520	279,055,602	278,208,569	277,363,650	276,517,674	275,670,642	274,825,723	273,978,690	273,133,772	**273,133,772**
CAPX2020 - Brookings	Tax Depreciation Expense	1,013,452	1,013,452	1,013,452	1,013,452	1,013,452	1,013,452	1,013,452	1,013,452	1,013,452	1,013,452	1,013,452	1,013,452	**12,161,429**
CAPX2020 - Brookings	CPI-TAX INTEREST													
CAPX2020 - Brookings	Debt Return	529,574	527,986	526,402	524,813	523,229	521,641	520,057	518,471	516,882	515,298	513,710	512,126	**6,250,189**
CAPX2020 - Brookings	Equity Return	1,120,343	1,116,983	1,113,632	1,110,272	1,106,921	1,103,561	1,100,209	1,096,853	1,093,494	1,090,142	1,086,782	1,083,431	**13,222,623**
CAPX2020 - Brookings	Current Income Tax Requirement	384,340	382,985	381,633	380,278	378,926	377,571	376,219	374,865	373,510	372,158	370,803	369,451	**4,522,738**
CAPX2020 - Brookings	Book Depreciation	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	780,445	**9,365,344**
CAPX2020 - Brookings	AFUDC													
CAPX2020 - Brookings	Deferred Taxes	65,530	65,530	65,530	65,530	65,530	65,530	65,530	65,530	65,530	65,530	65,530	65,530	**786,364**
CAPX2020 - Brookings	Property Tax Expense	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	571,982	**6,863,783**
CAPX2020 - Brookings	OATT Credit													
CAPX2020 - Brookings	Total Revenue Requirement	3,452,215	3,445,912	3,439,624	3,433,321	3,427,033	3,420,730	3,414,442	3,408,147	3,401,844	3,395,556	3,389,253	3,382,965	**41,011,041**
CAPX2020 - Brookings	**Rider Revenue Requirement**	2,521,086	2,516,483	2,511,891	2,507,288	2,502,696	2,498,093	2,493,501	2,488,904	2,484,301	2,479,709	2,475,106	2,470,514	**29,949,570**
CAPX2020 - Fargo	CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - Fargo	Plant In-Service	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	208,177,995	**208,177,995**
CAPX2020 - Fargo	Depreciation Reserve	39,549,517	39,937,757	40,325,996	40,714,236	41,102,476	41,490,716	41,878,956	42,267,196	42,655,436	43,043,676	43,431,916	43,820,155	**43,820,155**
CAPX2020 - Fargo	Accumulated Deferred Taxes	50,133,890	50,195,020	50,254,209	50,315,339	50,374,528	50,435,659	50,494,848	50,555,008	50,616,138	50,675,327	50,736,457	50,795,647	**50,795,647**
CAPX2020 - Fargo	Average Rate Base	118,688,709	118,239,339	117,791,910	117,342,540	116,895,111	116,445,741	115,998,311	115,549,912	115,100,542	114,653,112	114,203,743	113,756,313	**113,756,313**
CAPX2020 - Fargo	Tax Depreciation Expense	603,274	603,274	603,274	603,274	603,274	603,274	603,274	603,274	603,274	603,274	603,274	603,274	**7,239,283**
CAPX2020 - Fargo	CPI-TAX INTEREST													
CAPX2020 - Fargo	Debt Return	222,541	221,699	220,860	220,017	219,178	218,336	217,497	216,656	215,814	214,975	214,132	213,293	**2,614,997**
CAPX2020 - Fargo	Equity Return	470,799	469,016	467,241	465,459	463,684	461,901	460,127	458,348	456,565	454,791	453,008	451,233	**5,532,172**
CAPX2020 - Fargo	Current Income Tax Requirement	127,429	126,710	125,994	125,275	124,559	123,840	123,124	122,407	121,688	120,972	120,253	119,537	**1,481,785**
CAPX2020 - Fargo	Book Depreciation	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	388,240	**4,658,879**
CAPX2020 - Fargo	AFUDC													
CAPX2020 - Fargo	Deferred Taxes	60,160	60,160	60,160	60,160	60,160	60,160	60,160	60,160	60,160	60,160	60,160	60,160	**721,917**
CAPX2020 - Fargo	Property Tax Expense	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	257,239	**3,086,866**
CAPX2020 - Fargo	OATT Credit													
CAPX2020 - Fargo	Total Revenue Requirement	1,526,407	1,523,063	1,519,733	1,516,389	1,513,060	1,509,716	1,506,386	1,503,049	1,499,705	1,496,376	1,493,031	1,489,702	**18,096,616**
CAPX2020 - Fargo	**Rider Revenue Requirement**	1,114,705	1,112,263	1,109,832	1,107,390	1,104,958	1,102,516	1,100,085	1,097,648	1,095,206	1,092,774	1,090,332	1,087,900	**13,215,609**
CAPX2020 - La Crosse Local	CWIP Balance	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	(0)	**(0)**
CAPX2020 - La Crosse Local	Plant In-Service	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	76,306,557	**76,306,557**
CAPX2020 - La Crosse Local	Depreciation Reserve	11,254,324	11,396,302	11,538,280	11,680,258	11,822,236	11,964,214	12,106,191	12,248,169	12,390,147	12,532,125	12,674,103	12,816,081	**12,816,081**
CAPX2020 - La Crosse Local	Accumulated Deferred Taxes	18,180,342	18,193,540	18,206,320	18,219,518	18,232,298	18,245,496	18,258,275	18,271,264	18,284,463	18,297,242	18,310,441	18,323,220	**18,323,220**
CAPX2020 - La Crosse Local	Average Rate Base	46,942,880	46,787,703	46,632,946	46,477,770	46,323,012	46,167,836	46,013,079	45,858,112	45,702,936	45,548,179	45,393,002	45,238,245	**45,238,245**
CAPX2020 - La Crosse Local	Tax Depreciation Expense	188,594	188,594	188,594	188,594	188,594	188,594	188,594	188,594	188,594	188,594	188,594	188,594	**2,263,129**
CAPX2020 - La Crosse Local	CPI-TAX INTEREST													
CAPX2020 - La Crosse Local	Debt Return	88,018	87,727	87,437	87,146	86,856	86,565	86,275	85,984	85,693	85,403	85,112	84,822	**1,037,036**
CAPX2020 - La Crosse Local	Equity Return	186,207	185,591	184,977	184,362	183,748	183,132	182,519	181,904	181,288	180,674	180,059	179,445	**2,193,907**
CAPX2020 - La Crosse Local	Current Income Tax Requirement	61,543	61,295	61,047	60,799	60,551	60,303	60,055	59,808	59,559	59,312	59,063	58,816	**722,151**
CAPX2020 - La Crosse Local	Book Depreciation	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	141,978	**1,703,734**
CAPX2020 - La Crosse Local	AFUDC													
CAPX2020 - La Crosse Local	Deferred Taxes	12,989	12,989	12,989	12,989	12,989	12,989	12,989	12,989	12,989	12,989	12,989	12,989	**155,867**
CAPX2020 - La Crosse Local	Property Tax Expense	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	94,290	**1,131,475**
CAPX2020 - La Crosse Local	OATT Credit	139,904	139,628	139,353	139,077	138,801	138,525	138,250	137,974	137,698	137,422	137,146	136,871	**1,660,650**
CAPX2020 - La Crosse Local	Total Revenue Requirement	445,120	444,241	443,365	442,486	441,610	440,731	439,855	438,978	438,099	437,223	436,344	435,468	**5,283,520**
CAPX2020 - La Crosse Local	**Rider Revenue Requirement**	325,062	324,421	323,781	323,139	322,499	321,858	321,218	320,577	319,935	319,295	318,654	318,014	**3,858,452**

Project	Rider Components	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
CAPX2020 - La Crosse MISO	CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CAPX2020 - La Crosse MISO	Plant In-Service	75,046,803	75,046,803	75,046,803	75,046,803	75,046,803	75,046,803	75,046,803	75,046,803	75,046,803	75,046,803	75,046,803	75,185,211	**75,185,211**
CAPX2020 - La Crosse MISO	Depreciation Reserve	5,569,928	5,697,633	5,825,339	5,953,044	6,080,750	6,208,455	6,336,161	6,463,866	6,591,571	6,719,277	6,846,982	6,974,820	**6,974,820**
CAPX2020 - La Crosse MISO	Accumulated Deferred Taxes	15,934,240	15,988,688	16,043,137	16,097,585	16,152,033	16,206,481	16,260,929	16,315,377	16,369,825	16,424,274	16,478,722	16,533,170	**16,533,170**
CAPX2020 - La Crosse MISO	Average Rate Base	53,651,180	53,451,558	53,269,405	53,087,251	52,905,097	52,722,944	52,540,790	52,358,637	52,176,483	51,994,329	51,812,176	51,699,160	**51,699,160**
CAPX2020 - La Crosse MISO	Tax Depreciation Expense	322,167	322,167	322,167	322,167	322,167	322,167	322,167	322,167	322,167	322,167	322,167	322,167	**3,865,998**
CAPX2020 - La Crosse MISO	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO	Debt Return	100,596	100,222	99,880	99,539	99,197	98,856	98,514	98,172	97,831	97,489	97,148	96,936	**1,184,379**
CAPX2020 - La Crosse MISO	Equity Return	212,816	212,025	211,302	210,579	209,857	209,134	208,412	207,689	206,967	206,244	205,522	205,073	**2,505,620**
CAPX2020 - La Crosse MISO	Current Income Tax Requirement	29,366	29,046	28,755	28,463	28,172	27,880	27,589	27,297	27,006	26,714	26,423	26,295	**333,006**
CAPX2020 - La Crosse MISO	Book Depreciation	127,706	127,705	127,705	127,705	127,705	127,705	127,705	127,705	127,705	127,705	127,705	127,837	**1,532,598**
CAPX2020 - La Crosse MISO	AFUDC													
CAPX2020 - La Crosse MISO	Deferred Taxes	54,448	54,448	54,448	54,448	54,448	54,448	54,448	54,448	54,448	54,448	54,448	54,448	**653,378**
CAPX2020 - La Crosse MISO	Property Tax Expense	96,414	96,414	96,414	96,414	96,414	96,414	96,414	96,414	96,414	96,414	96,414	96,414	**1,156,964**
CAPX2020 - La Crosse MISO	OATT Credit													
CAPX2020 - La Crosse MISO	Total Revenue Requirement	621,346	619,859	618,504	617,148	615,793	614,437	613,082	611,726	610,371	609,015	607,660	607,004	**7,365,946**
CAPX2020 - La Crosse MISO	**Rider Revenue Requirement**	455,270	454,180	453,187	452,194	451,201	450,207	449,214	448,221	447,228	446,235	445,241	444,761	**5,397,139**
CAPX2020 - La Crosse MISO - WI	CWIP Balance	(190)	23,370	42,160	43,243	(830)	(648)	(2,576)	(3,251)	(3,568)	(3,498)	(4,572)	(5,037)	**(5,037)**
CAPX2020 - La Crosse MISO - WI	Plant In-Service	135,741,472	135,742,387	135,744,962	135,747,261	135,802,336	135,936,897	136,121,963	136,164,102	136,139,595	136,141,033	136,147,870	136,087,284	**136,087,284**
CAPX2020 - La Crosse MISO - WI	Depreciation Reserve	11,725,527	12,020,623	12,315,724	12,610,830	12,905,939	13,201,166	13,496,621	13,792,240	14,087,879	14,383,486	14,679,087	14,974,606	**14,974,606**
CAPX2020 - La Crosse MISO - WI	Accumulated Deferred Taxes	31,460,929	31,551,144	31,641,358	31,731,573	31,821,788	31,912,002	32,002,217	32,092,432	32,182,646	32,272,861	32,363,076	32,453,291	**32,453,291**
CAPX2020 - La Crosse MISO - WI	Average Rate Base	92,745,326	92,374,408	92,012,015	91,639,070	91,260,940	90,948,430	90,721,815	90,448,364	90,070,840	89,673,345	89,291,162	88,877,743	**88,877,743**
CAPX2020 - La Crosse MISO - WI	Tax Depreciation Expense	617,530	617,530	617,530	617,530	617,530	617,530	617,530	617,530	617,530	617,530	617,530	617,530	**7,410,361**
CAPX2020 - La Crosse MISO - WI	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO - WI	Debt Return	173,897	173,202	172,523	171,823	171,114	170,528	170,103	169,591	168,883	168,138	167,421	166,646	**2,043,869**
CAPX2020 - La Crosse MISO - WI	Equity Return	367,890	366,418	364,981	363,502	362,002	360,762	359,863	358,779	357,281	355,704	354,188	352,548	**4,323,918**
CAPX2020 - La Crosse MISO - WI	Current Income Tax Requirement	54,720	54,129	53,551	52,957	52,353	51,900	51,630	51,259	50,663	50,014	49,400	48,706	**621,283**
CAPX2020 - La Crosse MISO - WI	Book Depreciation	295,090	295,096	295,100	295,106	295,109	295,226	295,455	295,619	295,639	295,607	295,601	295,520	**3,544,169**
CAPX2020 - La Crosse MISO - WI	AFUDC													
CAPX2020 - La Crosse MISO - WI	Deferred Taxes	90,215	90,215	90,215	90,215	90,215	90,215	90,215	90,215	90,215	90,215	90,215	90,215	**1,082,576**
CAPX2020 - La Crosse MISO - WI	Property Tax Expense	174,302	174,302	174,302	174,302	174,302	174,302	174,302	174,302	174,302	174,302	174,302	174,302	**2,091,624**
CAPX2020 - La Crosse MISO - WI	OATT Credit													
CAPX2020 - La Crosse MISO - WI	Total Revenue Requirement	1,156,114	1,153,363	1,150,672	1,147,905	1,145,095	1,142,934	1,141,569	1,139,764	1,136,982	1,133,979	1,131,127	1,127,936	**13,707,440**
CAPX2020 - La Crosse MISO - WI	**Rider Revenue Requirement**	847,102	845,086	843,115	841,087	839,028	837,445	836,444	835,122	833,084	830,883	828,793	826,456	**10,043,647**
Huntley - Wilmarth	CWIP Balance	2,576,287	2,877,512	2,680,557	2,844,982	2,902,143	2,968,614	3,085,614	3,176,373	3,263,988	3,180,003	3,400,167	3,468,561	**3,468,561**
Huntley - Wilmarth	Plant In-Service										252,026	395,047	705,622	**705,622**
Huntley - Wilmarth	Depreciation Reserve													
Huntley - Wilmarth	Accumulated Deferred Taxes	(10,027)	(10,259)	(10,492)	(10,724)	(10,956)	(11,188)	(11,421)	(11,653)	(11,885)	(12,117)	(12,350)	(12,582)	**(12,582)**
Huntley - Wilmarth	Average Rate Base	2,196,517	2,737,043	2,789,410	2,773,377	2,884,403	2,946,451	3,038,419	3,142,531	3,231,950	3,360,010	3,625,856	3,997,165	**3,997,165**
Huntley - Wilmarth	Tax Depreciation Expense													
Huntley - Wilmarth	CPI-TAX INTEREST	6,310	7,127	(80,286)	7,468	7,915	8,098	7,824	8,049	8,424	8,969	9,699	10,355	**9,953**
Huntley - Wilmarth	Debt Return	4,118	5,132	5,230	5,200	5,408	5,525	5,697	5,892	6,060	6,300	6,798	7,495	**68,856**
Huntley - Wilmarth	Equity Return	8,713	10,857	11,065	11,001	11,441	11,688	12,052	12,465	12,820	13,328	14,383	15,855	**145,668**
Huntley - Wilmarth	Current Income Tax Requirement	5,966	7,160	(28,014)	7,356	7,714	7,887	7,924	8,181	8,475	8,900	9,620	10,478	**61,646**
Huntley - Wilmarth	Book Depreciation													
Huntley - Wilmarth	AFUDC													
Huntley - Wilmarth	Deferred Taxes	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	(232)	**(2,787)**
Huntley - Wilmarth	Property Tax Expense													
Huntley - Wilmarth	OATT Credit													
Huntley - Wilmarth	Total Revenue Requirement	18,565	22,917	(11,952)	23,325	24,331	24,867	25,441	26,306	27,123	28,295	30,569	33,596	**273,383**
Huntley - Wilmarth	**Rider Revenue Requirement**	13,603	16,792	(8,757)	17,090	17,828	18,220	18,641	19,275	19,873	20,733	22,398	24,617	**200,312**

Project	Rider Components	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
CAPX2020 - La Crosse MISO	CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CAPX2020 - La Crosse MISO	Plant In-Service	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	**75,185,211**
CAPX2020 - La Crosse MISO	Depreciation Reserve	7,102,479	7,230,138	7,357,797	7,485,457	7,613,116	7,740,775	7,868,434	7,996,094	8,123,753	8,251,412	8,379,071	8,506,731	**8,506,731**
CAPX2020 - La Crosse MISO	Accumulated Deferred Taxes	16,570,380	16,607,591	16,625,596	16,663,407	16,700,017	16,737,828	16,774,438	16,811,649	16,849,460	16,886,070	16,923,881	16,960,491	**16,960,491**
CAPX2020 - La Crosse MISO	Average Rate Base	51,594,787	51,411,312	51,265,647	51,100,177	50,935,908	50,770,438	50,606,168	50,441,298	50,275,828	50,111,559	49,946,088	49,781,819	**49,781,819**
CAPX2020 - La Crosse MISO	Tax Depreciation Expense	260,402	260,402	260,402	260,402	260,402	260,402	260,402	260,402	260,402	260,402	260,402	260,402	**3,124,830**
CAPX2020 - La Crosse MISO	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO	Debt Return	96,740	96,396	96,123	95,813	95,505	95,195	94,887	94,577	94,267	93,959	93,649	93,341	**1,140,452**
CAPX2020 - La Crosse MISO	Equity Return	204,659	203,932	203,354	202,697	202,046	201,389	200,738	200,084	199,427	198,776	198,119	197,468	**2,412,689**
CAPX2020 - La Crosse MISO	Current Income Tax Requirement	44,016	43,723	43,490	43,225	42,962	42,697	42,435	42,171	41,906	41,643	41,379	41,116	**510,763**
CAPX2020 - La Crosse MISO	Book Depreciation	127,659	127,659	127,659	127,659	127,659	127,659	127,659	127,659	127,659	127,659	127,659	127,659	**1,531,911**
CAPX2020 - La Crosse MISO	AFUDC													
CAPX2020 - La Crosse MISO	Deferred Taxes	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	37,211	**446,527**
CAPX2020 - La Crosse MISO	Property Tax Expense	94,370	94,370	94,370	94,370	94,370	94,370	94,370	94,370	94,370	94,370	94,370	94,370	**1,132,435**
CAPX2020 - La Crosse MISO	OATT Credit													
CAPX2020 - La Crosse MISO	Total Revenue Requirement	604,655	603,290	602,206	600,975	599,752	598,521	597,298	596,072	594,840	593,618	592,386	591,164	**7,174,777**
CAPX2020 - La Crosse MISO	**Rider Revenue Requirement**	442,871	441,870	441,077	440,175	439,279	438,377	437,482	436,583	435,682	434,786	433,884	432,989	**5,255,055**
CAPX2020 - La Crosse MISO - WI	CWIP Balance	(5,275)	(6,419)	(6,427)	(7,157)	(4,561)	(4,666)	(6,749)	(6,749)	(6,749)	(6,781)	(6,781)	(6,781)	**(6,781)**
CAPX2020 - La Crosse MISO - WI	Plant In-Service	136,244,848	136,250,567	136,254,841	136,256,927	136,262,290	136,279,446	136,297,683	136,315,498	136,329,533	136,338,986	136,349,779	136,353,061	**136,353,061**
CAPX2020 - La Crosse MISO - WI	Depreciation Reserve	15,270,331	15,566,247	15,862,168	16,158,084	16,453,993	16,749,903	17,045,812	17,341,722	17,637,631	17,933,541	18,229,450	18,525,359	**18,525,359**
CAPX2020 - La Crosse MISO - WI	Accumulated Deferred Taxes	32,532,538	32,611,786	32,650,132	32,730,658	32,808,627	32,889,154	32,967,123	33,046,371	33,126,897	33,204,867	33,285,393	33,363,362	**33,363,362**
CAPX2020 - La Crosse MISO - WI	Average Rate Base	88,545,527	88,211,785	87,881,942	87,508,308	87,139,084	86,775,153	86,417,877	86,059,704	85,699,193	85,337,042	84,970,713	84,603,871	**84,603,871**
CAPX2020 - La Crosse MISO - WI	Tax Depreciation Expense	578,614	578,614	578,614	578,614	578,614	578,614	578,614	578,614	578,614	578,614	578,614	578,614	**6,943,369**
CAPX2020 - La Crosse MISO - WI	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO - WI	Debt Return	166,023	165,397	164,779	164,078	163,386	162,703	162,034	161,362	160,686	160,007	159,320	158,632	**1,948,407**
CAPX2020 - La Crosse MISO - WI	Equity Return	351,231	349,907	348,598	347,116	345,652	344,208	342,791	341,370	339,940	338,504	337,050	335,595	**4,121,962**
CAPX2020 - La Crosse MISO - WI	Current Income Tax Requirement	59,530	59,073	58,548	57,948	57,354	56,772	56,201	55,628	55,051	54,471	53,885	53,298	**677,759**
CAPX2020 - La Crosse MISO - WI	Book Depreciation	295,724	295,916	295,922	295,915	295,909	295,909	295,909	295,909	295,909	295,909	295,909	295,909	**3,550,753**
CAPX2020 - La Crosse MISO - WI	AFUDC													
CAPX2020 - La Crosse MISO - WI	Deferred Taxes	79,248	79,248	79,248	79,248	79,248	79,248	79,248	79,248	79,248	79,248	79,248	79,248	**950,974**
CAPX2020 - La Crosse MISO - WI	Property Tax Expense	170,812	170,812	170,812	170,812	170,812	170,812	170,812	170,812	170,812	170,812	170,812	170,812	**2,049,739**
CAPX2020 - La Crosse MISO - WI	OATT Credit													
CAPX2020 - La Crosse MISO - WI	Total Revenue Requirement	1,122,567	1,120,353	1,117,906	1,115,117	1,112,361	1,109,653	1,106,994	1,104,328	1,101,646	1,098,951	1,096,225	1,093,495	**13,299,594**
CAPX2020 - La Crosse MISO - WI	**Rider Revenue Requirement**	822,207	820,585	818,793	816,750	814,732	812,748	810,801	808,848	806,883	804,910	802,913	800,913	**9,741,083**
Huntley - Wilmarth	CWIP Balance	3,528,594	3,568,933	3,684,272	2,422,848	4,198,938	9,733,998	14,654,560	20,471,989	23,714,041	26,630,779	29,103,214	31,025,003	**31,025,003**
Huntley - Wilmarth	Plant In-Service	1,387,893	1,562,107	2,022,021	3,605,723	3,699,441	3,778,824	3,835,984	3,884,637	3,885,650	3,889,658	3,891,044	3,899,415	**3,899,415**
Huntley - Wilmarth	Depreciation Reserve				1,269	3,806	6,343	8,881	11,418	13,955	16,493	19,030	21,568	**21,568**
Huntley - Wilmarth	Accumulated Deferred Taxes	(26,348)	(40,115)	(46,776)	(60,765)	(74,309)	(88,298)	(101,842)	(115,608)	(129,597)	(143,141)	(157,130)	(170,674)	**(170,674)**
Huntley - Wilmarth	Average Rate Base	4,564,800	5,063,878	5,465,442	5,927,562	7,035,247	10,788,824	16,095,913	21,529,044	26,095,069	29,187,981	31,896,716	34,109,714	**34,109,714**
Huntley - Wilmarth	Tax Depreciation Expense	4,966	4,966	4,966	4,966	4,966	4,966	4,966	4,966	4,966	4,966	4,966	4,966	**59,591**
Huntley - Wilmarth	CPI-TAX INTEREST	10,754	10,875	12,274	12,961	16,758	30,591	47,794	70,312	87,543	99,638	110,289	119,054	**628,844**
Huntley - Wilmarth	Debt Return	8,559	9,495	10,248	11,114	13,191	20,229	30,180	40,367	48,928	54,727	59,806	63,956	**370,800**
Huntley - Wilmarth	Equity Return	18,107	20,087	21,680	23,513	27,906	42,796	63,847	85,399	103,510	115,779	126,524	135,302	**784,449**
Huntley - Wilmarth	Current Income Tax Requirement	4,085	4,933	6,139	7,668	11,483	23,068	38,498	56,274	70,529	80,357	88,987	96,063	**488,084**
Huntley - Wilmarth	Book Depreciation				1,269	2,537	2,537	2,537	2,537	2,537	2,537	2,537	2,537	**21,568**
Huntley - Wilmarth	AFUDC													
Huntley - Wilmarth	Deferred Taxes	(13,766)	(13,766)	(13,766)	(13,766)	(13,766)	(13,766)	(13,766)	(13,766)	(13,766)	(13,766)	(13,766)	(13,766)	**(165,198)**
Huntley - Wilmarth	Property Tax Expense	886	886	886	886	886	886	886	886	886	886	886	886	**10,628**
Huntley - Wilmarth	OATT Credit													
Huntley - Wilmarth	Total Revenue Requirement	17,871	21,633	25,186	30,682	42,237	75,750	122,182	171,696	212,624	240,520	264,973	284,977	**1,510,331**
Huntley - Wilmarth	**Rider Revenue Requirement**	13,089	15,845	18,447	22,473	30,936	55,482	89,490	125,756	155,733	176,165	194,075	208,727	**1,106,219**

Project	Rider Components	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
CAPX2020 - La Crosse MISO	CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CAPX2020 - La Crosse MISO	Plant In-Service	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	**75,185,211**
CAPX2020 - La Crosse MISO	Depreciation Reserve	8,634,213	8,761,696	8,889,179	9,016,661	9,144,144	9,271,627	9,399,110	9,526,592	9,654,075	9,781,558	9,909,040	10,036,523	**10,036,523**
CAPX2020 - La Crosse MISO	Accumulated Deferred Taxes	16,984,850	16,995,157	17,005,463	17,015,770	17,026,076	17,036,383	17,046,689	17,056,996	17,067,302	17,077,609	17,087,915	17,098,222	**17,098,222**
CAPX2020 - La Crosse MISO	Average Rate Base	49,629,889	49,492,100	49,354,311	49,216,522	49,078,732	48,940,943	48,803,154	48,665,365	48,527,576	48,389,786	48,251,997	48,114,208	**48,114,208**
CAPX2020 - La Crosse MISO	Tax Depreciation Expense	164,250	164,250	164,250	164,250	164,250	164,250	164,250	164,250	164,250	164,250	164,250	164,250	**1,970,996**
CAPX2020 - La Crosse MISO	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO	Debt Return	93,056	92,798	92,539	92,281	92,023	91,764	91,506	91,248	90,989	90,731	90,472	90,214	**1,099,621**
CAPX2020 - La Crosse MISO	Equity Return	196,865	196,319	195,772	195,226	194,679	194,132	193,586	193,039	192,493	191,946	191,400	190,853	**2,326,310**
CAPX2020 - La Crosse MISO	Current Income Tax Requirement	68,733	68,513	68,292	68,072	67,851	67,631	67,410	67,190	66,969	66,749	66,528	66,308	**810,246**
CAPX2020 - La Crosse MISO	Book Depreciation	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	**1,529,792**
CAPX2020 - La Crosse MISO	AFUDC													
CAPX2020 - La Crosse MISO	Deferred Taxes	10,307	10,307	10,307	10,307	10,307	10,307	10,307	10,307	10,307	10,307	10,307	10,307	**123,678**
CAPX2020 - La Crosse MISO	Property Tax Expense	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	**1,114,847**
CAPX2020 - La Crosse MISO	OATT Credit													
CAPX2020 - La Crosse MISO	Total Revenue Requirement	589,347	588,322	587,297	586,271	585,246	584,221	583,195	582,170	581,144	580,119	579,094	578,068	**7,004,494**
CAPX2020 - La Crosse MISO	**Rider Revenue Requirement**	430,754	430,005	429,255	428,506	427,756	427,007	426,257	425,508	424,758	424,009	423,259	422,510	**5,119,584**
CAPX2020 - La Crosse MISO - WI	CWIP Balance	(6,781)	(6,781)	(6,781)	(6,781)	0	0	0	0	0	0	0	0	**0**
CAPX2020 - La Crosse MISO - WI	Plant In-Service	136,350,767	136,378,001	136,378,696	136,382,493	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	**136,382,629**
CAPX2020 - La Crosse MISO - WI	Depreciation Reserve	18,821,103	19,116,878	19,412,684	19,708,491	20,004,297	20,300,104	20,595,910	20,891,717	21,187,523	21,483,330	21,779,136	22,074,943	**22,074,943**
CAPX2020 - La Crosse MISO - WI	Accumulated Deferred Taxes	33,407,805	33,414,887	33,421,969	33,429,051	33,436,133	33,443,215	33,450,297	33,457,379	33,464,461	33,471,543	33,478,625	33,485,707	**33,485,707**
CAPX2020 - La Crosse MISO - WI	Average Rate Base	84,264,096	83,973,725	83,684,817	83,384,174	83,086,643	82,787,213	82,484,325	82,181,436	81,878,548	81,575,659	81,272,771	80,969,882	**80,969,882**
CAPX2020 - La Crosse MISO - WI	Tax Depreciation Expense	322,440	322,440	322,440	322,440	322,440	322,440	322,440	322,440	322,440	322,440	322,440	322,440	**3,869,281**
CAPX2020 - La Crosse MISO - WI	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO - WI	Debt Return	157,995	157,451	156,909	156,345	155,787	155,226	154,658	154,090	153,522	152,954	152,386	151,819	**1,859,144**
CAPX2020 - La Crosse MISO - WI	Equity Return	334,248	333,096	331,950	330,757	329,577	328,389	327,188	325,986	324,785	323,583	322,382	321,181	**3,933,122**
CAPX2020 - La Crosse MISO - WI	Current Income Tax Requirement	126,908	126,456	126,006	125,525	125,049	124,570	124,085	123,601	123,116	122,632	122,147	121,662	**1,491,757**
CAPX2020 - La Crosse MISO - WI	Book Depreciation	295,743	295,775	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	**3,549,583**
CAPX2020 - La Crosse MISO - WI	AFUDC													
CAPX2020 - La Crosse MISO - WI	Deferred Taxes	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	7,082	**84,984**
CAPX2020 - La Crosse MISO - WI	Property Tax Expense	168,487	168,487	168,487	168,487	168,487	168,487	168,487	168,487	168,487	168,487	168,487	168,487	**2,021,845**
CAPX2020 - La Crosse MISO - WI	OATT Credit													
CAPX2020 - La Crosse MISO - WI	Total Revenue Requirement	1,090,463	1,088,346	1,086,241	1,084,003	1,081,789	1,079,561	1,077,307	1,075,053	1,072,799	1,070,545	1,068,291	1,066,037	**12,940,434**
CAPX2020 - La Crosse MISO - WI	**Rider Revenue Requirement**	797,019	795,472	793,933	792,298	790,680	789,051	787,404	785,756	784,109	782,461	780,814	779,166	**9,458,162**
Huntley - Wilmarth	CWIP Balance	33,095,054	34,271,252	36,283,709	37,165,311	38,775,852	40,885,414	42,394,684	44,103,798	45,408,340	46,284,290	47,097,475	(44,661)	**(44,661)**
Huntley - Wilmarth	Plant In-Service	3,899,468	3,899,211	3,899,226	3,888,764	3,888,763	3,888,763	3,991,921	4,005,171	4,114,955	4,144,294	4,153,758	51,829,060	**51,829,060**
Huntley - Wilmarth	Depreciation Reserve	24,101	26,634	29,167	31,700	34,233	36,766	39,299	41,833	44,366	46,899	49,432	96,999	**96,999**
Huntley - Wilmarth	Accumulated Deferred Taxes	(167,168)	(145,945)	(124,722)	(103,499)	(82,275)	(61,052)	(39,829)	(18,606)	2,617	23,841	45,064	66,287	**66,287**
Huntley - Wilmarth	Average Rate Base	36,103,804	37,703,070	39,273,520	40,691,570	41,908,654	43,744,948	45,582,187	47,225,827	48,770,415	49,906,466	50,746,679	51,378,313	**51,378,313**
Huntley - Wilmarth	Tax Depreciation Expense	217,842	217,842	217,842	217,842	217,842	217,842	217,842	217,842	217,842	217,842	217,842	217,842	**2,614,106**
Huntley - Wilmarth	CPI-TAX INTEREST	126,726	79,035	115,485	131,043	143,807	151,061	149,819	155,538	160,943	165,011	168,293	85,507	**1,632,269**
Huntley - Wilmarth	Debt Return	67,695	70,693	73,638	76,297	78,579	82,022	85,467	88,548	91,445	93,575	95,150	96,334	**999,441**
Huntley - Wilmarth	Equity Return	143,212	149,556	155,785	161,410	166,238	173,522	180,809	187,329	193,456	197,962	201,295	203,801	**2,114,374**
Huntley - Wilmarth	Current Income Tax Requirement	30,595	13,917	31,132	39,676	46,772	52,636	55,075	60,011	64,663	68,121	70,789	56,572	**589,960**
Huntley - Wilmarth	Book Depreciation	2,533	2,533	2,533	2,533	2,533	2,533	2,533	2,533	2,533	2,533	2,533	47,567	**75,431**
Huntley - Wilmarth	AFUDC													
Huntley - Wilmarth	Deferred Taxes	21,223	21,223	21,223	21,223	21,223	21,223	21,223	21,223	21,223	21,223	21,223	21,223	**254,678**
Huntley - Wilmarth	Property Tax Expense	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	4,818	**57,821**
Huntley - Wilmarth	OATT Credit													
Huntley - Wilmarth	Total Revenue Requirement	270,076	262,741	289,130	305,958	320,163	336,754	349,925	364,463	378,138	388,233	395,809	430,315	**4,091,706**
Huntley - Wilmarth	**Rider Revenue Requirement**	197,398	192,037	211,325	223,624	234,007	246,134	255,760	266,386	276,381	283,759	289,297	314,518	**2,990,627**

Project	Rider Components	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
CAPX2020 - La Crosse MISO	CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CAPX2020 - La Crosse MISO	Plant In-Service	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	**75,185,211**
CAPX2020 - La Crosse MISO	Depreciation Reserve	10,164,006	10,291,488	10,418,971	10,546,454	10,673,936	10,801,419	10,928,902	11,056,385	11,183,867	11,311,350	11,438,833	11,566,315	**11,566,315**
CAPX2020 - La Crosse MISO	Accumulated Deferred Taxes	17,108,683	17,119,299	17,129,916	17,140,532	17,151,148	17,161,764	17,172,209	17,182,826	17,193,613	17,204,058	17,214,846	17,225,291	**17,225,291**
CAPX2020 - La Crosse MISO	Average Rate Base	47,976,264	47,838,165	47,700,066	47,561,967	47,423,868	47,285,769	47,147,841	47,009,742	46,871,472	46,733,545	46,595,274	46,457,347	**46,457,347**
CAPX2020 - La Crosse MISO	Tax Depreciation Expense	165,355	165,355	165,355	165,355	165,355	165,355	165,355	165,355	165,355	165,355	165,355	165,355	**1,984,255**
CAPX2020 - La Crosse MISO	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO	Debt Return	89,955	89,697	89,438	89,179	88,920	88,661	88,402	88,143	87,884	87,625	87,366	87,108	**1,062,377**
CAPX2020 - La Crosse MISO	Equity Return	190,306	189,758	189,210	188,662	188,115	187,567	187,020	186,472	185,924	185,376	184,828	184,281	**2,247,519**
CAPX2020 - La Crosse MISO	Current Income Tax Requirement	65,766	65,546	65,325	65,104	64,883	64,662	64,441	64,220	63,999	63,778	63,557	63,336	**774,616**
CAPX2020 - La Crosse MISO	Book Depreciation	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	**1,529,792**
CAPX2020 - La Crosse MISO	AFUDC													
CAPX2020 - La Crosse MISO	Deferred Taxes	10,616	10,616	10,616	10,616	10,616	10,616	10,616	10,616	10,616	10,616	10,616	10,616	**127,395**
CAPX2020 - La Crosse MISO	Property Tax Expense	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	**1,114,847**
CAPX2020 - La Crosse MISO	OATT Credit													
CAPX2020 - La Crosse MISO	Total Revenue Requirement	577,031	576,003	574,975	573,948	572,920	571,892	570,866	569,838	568,809	567,783	566,754	565,728	**6,856,547**
CAPX2020 - La Crosse MISO	**Rider Revenue Requirement**	422,098	421,347	420,595	419,843	419,091	418,340	417,589	416,837	416,084	415,334	414,581	413,830	**5,015,570**
CAPX2020 - La Crosse MISO - WI	CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CAPX2020 - La Crosse MISO - WI	Plant In-Service	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	**136,382,629**
CAPX2020 - La Crosse MISO - WI	Depreciation Reserve	22,370,749	22,666,556	22,962,362	23,258,168	23,553,975	23,849,781	24,145,588	24,441,394	24,737,201	25,033,007	25,328,814	25,624,620	**25,624,620**
CAPX2020 - La Crosse MISO - WI	Accumulated Deferred Taxes	33,492,478	33,498,938	33,505,398	33,511,858	33,518,318	33,524,779	33,531,134	33,537,595	33,544,159	33,550,515	33,557,079	33,563,435	**33,563,435**
CAPX2020 - La Crosse MISO - WI	Average Rate Base	80,667,305	80,365,038	80,062,772	79,760,505	79,458,239	79,155,972	78,853,810	78,551,543	78,249,172	77,947,010	77,644,639	77,342,477	**77,342,477**
CAPX2020 - La Crosse MISO - WI	Tax Depreciation Expense	320,253	320,253	320,253	320,253	320,253	320,253	320,253	320,253	320,253	320,253	320,253	320,253	**3,843,041**
CAPX2020 - La Crosse MISO - WI	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO - WI	Debt Return	151,251	150,684	150,118	149,551	148,984	148,417	147,851	147,284	146,717	146,151	145,584	145,017	**1,777,610**
CAPX2020 - La Crosse MISO - WI	Equity Return	319,980	318,781	317,582	316,383	315,184	313,985	312,787	311,588	310,388	309,190	307,990	306,792	**3,760,632**
CAPX2020 - La Crosse MISO - WI	Current Income Tax Requirement	121,809	121,326	120,842	120,359	119,875	119,391	118,908	118,424	117,941	117,457	116,973	116,490	**1,429,795**
CAPX2020 - La Crosse MISO - WI	Book Depreciation	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	**3,549,678**
CAPX2020 - La Crosse MISO - WI	AFUDC													
CAPX2020 - La Crosse MISO - WI	Deferred Taxes	6,460	6,460	6,460	6,460	6,460	6,460	6,460	6,460	6,460	6,460	6,460	6,460	**77,521**
CAPX2020 - La Crosse MISO - WI	Property Tax Expense	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	**2,022,283**
CAPX2020 - La Crosse MISO - WI	OATT Credit													
CAPX2020 - La Crosse MISO - WI	Total Revenue Requirement	1,063,831	1,061,582	1,059,332	1,057,083	1,054,834	1,052,584	1,050,336	1,048,086	1,045,836	1,043,588	1,041,338	1,039,089	**12,617,519**
CAPX2020 - La Crosse MISO - WI	**Rider Revenue Requirement**	778,193	776,548	774,903	773,257	771,612	769,966	768,322	766,676	765,030	763,385	761,739	760,095	**9,229,727**
Huntley - Wilmarth	CWIP Balance	(44,661)	(44,661)	(44,661)										
Huntley - Wilmarth	Plant In-Service	52,844,243	53,859,425	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	**54,874,608**
Huntley - Wilmarth	Depreciation Reserve	190,017	283,870	378,559	473,666	568,772	663,879	758,985	854,092	949,198	1,044,305	1,139,412	1,234,518	**1,234,518**
Huntley - Wilmarth	Accumulated Deferred Taxes	121,099	209,501	297,902	386,303	474,704	563,106	650,081	738,483	828,310	915,285	1,005,112	1,092,088	**1,092,088**
Huntley - Wilmarth	Average Rate Base	52,027,383	52,860,729	53,693,239	54,039,862	53,878,684	53,695,177	53,513,095	53,329,587	53,144,653	52,962,571	52,777,637	52,595,555	**52,595,555**
Huntley - Wilmarth	Tax Depreciation Expense	409,970	409,970	409,970	409,970	409,970	409,970	409,970	409,970	409,970	409,970	409,970	409,970	**4,919,639**
Huntley - Wilmarth	CPI-TAX INTEREST													
Huntley - Wilmarth	Debt Return	97,551	99,114	100,675	101,325	101,023	100,678	100,337	99,993	99,646	99,305	98,958	98,617	**1,197,222**
Huntley - Wilmarth	Equity Return	206,375	209,681	212,983	214,358	213,719	212,991	212,269	211,541	210,807	210,085	209,351	208,629	**2,532,789**
Huntley - Wilmarth	Current Income Tax Requirement	(8,944)	(7,274)	(5,605)	(4,882)	(5,140)	(5,434)	(5,725)	(6,019)	(6,314)	(6,606)	(6,902)	(7,193)	**(76,038)**
Huntley - Wilmarth	Book Depreciation	93,018	93,853	94,689	95,107	95,107	95,107	95,107	95,107	95,107	95,107	95,107	95,107	**1,137,519**
Huntley - Wilmarth	AFUDC													
Huntley - Wilmarth	Deferred Taxes	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	88,401	**1,060,816**
Huntley - Wilmarth	Property Tax Expense	64,043	64,043	64,043	64,043	64,043	64,043	64,043	64,043	64,043	64,043	64,043	64,043	**768,522**
Huntley - Wilmarth	OATT Credit													
Huntley - Wilmarth	Total Revenue Requirement	540,445	547,819	555,186	558,352	557,153	555,787	554,432	553,066	551,690	550,335	548,959	547,604	**6,620,830**
Huntley - Wilmarth	**Rider Revenue Requirement**	395,336	400,730	406,119	408,435	407,558	406,559	405,568	404,569	403,562	402,571	401,564	400,573	**4,843,143**

Project	Rider Components	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
CAPX2020 - La Crosse MISO	CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CAPX2020 - La Crosse MISO	Plant In-Service	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	75,185,211	**75,185,211**
CAPX2020 - La Crosse MISO	Depreciation Reserve	11,693,798	11,821,281	11,948,763	12,076,246	12,203,729	12,331,211	12,458,694	12,586,177	12,713,660	12,841,142	12,968,625	13,096,108	**13,096,108**
CAPX2020 - La Crosse MISO	Accumulated Deferred Taxes	17,236,263	17,247,799	17,258,968	17,270,503	17,281,673	17,293,208	17,304,378	17,315,730	17,327,266	17,338,435	17,349,971	17,361,140	**17,361,140**
CAPX2020 - La Crosse MISO	Average Rate Base	46,318,892	46,179,873	46,041,221	45,902,203	45,763,551	45,624,533	45,485,881	45,347,046	45,208,027	45,069,375	44,930,357	44,791,705	**44,791,705**
CAPX2020 - La Crosse MISO	Tax Depreciation Expense	167,981	167,981	167,981	167,981	167,981	167,981	167,981	167,981	167,981	167,981	167,981	167,981	**2,015,770**
CAPX2020 - La Crosse MISO	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO	Debt Return	86,848	86,587	86,327	86,067	85,807	85,546	85,286	85,026	84,765	84,505	84,244	83,984	**1,024,992**
CAPX2020 - La Crosse MISO	Equity Return	183,732	183,180	182,630	182,079	181,529	180,977	180,427	179,877	179,325	178,775	178,224	177,674	**2,168,429**
CAPX2020 - La Crosse MISO	Current Income Tax Requirement	62,352	62,130	61,908	61,686	61,464	61,241	61,020	60,797	60,575	60,353	60,131	59,909	**733,567**
CAPX2020 - La Crosse MISO	Book Depreciation	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	127,483	**1,529,792**
CAPX2020 - La Crosse MISO	AFUDC													
CAPX2020 - La Crosse MISO	Deferred Taxes	11,352	11,352	11,352	11,352	11,352	11,352	11,352	11,352	11,352	11,352	11,352	11,352	**136,229**
CAPX2020 - La Crosse MISO	Property Tax Expense	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	92,904	**1,114,847**
CAPX2020 - La Crosse MISO	OATT Credit													
CAPX2020 - La Crosse MISO	Total Revenue Requirement	564,671	563,636	562,605	561,570	560,538	559,504	558,472	557,439	556,404	555,373	554,338	553,306	**6,707,857**
CAPX2020 - La Crosse MISO	**Rider Revenue Requirement**	412,368	411,613	410,859	410,104	409,350	408,595	407,841	407,087	406,331	405,578	404,822	404,069	**4,898,618**
CAPX2020 - La Crosse MISO - WI	CWIP Balance	0	0	0	0	0	0	0	0	0	0	0	0	**0**
CAPX2020 - La Crosse MISO - WI	Plant In-Service	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	136,382,629	**136,382,629**
CAPX2020 - La Crosse MISO - WI	Depreciation Reserve	25,920,427	26,216,233	26,512,040	26,807,846	27,103,653	27,399,459	27,695,266	27,991,072	28,286,879	28,582,685	28,878,492	29,174,298	**29,174,298**
CAPX2020 - La Crosse MISO - WI	Accumulated Deferred Taxes	33,569,857	33,576,341	33,582,619	33,589,103	33,595,381	33,601,865	33,608,143	33,614,524	33,621,008	33,627,286	33,633,770	33,640,048	**33,640,048**
CAPX2020 - La Crosse MISO - WI	Average Rate Base	77,040,248	76,737,958	76,435,873	76,133,583	75,831,498	75,529,208	75,227,123	74,924,936	74,622,645	74,320,560	74,018,270	73,716,185	**73,716,185**
CAPX2020 - La Crosse MISO - WI	Tax Depreciation Expense	319,941	319,941	319,941	319,941	319,941	319,941	319,941	319,941	319,941	319,941	319,941	319,941	**3,839,290**
CAPX2020 - La Crosse MISO - WI	CPI-TAX INTEREST													
CAPX2020 - La Crosse MISO - WI	Debt Return	144,450	143,884	143,317	142,750	142,184	141,617	141,051	140,484	139,917	139,351	138,784	138,218	**1,696,009**
CAPX2020 - La Crosse MISO - WI	Equity Return	305,593	304,394	303,196	301,997	300,798	299,599	298,401	297,202	296,003	294,805	293,606	292,408	**3,588,001**
CAPX2020 - La Crosse MISO - WI	Current Income Tax Requirement	116,101	115,617	115,134	114,650	114,167	113,683	113,200	112,716	112,232	111,749	111,265	110,782	**1,361,295**
CAPX2020 - La Crosse MISO - WI	Book Depreciation	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	295,806	**3,549,678**
CAPX2020 - La Crosse MISO - WI	AFUDC													
CAPX2020 - La Crosse MISO - WI	Deferred Taxes	6,381	6,381	6,381	6,381	6,381	6,381	6,381	6,381	6,381	6,381	6,381	6,381	**76,573**
CAPX2020 - La Crosse MISO - WI	Property Tax Expense	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	168,524	**2,022,283**
CAPX2020 - La Crosse MISO - WI	OATT Credit													
CAPX2020 - La Crosse MISO - WI	Total Revenue Requirement	1,036,855	1,034,606	1,032,358	1,030,108	1,027,860	1,025,611	1,023,363	1,021,114	1,018,864	1,016,616	1,014,367	1,012,119	**12,293,839**
CAPX2020 - La Crosse MISO - WI	**Rider Revenue Requirement**	757,195	755,552	753,911	752,268	750,626	748,984	747,342	745,700	744,057	742,415	740,772	739,131	**8,977,953**
Huntley - Wilmarth	CWIP Balance													
Huntley - Wilmarth	Plant In-Service	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	54,874,608	**54,874,608**
Huntley - Wilmarth	Depreciation Reserve	1,329,625	1,424,731	1,519,838	1,614,944	1,710,051	1,805,157	1,900,264	1,995,371	2,090,477	2,185,584	2,280,690	2,375,797	**2,375,797**
Huntley - Wilmarth	Accumulated Deferred Taxes	1,175,633	1,255,263	1,332,365	1,411,994	1,489,096	1,568,726	1,645,828	1,724,194	1,803,823	1,880,925	1,960,555	2,037,657	**2,037,657**
Huntley - Wilmarth	Average Rate Base	52,416,903	52,242,167	52,069,959	51,895,222	51,723,014	51,548,278	51,376,069	51,202,597	51,027,861	50,855,652	50,680,916	50,508,708	**50,508,708**
Huntley - Wilmarth	Tax Depreciation Expense	374,483	374,483	374,483	374,483	374,483	374,483	374,483	374,483	374,483	374,483	374,483	374,483	**4,493,794**
Huntley - Wilmarth	CPI-TAX INTEREST													
Huntley - Wilmarth	Debt Return	98,282	97,954	97,631	97,304	96,981	96,653	96,330	96,005	95,677	95,354	95,027	94,704	**1,157,901**
Huntley - Wilmarth	Equity Return	207,920	207,227	206,544	205,851	205,168	204,475	203,792	203,104	202,411	201,727	201,034	200,351	**2,449,604**
Huntley - Wilmarth	Current Income Tax Requirement	2,787	2,508	2,232	1,952	1,677	1,397	1,122	844	565	289	10	(266)	**15,117**
Huntley - Wilmarth	Book Depreciation	95,107	95,107	95,107	95,107	95,107	95,107	95,107	95,107	95,107	95,107	95,107	95,107	**1,141,279**
Huntley - Wilmarth	AFUDC													
Huntley - Wilmarth	Deferred Taxes	78,366	78,366	78,366	78,366	78,366	78,366	78,366	78,366	78,366	78,366	78,366	78,366	**940,389**
Huntley - Wilmarth	Property Tax Expense	67,807	67,807	67,807	67,807	67,807	67,807	67,807	67,807	67,807	67,807	67,807	67,807	**813,681**
Huntley - Wilmarth	OATT Credit													
Huntley - Wilmarth	Total Revenue Requirement	550,268	548,968	547,686	546,386	545,105	543,804	542,523	541,232	539,932	538,650	537,350	536,068	**6,517,972**
Huntley - Wilmarth	**Rider Revenue Requirement**	401,850	400,901	399,965	399,015	398,079	397,130	396,194	395,251	394,302	393,366	392,416	391,480	**4,759,949**

Project	Rider Components	Jan - 2019	Feb - 2019	Mar - 2019	Apr - 2019	May - 2019	Jun - 2019	Jul - 2019	Aug - 2019	Sep - 2019	Oct - 2019	Nov - 2019	Dec - 2019	2019
LaCrosse - Madison	CWIP Balance	1,630,735	1,517,334	1,605,129	1,985,729	1,178,117	1,177,802	1,177,674	1,186,837	1,186,775	1,216,422	1,216,228	1,215,151	**1,215,151**
LaCrosse - Madison	Plant In-Service	164,337,087	165,148,161	165,525,283	165,897,097	167,132,720	167,711,741	168,423,162	168,916,975	169,311,067	169,857,798	172,419,303	172,767,020	**172,767,020**
LaCrosse - Madison	Depreciation Reserve	568,600	937,132	1,306,479	1,676,121	2,046,728	2,418,502	2,791,581	3,165,892	3,540,867	3,916,272	4,292,286	4,668,869	**4,668,869**
LaCrosse - Madison	Accumulated Deferred Taxes	2,551,845	3,923,631	5,295,417	6,667,203	8,038,989	9,410,775	10,782,560	12,154,346	13,526,132	14,897,918	16,269,704	17,641,490	**17,641,490**
LaCrosse - Madison	Average Rate Base	161,807,645	162,326,055	161,166,624	160,034,009	158,882,311	157,642,694	156,543,481	155,405,134	154,107,208	152,845,436	152,666,786	152,372,676	**152,372,676**
LaCrosse - Madison	Tax Depreciation Expense	5,271,032	5,271,032	5,271,032	5,271,032	5,271,032	5,271,032	5,271,032	5,271,032	5,271,032	5,271,032	5,271,032	5,271,032	**63,252,380**
LaCrosse - Madison	CPI-TAX INTEREST													
LaCrosse - Madison	Debt Return	303,389	304,361	302,187	300,064	297,904	295,580	293,519	291,385	288,951	286,585	286,250	285,699	**3,535,875**
LaCrosse - Madison	Equity Return	641,837	643,893	639,294	634,802	630,233	625,316	620,956	616,440	611,292	606,287	605,578	604,412	**7,480,340**
LaCrosse - Madison	Current Income Tax Requirement	(1,167,224)	(1,164,402)	(1,165,929)	(1,167,622)	(1,169,076)	(1,170,588)	(1,171,820)	(1,173,145)	(1,174,953)	(1,176,799)	(1,176,839)	(1,177,080)	**(14,055,477)**
LaCrosse - Madison	Book Depreciation	363,594	368,532	369,347	369,642	370,606	371,774	373,080	374,311	374,975	375,405	376,013	376,584	**4,463,863**
LaCrosse - Madison	AFUDC													
LaCrosse - Madison	Deferred Taxes	1,371,786	1,371,786	1,371,786	1,371,786	1,371,786	1,371,786	1,371,786	1,371,786	1,371,786	1,371,786	1,371,786	1,371,786	**16,461,432**
LaCrosse - Madison	Property Tax Expense	206,765	206,765	206,765	206,765	206,765	206,765	206,765	206,765	206,765	206,765	206,765	206,765	**2,481,184**
LaCrosse - Madison	OATT Credit													
LaCrosse - Madison	Total Revenue Requirement	1,720,147	1,730,935	1,723,451	1,715,437	1,708,219	1,700,633	1,694,286	1,687,542	1,678,816	1,670,029	1,669,554	1,668,166	**20,367,217**
LaCrosse - Madison	**Rider Revenue Requirement**	1,260,378	1,268,282	1,262,799	1,256,927	1,251,638	1,246,080	1,241,429	1,236,487	1,230,094	1,223,655	1,223,307	1,222,290	**14,923,365**
Total	CWIP Balance	26,047,065	26,905,401	27,898,454	29,339,541	29,431,702	29,859,837	30,671,714	29,876,999	31,325,928	33,669,456	32,751,827	32,320,983	**32,320,983**
Total	Plant In-Service	1,175,805,765	1,176,735,550	1,177,122,864	1,177,498,451	1,178,783,074	1,179,995,649	1,180,909,143	1,182,944,768	1,183,321,218	1,184,134,459	1,190,328,557	1,193,215,802	**1,193,215,802**
Total	Depreciation Reserve	84,611,596	86,812,772	89,014,887	91,217,310	93,420,696	95,627,825	97,839,038	100,061,255	102,293,717	104,526,691	106,763,455	109,016,962	**109,016,962**
Total	Accumulated Deferred Taxes	220,277,057	222,373,496	224,469,934	226,566,373	228,662,812	230,759,250	232,855,689	234,952,128	237,048,566	239,145,005	241,241,444	243,337,882	**243,337,882**
Total	Average Rate Base	892,113,455	895,709,430	892,995,590	890,295,403	887,592,788	884,799,839	882,177,270	879,347,257	876,556,624	874,718,541	874,603,852	874,128,713	**874,128,713**
Total	Tax Depreciation Expense	9,703,469	9,703,469	9,703,469	9,703,469	9,703,469	9,703,469	9,703,469	9,703,469	9,703,469	9,703,469	9,703,469	9,703,469	**116,441,631**
Total	CPI-TAX INTEREST	7,587	8,608	(78,417)	9,994	11,459	12,701	11,680	12,573	13,652	27,218	24,004	27,968	**89,027**
Total	Debt Return	1,672,713	1,679,455	1,674,367	1,669,304	1,664,236	1,659,000	1,654,082	1,648,776	1,643,544	1,640,097	1,639,882	1,638,991	**19,884,448**
Total	Equity Return	3,538,717	3,552,981	3,542,216	3,531,505	3,520,785	3,509,706	3,499,303	3,488,077	3,477,008	3,469,717	3,469,262	3,467,377	**42,066,654**
Total	Current Income Tax Requirement	(752,014)	(743,887)	(782,952)	(751,487)	(754,832)	(757,290)	(760,250)	(759,980)	(759,877)	(757,140)	(757,090)	(749,499)	**(9,086,296)**
Total	Book Depreciation	2,196,313	2,201,176	2,202,114	2,202,423	2,203,386	2,207,129	2,211,213	2,222,216	2,232,462	2,232,974	2,236,764	2,253,506	**26,601,678**
Total	AFUDC	2,190	2,673	2,968	3,999	5,509	6,829	6,706	7,894	10,295	17,614	23,376	29,170	**119,224**
Total	Deferred Taxes	2,096,439	2,096,439	2,096,439	2,096,439	2,096,439	2,096,439	2,096,439	2,096,439	2,096,439	2,096,439	2,096,439	2,096,439	**25,157,264**
Total	Property Tax Expense	1,494,883	1,494,883	1,494,883	1,494,883	1,494,883	1,494,883	1,494,883	1,494,883	1,494,883	1,494,883	1,494,883	1,494,883	**17,938,591**
Total	OATT Credit	170,880	170,192	169,785	169,379	168,973	168,567	168,161	167,755	167,349	166,943	167,459	168,136	**2,023,581**
Total	Operating Expenses					12,532		73,780	24,593	24,593	24,593	24,593	24,593	**209,278**
Total	Total Revenue Requirement	8,646,744	9,281,109	8,878,629	9,242,295	9,328,447	9,215,976	9,316,419	9,466,258	9,544,554	8,243,268	8,959,021	9,147,250	**109,269,969**
Total	**Rider Revenue Requirement**	6,186,639	6,651,362	6,356,210	6,621,538	6,685,879	6,595,469	6,685,534	6,770,234	6,814,100	5,844,860	6,355,926	6,482,438	**78,050,188**

Project	Rider Components	Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020	2020
LaCrosse - Madison	CWIP Balance	1,215,084	1,185,465	1,185,465	1,185,464	1,185,464	1,185,464	1,185,464	1,185,464	1,165,810	1,185,094	1,185,094	1,185,012	**1,185,012**
LaCrosse - Madison	Plant In-Service	172,820,078	173,166,531	173,128,103	173,230,881	173,280,856	173,373,327	173,465,503	173,555,031	173,701,143	173,917,931	173,975,064	174,135,446	**174,135,446**
LaCrosse - Madison	Depreciation Reserve	5,046,021	5,423,403	5,800,934	6,178,518	6,556,142	6,933,838	7,311,642	7,689,550	8,067,647	8,446,049	8,824,647	9,203,305	**9,203,305**
LaCrosse - Madison	Accumulated Deferred Taxes	17,817,242	17,992,993	18,078,034	18,256,620	18,429,536	18,608,123	18,781,039	18,956,790	19,135,377	19,308,293	19,486,879	19,659,796	**19,659,796**
LaCrosse - Madison	Average Rate Base	151,421,856	150,965,874	150,642,580	150,118,611	149,644,465	149,159,442	148,701,099	148,238,344	147,789,749	147,419,848	147,009,364	146,566,536	**146,566,536**
LaCrosse - Madison	Tax Depreciation Expense	1,004,836	1,004,836	1,004,836	1,004,836	1,004,836	1,004,836	1,004,836	1,004,836	1,004,836	1,004,836	1,004,836	1,004,836	**12,058,037**
LaCrosse - Madison	CPI-TAX INTEREST													
LaCrosse - Madison	Debt Return	283,916	283,061	282,455	281,472	280,583	279,674	278,815	277,947	277,106	276,412	275,643	274,812	**3,351,896**
LaCrosse - Madison	Equity Return	600,640	598,831	597,549	595,470	593,590	591,666	589,848	588,012	586,233	584,765	583,137	581,381	**7,091,122**
LaCrosse - Madison	Current Income Tax Requirement	59,981	59,344	58,887	58,071	57,327	56,581	55,891	55,193	54,551	54,082	53,505	52,820	**676,233**
LaCrosse - Madison	Book Depreciation	377,151	377,382	377,531	377,585	377,623	377,697	377,803	377,908	378,097	378,402	378,599	378,657	**4,534,436**
LaCrosse - Madison	AFUDC													
LaCrosse - Madison	Deferred Taxes	175,751	175,751	175,751	175,751	175,751	175,751	175,751	175,751	175,751	175,751	175,751	175,751	**2,109,016**
LaCrosse - Madison	Property Tax Expense	216,851	216,851	216,851	216,851	216,851	216,851	216,851	216,851	216,851	216,851	216,851	216,851	**2,602,207**
LaCrosse - Madison	OATT Credit													
LaCrosse - Madison	Total Revenue Requirement	1,714,290	1,711,221	1,709,024	1,705,200	1,701,726	1,698,219	1,694,958	1,691,662	1,688,588	1,686,264	1,683,485	1,680,272	**20,364,909**
LaCrosse - Madison	**Rider Revenue Requirement**	1,255,605	1,253,358	1,251,748	1,248,948	1,246,403	1,243,835	1,241,446	1,239,031	1,236,780	1,235,078	1,233,043	1,230,690	**14,915,964**
Total	CWIP Balance	32,442,891	33,544,417	34,982,651	32,959,689	34,952,797	41,375,630	47,213,285	53,795,758	58,774,620	63,575,583	67,482,253	69,024,497	**69,024,497**
Total	Plant In-Service	1,194,216,877	1,194,746,433	1,195,177,296	1,198,030,093	1,199,097,948	1,199,324,295	1,199,498,598	1,199,654,839	1,199,815,460	1,199,496,022	1,199,633,621	1,203,482,403	**1,203,482,403**
Total	Depreciation Reserve	111,280,528	113,544,708	115,809,113	118,076,284	120,347,575	122,620,389	124,893,367	127,166,471	129,439,766	131,712,722	133,985,567	136,285,746	**136,285,746**
Total	Accumulated Deferred Taxes	243,981,337	244,624,792	244,939,626	245,593,351	246,226,536	246,880,261	247,513,445	248,156,900	248,810,625	249,443,810	250,097,535	250,730,720	**250,730,720**
Total	Average Rate Base	872,289,922	870,437,899	869,608,863	868,038,816	867,081,798	869,011,092	872,435,580	875,894,420	878,906,594	880,810,788	882,147,059	883,945,010	**883,945,010**
Total	Tax Depreciation Expense	4,622,945	4,622,945	4,622,945	4,622,945	4,622,945	4,622,945	4,622,945	4,622,945	4,622,945	4,622,945	4,622,945	4,622,945	**55,475,337**
Total	CPI-TAX INTEREST	29,074	(16,299)	17,212	17,958	19,586	31,070	48,192	70,848	88,350	138,126	113,933	126,926	**684,975**
Total	Debt Return	1,635,544	1,632,071	1,630,517	1,627,573	1,625,778	1,629,396	1,635,817	1,642,302	1,647,950	1,651,520	1,654,026	1,657,397	**19,669,890**
Total	Equity Return	3,460,083	3,452,737	3,449,448	3,443,221	3,439,424	3,447,077	3,460,661	3,474,381	3,486,329	3,493,883	3,499,183	3,506,315	**41,612,744**
Total	Current Income Tax Requirement	715,236	694,219	706,500	705,405	706,192	714,525	726,977	741,700	753,655	776,643	768,977	788,120	**8,798,149**
Total	Book Depreciation	2,263,567	2,264,180	2,264,405	2,267,171	2,271,292	2,272,814	2,272,978	2,273,104	2,273,295	2,272,956	2,272,845	2,300,179	**27,268,785**
Total	AFUDC	22,655	(51,050)	156	333	(3,445)	(167)				59,058	405	3,995	**31,941**
Total	Deferred Taxes	643,455	643,455	643,455	643,455	643,455	643,455	643,455	643,455	643,455	643,455	643,455	643,455	**7,721,460**
Total	Property Tax Expense	1,489,075	1,489,075	1,489,075	1,489,075	1,489,075	1,489,075	1,489,075	1,489,075	1,489,075	1,489,075	1,489,075	1,489,075	**17,868,903**
Total	OATT Credit	155,998	155,590	155,282	154,921	154,564	154,250	153,939	153,580	153,219	152,862	152,501	152,144	**1,848,849**
Total	Operating Expenses	23,743	80,378	106,805	164,027	58,305	98,595	72,553	97,917	161,975	115,586	215,309	142,419	**1,337,612**
Total	Total Revenue Requirement	10,003,813	9,646,323	9,797,758	10,655,091	9,824,228	10,457,409	11,909,366	10,617,338	9,786,100	10,251,564	10,248,213	9,960,526	**123,157,729**
Total	**Rider Revenue Requirement**	7,157,274	6,978,308	7,047,442	7,689,208	7,055,692	7,529,088	8,586,400	7,647,770	7,057,426	7,333,906	7,413,902	7,183,137	**88,679,553**

Project	Rider Components	Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021	2021
LaCrosse - Madison	CWIP Balance	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	**1,185,012**
LaCrosse - Madison	Plant In-Service	174,138,046	171,274,318	171,488,850	171,509,898	171,527,770	171,543,159	171,560,928	171,584,801	170,655,391	170,885,739	171,002,371	171,036,996	**171,036,996**
LaCrosse - Madison	Depreciation Reserve	9,581,760	9,956,766	10,328,578	10,700,660	11,072,774	11,444,915	11,817,084	12,189,281	12,560,327	12,930,238	13,300,192	13,670,171	**13,670,171**
LaCrosse - Madison	Accumulated Deferred Taxes	19,827,229	19,980,673	20,134,118	20,287,563	20,441,008	20,594,453	20,747,897	20,901,342	21,054,787	21,208,232	21,361,677	21,515,121	**21,515,121**
LaCrosse - Madison	Average Rate Base	146,101,997	144,141,258	142,289,807	141,882,204	141,376,121	140,867,180	140,358,158	139,853,351	138,875,517	138,002,062	137,652,175	137,204,393	**137,204,393**
LaCrosse - Madison	Tax Depreciation Expense	920,082	920,082	920,082	920,082	920,082	920,082	920,082	920,082	920,082	920,082	920,082	920,082	**11,040,979**
LaCrosse - Madison	CPI-TAX INTEREST		5,414											**5,414**
LaCrosse - Madison	Debt Return	273,941	270,265	266,793	266,029	265,080	264,126	263,172	262,225	260,392	258,754	258,098	257,258	**3,166,133**
LaCrosse - Madison	Equity Return	579,538	571,760	564,416	562,799	560,792	558,773	556,754	554,752	550,873	547,408	546,020	544,244	**6,698,130**
LaCrosse - Madison	Current Income Tax Requirement	77,184	74,839	68,405	67,862	67,065	66,262	65,458	64,662	62,633	60,778	60,235	59,529	**794,912**
LaCrosse - Madison	Book Depreciation	378,455	375,006	371,812	372,083	372,113	372,142	372,169	372,197	371,046	369,911	369,953	369,979	**4,466,866**
LaCrosse - Madison	AFUDC													
LaCrosse - Madison	Deferred Taxes	153,445	153,445	153,445	153,445	153,445	153,445	153,445	153,445	153,445	153,445	153,445	153,445	**1,841,338**
LaCrosse - Madison	Property Tax Expense	215,174	215,174	215,174	215,174	215,174	215,174	215,174	215,174	215,174	215,174	215,174	215,174	**2,582,083**
LaCrosse - Madison	OATT Credit													
LaCrosse - Madison	Total Revenue Requirement	1,677,736	1,660,488	1,640,045	1,637,392	1,633,668	1,629,921	1,626,171	1,622,454	1,613,562	1,605,469	1,602,925	1,599,629	**19,549,462**
LaCrosse - Madison	**Rider Revenue Requirement**	1,226,257	1,213,651	1,198,709	1,196,770	1,194,048	1,191,309	1,188,568	1,185,852	1,179,352	1,173,437	1,171,578	1,169,169	**14,288,700**
Total	CWIP Balance	71,969,355	73,720,535	76,767,272	48,404,968	51,834,414	51,413,766	53,509,871	55,904,932	57,904,889	59,829,143	63,404,524	19,866,277	**19,866,277**
Total	Plant In-Service	1,203,664,191	1,200,901,779	1,201,123,267	1,231,491,411	1,231,524,646	1,235,876,515	1,236,654,460	1,236,877,167	1,236,432,895	1,237,080,918	1,237,836,496	1,285,731,733	**1,285,731,733**
Total	Depreciation Reserve	138,610,969	140,934,463	143,255,036	145,704,401	148,282,394	150,877,742	153,492,912	156,111,483	158,731,261	161,353,116	163,979,293	166,653,984	**166,653,984**
Total	Accumulated Deferred Taxes	251,311,095	251,807,203	252,303,311	252,799,420	253,295,528	253,791,636	254,287,745	254,783,853	255,279,961	255,776,070	256,272,178	256,768,286	**256,768,286**
Total	Average Rate Base	885,310,771	883,548,011	881,858,366	881,614,320	881,338,793	881,952,966	882,254,234	881,887,165	880,858,608	879,805,664	880,137,158	881,334,590	**881,334,590**
Total	Tax Depreciation Expense	4,442,875	4,442,875	4,442,875	4,442,875	4,442,875	4,442,875	4,442,875	4,442,875	4,442,875	4,442,875	4,442,875	4,442,875	**244,624,792**
Total	CPI-TAX INTEREST	134,149	89,277	122,767	170,582	149,595	152,932	151,735	155,538	160,943	165,011	168,293	85,507	**1,706,332**
Total	Debt Return	1,659,958	1,656,653	1,653,484	1,653,027	1,652,510	1,653,662	1,654,227	1,653,538	1,651,610	1,649,636	1,650,257	1,652,502	**19,841,064**
Total	Equity Return	3,511,733	3,504,740	3,498,038	3,497,070	3,495,977	3,498,413	3,499,608	3,498,152	3,494,072	3,489,896	3,491,211	3,495,961	**41,974,873**
Total	Current Income Tax Requirement	816,519	794,902	804,529	875,373	918,349	927,678	935,673	937,991	939,013	939,806	943,404	931,496	**10,764,735**
Total	Book Depreciation	2,325,223	2,323,493	2,320,574	2,449,365	2,577,992	2,595,348	2,615,170	2,618,571	2,619,779	2,621,855	2,626,177	2,674,691	**30,368,238**
Total	AFUDC													
Total	Deferred Taxes	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	**5,953,300**
Total	Property Tax Expense	1,471,961	1,471,961	1,471,961	1,471,961	1,471,961	1,471,961	1,471,961	1,471,961	1,471,961	1,471,961	1,471,961	1,471,961	**17,663,530**
Total	OATT Credit	154,574	154,220	153,866	153,513	153,159	152,595	152,029	151,673	151,319	150,966	150,613	150,260	**1,828,786**
Total	Operating Expenses	91,229	349,642	(57,728)	162,068	122,843	90,366	634,365	626,647	642,378	785,523	714,990	770,802	**4,933,126**
Total	Total Revenue Requirement	8,099,950	10,402,710	10,400,327	9,024,911	10,651,012	11,810,798	11,128,421	10,960,962	10,744,518	10,183,976	10,201,603	10,595,020	**124,204,208**
Total	**Rider Revenue Requirement**	5,788,176	7,541,782	7,431,441	6,513,542	7,716,370	8,560,152	8,213,214	8,090,253	7,937,538	7,568,248	7,566,479	7,875,729	**90,802,924**

Project	Rider Components	Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022	2022
LaCrosse - Madison	CWIP Balance	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,185,012	1,190,165	1,190,165	1,190,165	**1,190,165**
LaCrosse - Madison	Plant In-Service	171,284,791	171,355,716	171,426,641	171,497,565	171,568,490	171,639,415	171,710,340	171,781,265	171,624,639	171,694,579	171,764,518	171,834,458	**171,834,458**
LaCrosse - Madison	Depreciation Reserve	14,040,167	14,410,165	14,780,166	15,150,169	15,520,174	15,890,181	16,260,191	16,630,204	16,999,946	17,369,418	17,738,889	18,108,360	**18,108,360**
LaCrosse - Madison	Accumulated Deferred Taxes	21,657,812	21,789,749	21,921,686	22,053,623	22,185,561	22,317,498	22,447,307	22,579,244	22,713,309	22,843,118	22,977,183	23,106,992	**23,106,992**
LaCrosse - Madison	Average Rate Base	136,832,924	136,490,350	136,059,339	135,628,325	135,197,308	134,766,290	134,337,397	133,906,373	133,359,580	132,819,398	132,388,378	131,959,037	**131,959,037**
LaCrosse - Madison	Tax Depreciation Expense	840,515	840,515	840,515	840,515	840,515	840,515	840,515	840,515	840,515	840,515	840,515	840,515	**10,086,179**
LaCrosse - Madison	CPI-TAX INTEREST													
LaCrosse - Madison	Debt Return	256,562	255,919	255,111	254,303	253,495	252,687	251,883	251,074	250,049	249,036	248,228	247,423	**3,025,771**
LaCrosse - Madison	Equity Return	542,771	541,412	539,702	537,992	536,283	534,573	532,872	531,162	528,993	526,850	525,141	523,438	**6,401,187**
LaCrosse - Madison	Current Income Tax Requirement	82,360	81,813	81,124	80,435	79,747	79,058	78,373	77,684	76,700	75,727	75,037	74,350	**942,407**
LaCrosse - Madison	Book Depreciation	369,996	369,998	370,001	370,003	370,005	370,008	370,010	370,012	369,742	369,471	369,471	369,471	**4,438,189**
LaCrosse - Madison	AFUDC													
LaCrosse - Madison	Deferred Taxes	131,937	131,937	131,937	131,937	131,937	131,937	131,937	131,937	131,937	131,937	131,937	131,937	**1,583,244**
LaCrosse - Madison	Property Tax Expense	211,345	211,345	211,345	211,345	211,345	211,345	211,345	211,345	211,345	211,345	211,345	211,345	**2,536,139**
LaCrosse - Madison	OATT Credit													
LaCrosse - Madison	Total Revenue Requirement	1,594,970	1,592,424	1,589,220	1,586,016	1,582,811	1,579,607	1,576,419	1,573,215	1,568,767	1,564,367	1,561,159	1,557,964	**18,926,938**
LaCrosse - Madison	**Rider Revenue Requirement**	1,166,722	1,164,859	1,162,516	1,160,172	1,157,828	1,155,484	1,153,152	1,150,808	1,147,554	1,144,336	1,141,989	1,139,652	**13,845,072**
Total	CWIP Balance	12,324,331	15,324,722	10,976,385	11,460,370	12,318,066	12,889,024	13,337,453	13,993,166	14,845,567	15,766,703	16,869,524	17,541,201	**17,541,201**
Total	Plant In-Service	1,300,331,854	1,306,674,001	1,318,845,197	1,324,852,128	1,330,568,981	1,337,645,291	1,343,596,327	1,349,287,212	1,354,743,127	1,360,660,024	1,367,201,071	1,373,728,815	**1,373,728,815**
Total	Depreciation Reserve	169,410,496	172,214,569	175,065,495	177,964,454	180,888,250	183,845,478	186,836,613	189,852,241	192,891,474	195,954,756	199,044,124	202,160,809	**202,160,809**
Total	Accumulated Deferred Taxes	257,307,095	257,896,003	258,484,910	259,073,817	259,662,724	260,251,631	260,831,039	261,419,947	262,018,352	262,597,761	263,196,166	263,775,575	**263,775,575**
Total	Average Rate Base	883,787,761	888,618,918	893,785,210	897,478,248	900,510,697	904,092,186	907,561,963	910,342,706	913,044,326	915,986,835	919,553,055	923,292,264	**923,292,264**
Total	Tax Depreciation Expense	5,058,096	5,058,096	5,058,096	5,058,096	5,058,096	5,058,096	5,058,096	5,058,096	5,058,096	5,058,096	5,058,096	5,058,096	**60,697,151**
Total	CPI-TAX INTEREST													
Total	Debt Return	1,657,102	1,666,160	1,675,847	1,682,772	1,688,458	1,695,173	1,701,679	1,706,893	1,711,958	1,717,475	1,724,162	1,731,173	**20,358,852**
Total	Equity Return	3,505,691	3,524,855	3,545,348	3,559,997	3,572,026	3,586,232	3,599,996	3,611,026	3,621,742	3,633,414	3,647,560	3,662,393	**43,070,282**
Total	Current Income Tax Requirement	723,215	750,128	777,292	802,575	817,445	836,660	855,888	870,216	884,060	898,468	914,695	931,696	**10,062,338**
Total	Book Depreciation	2,756,512	2,804,073	2,850,926	2,898,959	2,923,797	2,957,227	2,991,135	3,015,629	3,039,232	3,063,282	3,089,368	3,116,685	**35,506,824**
Total	AFUDC													
Total	Deferred Taxes	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	**7,066,885**
Total	Property Tax Expense	1,527,186	1,527,186	1,527,186	1,527,186	1,527,186	1,527,186	1,527,186	1,527,186	1,527,186	1,527,186	1,527,186	1,527,186	**18,326,232**
Total	OATT Credit	143,211	142,936	142,660	142,385	142,110	141,834	141,559	141,284	141,008	140,733	140,458	140,183	**1,700,361**
Total	Operating Expenses	805,786	805,786	805,786	805,786	805,786	805,786	805,786	805,786	805,786	805,786	805,786	805,786	**9,669,428**
Total	Total Revenue Requirement	9,738,487	9,916,954	10,392,279	10,602,509	10,660,274	11,393,180	11,496,597	11,377,185	11,186,050	10,598,641	10,762,187	11,102,607	**129,226,948**
Total	**Rider Revenue Requirement**	7,468,091	7,625,545	7,998,366	8,177,038	8,239,521	8,797,929	8,896,017	8,828,522	8,708,256	8,298,621	8,439,921	8,711,529	**100,189,358**

Project	Rider Components	Jan-23	Feb-23	Mar-23	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	2023
LaCrosse - Madison	CWIP Balance	1,190,165	1,190,165	1,190,165	1,190,165	1,190,165	1,190,165	1,190,165	1,190,165	1,190,165	1,190,165	1,190,165	1,190,165	**1,190,165**
LaCrosse - Madison	Plant In-Service	171,891,592	171,948,726	172,005,860	172,062,993	172,120,127	172,177,261	172,234,395	172,291,529	172,348,663	172,405,797	172,462,930	172,520,064	**172,520,064**
LaCrosse - Madison	Depreciation Reserve	18,477,832	18,847,303	19,216,775	19,586,246	19,955,717	20,325,189	20,694,660	21,064,131	21,433,603	21,803,074	22,172,546	22,542,017	**22,542,017**
LaCrosse - Madison	Accumulated Deferred Taxes	23,229,584	23,344,026	23,454,835	23,569,277	23,680,086	23,794,528	23,905,337	24,017,962	24,132,404	24,243,213	24,357,655	24,468,463	**24,468,463**
LaCrosse - Madison	Average Rate Base	131,530,510	131,103,731	130,680,584	130,253,805	129,830,658	129,403,879	128,980,733	128,555,770	128,128,990	127,705,844	127,279,064	126,855,918	**126,855,918**
LaCrosse - Madison	Tax Depreciation Expense	771,246	771,246	771,246	771,246	771,246	771,246	771,246	771,246	771,246	771,246	771,246	771,246	**9,254,948**
LaCrosse - Madison	CPI-TAX INTEREST													
LaCrosse - Madison	Debt Return	246,620	245,819	245,026	244,226	243,432	242,632	241,839	241,042	240,242	239,448	238,648	237,855	**2,906,830**
LaCrosse - Madison	Equity Return	521,738	520,045	518,366	516,673	514,995	513,302	511,624	509,938	508,245	506,567	504,874	503,195	**6,149,561**
LaCrosse - Madison	Current Income Tax Requirement	93,815	93,132	92,455	91,772	91,095	90,412	89,735	89,055	88,373	87,696	87,013	86,336	**1,080,890**
LaCrosse - Madison	Book Depreciation	369,471	369,471	369,471	369,471	369,471	369,471	369,471	369,471	369,471	369,471	369,471	369,471	**4,433,657**
LaCrosse - Madison	AFUDC													
LaCrosse - Madison	Deferred Taxes	112,625	112,625	112,625	112,625	112,625	112,625	112,625	112,625	112,625	112,625	112,625	112,625	**1,351,504**
LaCrosse - Madison	Property Tax Expense	212,330	212,330	212,330	212,330	212,330	212,330	212,330	212,330	212,330	212,330	212,330	212,330	**2,547,964**
LaCrosse - Madison	OATT Credit													
LaCrosse - Madison	Total Revenue Requirement	1,556,599	1,553,423	1,550,275	1,547,099	1,543,950	1,540,774	1,537,625	1,534,463	1,531,287	1,528,138	1,524,962	1,521,813	**18,470,406**
LaCrosse - Madison	**Rider Revenue Requirement**	1,136,754	1,134,435	1,132,136	1,129,816	1,127,517	1,125,197	1,122,898	1,120,588	1,118,269	1,115,969	1,113,650	1,111,350	**13,488,580**
Total	CWIP Balance	18,810,518	22,726,851	21,287,270	22,419,730	23,557,986	24,742,039	25,861,637	27,144,239	28,441,311	23,063,802	24,417,838	25,862,244	**25,862,244**
Total	Plant In-Service	1,382,609,488	1,391,229,329	1,402,930,169	1,411,766,095	1,420,356,850	1,428,966,336	1,437,804,653	1,446,396,963	1,454,984,874	1,471,015,534	1,477,460,330	1,486,569,619	**1,486,569,619**
Total	Depreciation Reserve	205,310,233	208,497,285	211,734,213	215,021,417	218,345,940	221,707,335	225,106,136	228,542,272	232,015,197	235,525,378	239,068,341	242,646,555	**242,646,555**
Total	Accumulated Deferred Taxes	264,337,548	264,879,392	265,404,035	265,945,879	266,470,522	267,012,366	267,537,009	268,070,253	268,612,097	269,136,740	269,678,584	270,203,227	**270,203,227**
Total	Average Rate Base	928,271,942	935,904,942	943,567,026	949,877,938	955,896,130	961,772,602	967,743,587	973,709,289	979,592,862	985,845,733	991,003,309	996,094,341	**996,094,341**
Total	Tax Depreciation Expense	5,276,115	5,276,115	5,276,115	5,276,115	5,276,115	5,276,115	5,276,115	5,276,115	5,276,115	5,276,115	5,276,115	5,276,115	**63,313,377**
Total	CPI-TAX INTEREST	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	1,272	518	2,026	**15,266**
Total	Debt Return	1,740,510	1,754,822	1,769,188	1,781,021	1,792,305	1,803,324	1,814,519	1,825,705	1,836,737	1,848,461	1,858,131	1,867,677	**21,692,399**
Total	Equity Return	3,682,145	3,712,423	3,742,816	3,767,849	3,791,721	3,815,031	3,838,716	3,862,380	3,885,718	3,910,521	3,930,980	3,951,174	**45,891,476**
Total	Current Income Tax Requirement	842,992	870,382	902,758	933,135	957,816	982,091	1,006,732	1,031,335	1,055,588	1,080,620	1,101,790	1,124,762	**11,890,000**
Total	Book Depreciation	3,149,424	3,187,052	3,236,928	3,287,205	3,324,522	3,361,395	3,398,802	3,436,136	3,472,924	3,510,181	3,542,963	3,578,214	**40,485,747**
Total	AFUDC													
Total	Deferred Taxes	533,244	533,244	533,244	533,244	533,244	533,244	533,244	533,244	533,244	533,244	533,244	533,244	**6,398,922**
Total	Property Tax Expense	1,531,935	1,531,935	1,531,935	1,531,935	1,531,935	1,531,935	1,531,935	1,531,935	1,531,935	1,531,935	1,531,935	1,531,935	**18,383,216**
Total	OATT Credit	139,904	139,628	139,353	139,077	138,801	138,525	138,250	137,974	137,698	137,422	137,146	136,871	**1,660,650**
Total	Operating Expenses	1,454,745	1,454,745	1,454,745	1,454,745	1,454,745	1,454,745	1,454,745	1,454,745	1,454,745	1,454,745	1,454,745	1,454,745	**17,456,943**
Total	Total Revenue Requirement	10,968,098	11,145,974	11,662,745	11,922,771	11,992,503	12,756,039	12,887,825	12,794,367	12,634,981	12,073,698	12,239,416	12,590,565	**145,668,982**
Total	**Rider Revenue Requirement**	8,762,637	8,924,611	9,336,288	9,559,308	9,640,436	10,227,771	10,354,118	10,315,925	10,229,160	9,849,540	9,996,867	10,279,728	**117,476,390**

Northern States Power Company
State of Minnesota
Transmission Cost Recovery (TCR) Rider
ADIT Prorate Calculation

			Jan - 2020	Feb - 2020	Mar - 2020	Apr - 2020	May - 2020	Jun - 2020	Jul - 2020	Aug - 2020	Sep - 2020	Oct - 2020	Nov - 2020	Dec - 2020
A	Pro-Rate Days				15	15	15	15	15	15	15	15	15	15
B	Pro-Rate Factor	A/# days in month			0.48387	0.50000	0.48387	0.50000	0.48387	0.48387	0.50000	0.48387	0.50000	0.48387
C	Deferred Beg Bal				244,624,792	245,268,247	245,911,702	246,555,157	247,198,612	247,842,067	248,485,522	249,128,977	249,772,432	250,415,887
D	Deferred Tax Exp Activity				643,455	643,455	643,455	643,455	643,455	643,455	643,455	643,455	643,455	643,455
E	Deferred Tax End Bal	(C+D)			245,268,247	245,911,702	246,555,157	247,198,612	247,842,067	248,485,522	249,128,977	249,772,432	250,415,887	251,059,342
F	Average ADIT End Bal	(C+E)/2			244,946,520	245,589,975	246,233,430	246,876,885	247,520,340	248,163,795	248,807,250	249,450,705	250,094,160	250,737,614
G	Deferred Tax Exp Prorated Activity	B*D			311,349	321,727	311,349	321,727	311,349	311,349	321,727	311,349	321,727	311,349
H	Deferred Tax End Bal Prorated	C+G			244,936,141	245,589,975	246,223,051	246,876,885	247,509,961	248,153,416	248,807,250	249,440,326	250,094,160	250,727,236
I	Revenue Requirement Factor	(WACC+(Equity Return*T/(1-T)))/12			0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%
J	RR of ADIT Pro-rate	(F-H)*I			77	-	77	-	77	77	-	77	-	77
K	Jurisdictional Allocator	Key Inputs			73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%	73.24%
L	MN Jur RR of ADIT Pro-rate	J*K			57	-	57	-	57	57	-	57	-	57

			Jan - 2021	Feb - 2021	Mar - 2021	Apr - 2021	May - 2021	Jun - 2021	Jul - 2021	Aug - 2021	Sep - 2021	Oct - 2021	Nov - 2021	Dec - 2021
A	Pro-Rate Days		15	14	15	15	15	15	15	15	15	15	15	15
B	Pro-Rate Factor	B = A/# days in month	0.50000	0.50000	0.50000	0.50000	0.50000	0.50000	0.50000	0.50000	0.50000	0.50000	0.50000	0.50000
C	Deferred Beg Bal		250,737,614	251,233,723	251,729,831	252,225,939	252,722,048	253,218,156	253,714,264	254,210,373	254,706,481	255,202,589	255,698,698	256,194,806
D	Deferred Tax Exp Activity		496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108	496,108
E	Deferred Tax End Bal	(C+D)	251,233,723	251,729,831	252,225,939	252,722,048	253,218,156	253,714,264	254,210,373	254,706,481	255,202,589	255,698,698	256,194,806	256,690,914
F	Average ADIT End Bal	(C+E)/2	250,985,669	251,481,777	251,977,885	252,473,994	252,970,102	253,466,210	253,962,319	254,458,427	254,954,535	255,450,644	255,946,752	256,442,860
G	Deferred Tax Exp Prorated Activity	B*D	248,054	248,054	248,054	248,054	248,054	248,054	248,054	248,054	248,054	248,054	248,054	248,054
H	Deferred Tax End Bal Prorated	C+G	250,985,669	251,481,777	251,977,885	252,473,994	252,970,102	253,466,210	253,962,319	254,458,427	254,954,535	255,450,644	255,946,752	256,442,860
I	Revenue Requirement Factor	(WACC+(Equity Return*T/(1-T)))/12	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%
J	RR of ADIT Pro-rate	(F-H)*I	(0)	-	(0)	-	(0)	-	(0)	-	(0)	-	(0)	-
K	Jurisdictional Allocator	Key Inputs	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%	73.09%
L	MN Jur RR of ADIT Pro-rate	J*K	(0)	-	(0)	-	(0)	-	(0)	-	(0)	-	(0)	-

			Jan - 2022	Feb - 2022	Mar - 2022	Apr - 2022	May - 2022	Jun - 2022	Jul - 2022	Aug - 2022	Sep - 2022	Oct - 2022	Nov - 2022	Dec - 2022
A	Pro-Rate Days		15	14	15	15	15	15	15	15	15	15	15	15
B	Pro-Rate Factor	B = A/# days in month	0.50000	0.50000	0.50000	0.50000	0.50000	0.50000	0.48387	0.48387	0.50000	0.48387	0.50000	0.48387
C	Deferred Beg Bal		256,442,860	257,031,767	257,620,674	258,209,582	258,798,489	259,387,396	259,976,303	260,565,210	261,154,117	261,743,024	262,331,931	262,920,838
D	Deferred Tax Exp Activity		588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907	588,907
E	Deferred Tax End Bal	(C+D)	257,031,767	257,620,674	258,209,582	258,798,489	259,387,396	259,976,303	260,565,210	261,154,117	261,743,024	262,331,931	262,920,838	263,509,745
F	Average ADIT End Bal	(C+E)/2	256,737,314	257,326,221	257,915,128	258,504,035	259,092,942	259,681,849	260,270,756	260,859,663	261,448,571	262,037,478	262,626,385	263,215,292
G	Deferred Tax Exp Prorated Activity	B*D	294,454	294,454	294,454	294,454	294,454	294,454	284,955	284,955	294,454	284,955	294,454	284,955
H	Deferred Tax End Bal Prorated	C+G	256,737,314	257,326,221	257,915,128	258,504,035	259,092,942	259,681,849	260,261,258	260,850,165	261,448,571	262,027,979	262,626,385	263,205,793
I	Revenue Requirement Factor	(WACC+(Equity Return*T/(1-T)))/12	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%	0.7442%
J	RR of ADIT Pro-rate	(F-H)*I	-	-	-	-	-	-	71	71	-	71	-	71
K	Jurisdictional Allocator	Key Inputs	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%	73.15%
L	MN Jur RR of ADIT Pro-rate	J*K	-	-	-	-	-	-	52	52	-	52	-	52

Redline

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax.

DETERMINATION OF TCR ADJUSTMENT FACTORS
A separate TCR Adjustment Factor shall be calculated for the following three customer groups: (1) Residential, (2) Commercial Non-Demand, and (3) Demand Billed. The TCR Adjustment Factor for each group shall be the value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW.

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the Commission. The TCR factor for each rate schedule is:

Residential	$0.00~~36075~~5783 per kWh	R
Commercial (Non-Demand)	$0.00~~31854~~4545 per kWh	R
Demand Billed	$~~0.982~~1.081 per kW	R

Recoverable Transmission and Distribution Costs shall be the annual revenue requirements for transmission and distribution costs associated with transmission projects and distribution planning and facilities eligible for recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account.

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period.

(Continued on Sheet No. 5-145)

Clean

APPLICATION
Applicable to bills for electric service provided under the Company's retail rate schedules.

RIDER
There shall be included on each customer's monthly bill a Transmission Cost Recovery (TCR) adjustment, which shall be the TCR Adjustment Factor multiplied by the customer's monthly billing energy or demand for electric service as described below. This TCR Adjustment shall be calculated before city surcharge and sales tax.

DETERMINATION OF TCR ADJUSTMENT FACTORS
A separate TCR Adjustment Factor shall be calculated for the following three customer groups: (1) Residential, (2) Commercial Non-Demand, and (3) Demand Billed. The TCR Adjustment Factor for each group shall be the value obtained by multiplying each group's weighting factor by the average retail cost per kWh. The average retail cost per kWh shall be determined by the forecasted balance of the TCR Tracker Account, divided by the forecasted retail sales for the calendar year. The Demand Billed customers' TCR Adjustment Factor is calculated similarly, but the resulting per kWh charge is converted to a per kW charge for application to billed kW rather than billed kWh. TCR Adjustment Factors shall be rounded to the nearest $0.000001 per kWh or $0.001 per kW.

The TCR Adjustment Factor for each customer group may be adjusted annually with approval of the Minnesota Public Utilities Commission (Commission). Each TCR Adjustment Factor shall apply to bills rendered subsequent to approval by the Commission. The TCR factor for each rate schedule is:

Residential	$0.005783 per kWh	R
Commercial (Non-Demand)	$0.004545 per kWh	R
Demand Billed	$1.081 per kW	R

Recoverable Transmission and Distribution Costs shall be the annual revenue requirements for transmission and distribution costs associated with transmission projects and distribution planning and facilities eligible for recovery under Minnesota Statute Sections 216B.1645 or 216B.16, subd. 7b that are determined by the Commission to be eligible for recovery under this Transmission Cost Recovery Rider. A standard model will be used to calculate the total forecasted revenue requirements for eligible projects for the designated period. All costs appropriately charged to the Transmission Tracker Account shall be eligible for recovery through this Rider, and all revenues recovered from the TCR Adjustment shall be credited to the Transmission Tracker Account.

Forecasted retail kWh sales and kW demands shall be those for the designated recovery period.

(Continued on Sheet No. 5-145)

CERTIFICATE OF SERVICE

I, Mustafa Adam, 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-21-___**
Xcel Energy Miscellaneous Electric Service List
E002/M-20-680
E002/M-21-694

Dated this 24th day of November 2021

/s/
____
Mustafa Adam
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
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	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Thomas	Tynes	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	GEN_SL_Northern States Power Company dba Xcel Energy-Elec_Xcel Miscl Electric

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_20-680_Official
David	Amster Olzweski	david@mysunshare.com	SunShare, LLC	1151 Bannock St Denver, CO 80204-8020	Electronic Service	No	OFF_SL_20-680_Official
Ellen	Anderson	ellena@umn.edu	325 Learning and Environmental Sciences	1954 Buford Ave Saint Paul, MN 55108	Electronic Service	No	OFF_SL_20-680_Official
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_20-680_Official
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Donna	Attanasio	dattanasio@law.gwu.edu	George Washington University	2000 H Street NW Washington, DC 20052	Electronic Service	No	OFF_SL_20-680_Official
John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance	1313 5th St SE Ste 303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_20-680_Official
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_20-680_Official
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services	3724 West Avera Drive PO Box 88920 Sioux Falls, SD 57109-8920	Electronic Service	No	OFF_SL_20-680_Official
William	Black	bblack@mmua.org	MMUA	Suite 200 3131 Fernbrook Lane North Plymouth, MN 55447	Electronic Service	No	OFF_SL_20-680_Official
Kenneth	Bradley	kbradley1965@gmail.com		2837 Emerson Ave S Apt CW112 Minneapolis, MN 55408	Electronic Service	No	OFF_SL_20-680_Official
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_20-680_Official
Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric	2411 W. Bridge St PO Box 485 Owatonna, MN 55060-0485	Electronic Service	No	OFF_SL_20-680_Official
Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company	215 South Cascade Street PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_20-680_Official
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_20-680_Official
Jason	Burwen	j.burwen@energystorage.org	Energy Storage Association	1155 15th St NW, Ste 500 Washington, DC 20005	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
LORI	CLOBES	lclobes@mienergy.coop	MiEnergy Cooperative	31110 COOPERATIVE WAY PO BOX 626 RUSHFORD, MN 55971	Electronic Service	No	OFF_SL_20-680_Official
Douglas M.	Carnival	dmc@mcgrannshea.com	McGrann Shea Carnival Straughn & Lamb	N/A	Electronic Service	No	OFF_SL_20-680_Official
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_20-680_Official
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_20-680_Official
Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC	26 Winton Road Meredith, NH 32535413	Electronic Service	No	OFF_SL_20-680_Official
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_20-680_Official
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_20-680_Official
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_20-680_Official
David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	OFF_SL_20-680_Official
Carlon	Doyle Fontaine	carlon.doyle.fontaine@senate.mn	MN Senate	75 Rev Dr Martin Luther King Jr Blvd Room G-17 St Paul, MN 55155	Electronic Service	No	OFF_SL_20-680_Official
Brian	Draxten	bhdraxten@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380498	Electronic Service	No	OFF_SL_20-680_Official
Brian	Edstrom	briane@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota St Ste W1360 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_20-680_Official
Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE	28477 N Lake Ave Frontenac, MN 55026-1044	Electronic Service	No	OFF_SL_20-680_Official
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Bob	Eleff	bob.eleff@house.mn	Regulated Industries Cmte	100 Rev Dr Martin Luther King Jr Blvd Room 600 St. Paul, MN 55155	Electronic Service	No	OFF_SL_20-680_Official
Betsy	Engelking	betsy@nationalgridrenewables.com	Geronimo Energy, LLC	8400 Normandale Lake Blvd Ste 1200 Bloomington, MN 55437	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Oncu	Er	oncu.er@avantenergy.com	Avant Energy, Agent for MMPA	220 S. Sixth St. Ste. 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
James C.	Erickson	jericksonkbc@gmail.com	Kelly Bay Consulting	17 Quechee St Superior, WI 54880-4421	Electronic Service	No	OFF_SL_20-680_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_20-680_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_20-680_Official
Lucas	Franco	lfranco@liunagroc.com	LIUNA	81 Little Canada Rd E Little Canada, MN 55117	Electronic Service	No	OFF_SL_20-680_Official
Nathan	Franzen	nathan@nationalgridrenewables.com	Geronimo Energy, LLC	8400 Normandale Lake Blvd Ste 1200 Bloomington, MN 55437	Electronic Service	No	OFF_SL_20-680_Official
Hal	Galvin	halgalvin@comcast.net	Provectus Energy Development llc	1936 Kenwood Parkway Minneapolis, MN 55405	Electronic Service	No	OFF_SL_20-680_Official
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_20-680_Official
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_20-680_Official
Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 220 Saint Paul, Minnesota 55102	Electronic Service	No	OFF_SL_20-680_Official
Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_20-680_Official
Timothy	Gulden	timothy.gulden@yahoo.com	Winona Renewable Energy, LLC	1449 Ridgewood Dr Winona, MN 55987	Electronic Service	No	OFF_SL_20-680_Official
Tony	Hainault	anthony.hainault@co.hennepin.mn.us	Hennepin County DES	701 4th Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	OFF_SL_20-680_Official
Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis	350 South 5th Street, Suite 315M Minneapolis, MN 55415	Electronic Service	No	OFF_SL_20-680_Official
Todd	Headlee	theadlee@dvigridsolutions.com	Dominion Voltage, Inc.	701 E. Cary Street Richmond, VA 23219	Electronic Service	No	OFF_SL_20-680_Official
Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec	414 Nicollet Mall, 401-7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_20-680_Official
Jared	Hendricks	jared.hendricks@owatonnautilities.com	Owatonna Municipal Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_20-680_Official
Shane	Henriksen	shane.henriksen@enbridge.com	Enbridge Energy Company, Inc.	1409 Hammond Ave FL 2 Superior, WI 54880	Electronic Service	No	OFF_SL_20-680_Official
Lynn	Hinkle	lynnh@ips-solar.com	IPS Solar	2670 Patton Rd Roseville, MN 55113	Electronic Service	No	OFF_SL_20-680_Official
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-680_Official
Jan	Hubbard	jan.hubbard@comcast.net		7730 Mississippi Lane Brooklyn Park, MN 55444	Electronic Service	No	OFF_SL_20-680_Official
Geoffrey	Inge	ginge@regintllc.com	Regulatory Intelligence LLC	PO Box 270636 Superior, CO 80027-9998	Electronic Service	No	OFF_SL_20-680_Official
Ralph	Jacobson	ralphj@ips-solar.com		2126 Roblyn Avenue Saint Paul, Minnesota 55104	Electronic Service	No	OFF_SL_20-680_Official
Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58501	Electronic Service	No	OFF_SL_20-680_Official
John S.	Jaffray	jjaffray@jjrpower.com	JJR Power	350 Highway 7 Suite 236 Excelsior, MN 55331	Electronic Service	No	OFF_SL_20-680_Official
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Nate	Jones	njones@hcpd.com	Heartland Consumers Power	PO Box 248 Madison, SD 57042	Electronic Service	No	OFF_SL_20-680_Official
Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC	260 Salem Church Road Sunfish Lake, Minnesota 55118	Electronic Service	No	OFF_SL_20-680_Official
Ted	Kjos	tkjos@mienergy.coop	MiEnergy Cooperative	31110 Cooperative Way PO Box 626 Rushford, MN 55971	Electronic Service	No	OFF_SL_20-680_Official
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_20-680_Official
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_20-680_Official
Chris	Kopel	chrisk@CMPASgroup.org	Central Minnesota Municipal Power Agency	459 S Grove St Blue Earth, MN 56013-2629	Electronic Service	No	OFF_SL_20-680_Official
Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative	PO Box 626 31110 Cooperative Way Rushford, MN 55971	Electronic Service	No	OFF_SL_20-680_Official
Michael	Krause	michaelkrause61@yahoo.com	Kandiyo Consulting, LLC	433 S 7th Street Suite 2025 Minneapolis, Minnesota 55415	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Krikava	mkrikava@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 S 8th St Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Matthew	Lacey	Mlacey@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_20-680_Official
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_20-680_Official
Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures	315 Manitoba Ave Wayzata, MN 55391	Electronic Service	No	OFF_SL_20-680_Official
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_20-680_Official
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_20-680_Official
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_20-680_Official
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Samuel	Mason	smason@beltramielectric.com	Beltrami Electric Cooperative, Inc.	4111 Technology Dr. NW PO Box 488 Bemidji, MN 56619-0488	Electronic Service	No	OFF_SL_20-680_Official
Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota	4237 24th Avenue S Minneapolis, MN 55406	Electronic Service	No	OFF_SL_20-680_Official
Dave	McNary	David.McNary@hennepin.us	Hennepin County DES	701 Fourth Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	OFF_SL_20-680_Official
Thomas	Melone	Thomas.Melone@AllcoUS.com	Minnesota Go Solar LLC	222 South 9th Street Suite 1600 Minneapolis, Minnesota 55120	Electronic Service	No	OFF_SL_20-680_Official
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Joseph	Meyer	joseph.meyer@ag.state.mn.us	Office of the Attorney General-RUD	Bremer Tower, Suite 1400 445 Minnesota Street St Paul, MN 55101-2131	Electronic Service	No	OFF_SL_20-680_Official
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_20-680_Official
Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency	123 2nd St W Thief River Falls, MN 56701	Electronic Service	No	OFF_SL_20-680_Official
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Ben	Nelson	benn@cmpasgroup.org	CMMPA	459 South Grove Street Blue Earth, MN 56013	Electronic Service	No	OFF_SL_20-680_Official
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Dale	Niezwaag	dniezwaag@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58503	Electronic Service	No	OFF_SL_20-680_Official
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_20-680_Official
Sephra	Ninow	sephra.ninow@energycenter.org	Center for Sustainable Energy	426 17th Street, Suite 700 Oakland, CA 94612	Electronic Service	No	OFF_SL_20-680_Official
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_20-680_Official
David	O'Brien	david.obrien@navigant.com	Navigant Consulting	77 South Bedford St Ste 400 Burlington, MA 01803	Electronic Service	No	OFF_SL_20-680_Official
Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello	505 Walnut Street Suite 1 Monticelllo, Minnesota 55362	Electronic Service	No	OFF_SL_20-680_Official
Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District	PO Box 248 Madison, SD 570420248	Electronic Service	No	OFF_SL_20-680_Official
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_20-680_Official
Dan	Patry	dpatry@sunedison.com	SunEdison	600 Clipper Drive Belmont, CA 94002	Electronic Service	No	OFF_SL_20-680_Official
Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_20-680_Official
Mary Beth	Peranteau	mperanteau@wheelerlaw.com	Wheeler Van Sickle & Anderson SC	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	OFF_SL_20-680_Official
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute	1000 Vermont Ave, Third Floor Washington, DC 20005	Electronic Service	No	OFF_SL_20-680_Official
David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_20-680_Official
Gregory	Randa	granda@lakecountrypower.com	Lake Country Power	26039 Bear Ridge Drive Cohasset, MN 55721	Electronic Service	No	OFF_SL_20-680_Official
Mark	Rathbun	mrathbun@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_20-680_Official
Michael	Reinertson	michael.reinertson@avantenergy.com	Avant Energy	220 S. Sixth St. Ste 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_20-680_Official
John C.	Reinhardt	N/A	Laura A. Reinhardt	3552 26th Ave S Minneapolis, MN 55406	Paper Service	No	OFF_SL_20-680_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_20-680_Official
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_20-680_Official
Isabel	Ricker	ricker@fresh-energy.org	Fresh Energy	408 Saint Peter Street Suite 220 Saint Paul, MN 55102	Electronic Service	No	OFF_SL_20-680_Official
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative	P.O. Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_20-680_Official
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_20-680_Official
Thomas	Scharff	thomas.scharff@versoco.com	Verso Corp	600 High Street Wisconsin Rapids, WI 54495	Electronic Service	No	OFF_SL_20-680_Official
Christopher	Schoenherr	cp.schoenherr@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_20-680_Official
Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_20-680_Official
Dean	Sedgwick	Sedgwick@Itascapower.com	Itasca Power Company	PO Box 455 Spring Lake, MN 56680	Electronic Service	No	OFF_SL_20-680_Official
Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology	120 Tredegar Street Richmond, Virginia 23219	Electronic Service	No	OFF_SL_20-680_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_20-680_Official
Janet	Shaddix Elling	jshaddix@janetshaddix.com	Shaddix And Associates	7400 Lyndale Ave S Ste 190 Richfield, MN 55423	Electronic Service	Yes	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Patricia F	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.	180 N LaSalle St Ste 3700 Chicago, IL 60601	Electronic Service	No	OFF_SL_20-680_Official
Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	OFF_SL_20-680_Official
Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	OFF_SL_20-680_Official
Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.	254 E Hacienda Ave Campbell, CA 95008	Electronic Service	No	OFF_SL_20-680_Official
Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_20-680_Official
Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy	305 Saint Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_20-680_Official
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_20-680_Official
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	No	OFF_SL_20-680_Official
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	OFF_SL_20-680_Official
Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Tom	Stanton	tstanton@nrri.org	NRRI	1080 Carmack Road Columbus, OH 43210	Electronic Service	No	OFF_SL_20-680_Official
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_20-680_Official
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_20-680_Official
Peter	Teigland	pteigland@mnseia.org	Minnesota Solar Energy Industries Association	2288 University Ave W Saint Paul, MN 55114	Electronic Service	No	OFF_SL_20-680_Official
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_20-680_Official
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_20-680_Official
Lise	Trudeau	lise.trudeau@state.mn.us	Department of Commerce	85 7th Place East Suite 500 Saint Paul, MN 55101	Electronic Service	No	OFF_SL_20-680_Official
Karen	Turnboom	karen.turnboom@versoco.com	Verso Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thomas	Tynes	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	OFF_SL_20-680_Official
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_20-680_Official
Curt	Volkmann	curt@newenergy-advisors.com	Fresh Energy	408 St Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_20-680_Official
Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities	208 S Walnut Ave PO BOX 800 Owatonna, MN 55060	Electronic Service	No	OFF_SL_20-680_Official
Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802-2093	Electronic Service	No	OFF_SL_20-680_Official
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_20-680_Official
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_20-680_Official
Yochi	Zakai	yzakai@smwlaw.com	SHUTE, MIHALY & WEINBERGER LLP	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Thomas J.	Zaremba	TZaremba@wheelerlaw.com	WHEELER, VAN SICKLE & ANDERSON	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	OFF_SL_20-680_Official
Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC	W234 N2000 Ridgeview Pkwy Court Waukesha, WI 53188-1022	Electronic Service	No	OFF_SL_20-680_Official
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_20-680_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael	Allen	michael.allen@allenergysolar.com	All Energy Solar	721 W 26th st Suite 211 Minneapolis, Minnesota 55405	Electronic Service	No	OFF_SL_21-694_M-21-694
David	Amster Olzweski	david@mysunshare.com	SunShare, LLC	1151 Bannock St Denver, CO 80204-8020	Electronic Service	No	OFF_SL_21-694_M-21-694
Ellen	Anderson	ellena@umn.edu	325 Learning and Environmental Sciences	1954 Buford Ave Saint Paul, MN 55108	Electronic Service	No	OFF_SL_21-694_M-21-694
Alison C	Archer	aarcher@misoenergy.org	MISO	2985 Ames Crossing Rd Eagan, MN 55121	Electronic Service	No	OFF_SL_21-694_M-21-694
Mara	Ascheman	mara.k.ascheman@xcelenergy.com	Xcel Energy	414 Nicollet Mall Fl 5 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Donna	Attanasio	dattanasio@law.gwu.edu	George Washington University	2000 H Street NW Washington, DC 20052	Electronic Service	No	OFF_SL_21-694_M-21-694
John	Bailey	bailey@ilsr.org	Institute For Local Self-Reliance	1313 5th St SE Ste 303 Minneapolis, MN 55414	Electronic Service	No	OFF_SL_21-694_M-21-694
Gail	Baranko	gail.baranko@xcelenergy.com	Xcel Energy	414 Nicollet Mall7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Jessica L	Bayles	Jessica.Bayles@stoel.com	Stoel Rives LLP	1150 18th St NW Ste 325 Washington, DC 20036	Electronic Service	No	OFF_SL_21-694_M-21-694
James J.	Bertrand	james.bertrand@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Derek	Bertsch	derek.bertsch@mrenergy.com	Missouri River Energy Services	3724 West Avera Drive PO Box 88920 Sioux Falls, SD 57109-8920	Electronic Service	No	OFF_SL_21-694_M-21-694
William	Black	bblack@mmua.org	MMUA	Suite 200 3131 Fernbrook Lane North Plymouth, MN 55447	Electronic Service	No	OFF_SL_21-694_M-21-694
Kenneth	Bradley	kbradley1965@gmail.com		2837 Emerson Ave S Apt CW112 Minneapolis, MN 55408	Electronic Service	No	OFF_SL_21-694_M-21-694
Elizabeth	Brama	ebrama@taftlaw.com	Taft Stettinius & Hollister LLP	2200 IDS Center 80 South 8th Street Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Jon	Brekke	jbrekke@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_21-694_M-21-694
Sydney R.	Briggs	sbriggs@swce.coop	Steele-Waseca Cooperative Electric	2411 W. Bridge St PO Box 485 Owatonna, MN 55060-0485	Electronic Service	No	OFF_SL_21-694_M-21-694
Mark B.	Bring	mbring@otpco.com	Otter Tail Power Company	215 South Cascade Street PO Box 496 Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_21-694_M-21-694
Christina	Brusven	cbrusven@fredlaw.com	Fredrikson Byron	200 S 6th St Ste 4000 Minneapolis, MN 554021425	Electronic Service	No	OFF_SL_21-694_M-21-694
Jason	Burwen	j.burwen@energystorage.org	Energy Storage Association	1155 15th St NW, Ste 500 Washington, DC 20005	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
LORI	CLOBES	lclobes@mienergy.coop	MiEnergy Cooperative	31110 COOPERATIVE WAY PO BOX 626 RUSHFORD, MN 55971	Electronic Service	No	OFF_SL_21-694_M-21-694
James	Canaday	james.canaday@ag.state.mn.us	Office of the Attorney General-RUD	Suite 1400 445 Minnesota St. St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-694_M-21-694
Douglas M.	Carnival	dmc@mcgrannshea.com	McGrann Shea Carnival Straughn & Lamb	N/A	Electronic Service	No	OFF_SL_21-694_M-21-694
Ray	Choquette	rchoquette@agp.com	Ag Processing Inc.	12700 West Dodge Road PO Box 2047 Omaha, NE 68103-2047	Electronic Service	No	OFF_SL_21-694_M-21-694
John	Coffman	john@johncoffman.net	AARP	871 Tuxedo Blvd. St, Louis, MO 63119-2044	Electronic Service	No	OFF_SL_21-694_M-21-694
Kenneth A.	Colburn	kcolburn@symbioticstrategies.com	Symbiotic Strategies, LLC	26 Winton Road Meredith, NH 32535413	Electronic Service	No	OFF_SL_21-694_M-21-694
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_21-694_M-21-694
Riley	Conlin	riley.conlin@stoel.com	Stoel Rives LLP	33 S. 6th Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Brooke	Cooper	bcooper@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022191	Electronic Service	No	OFF_SL_21-694_M-21-694
George	Crocker	gwillc@nawo.org	North American Water Office	PO Box 174 Lake Elmo, MN 55042	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_21-694_M-21-694
James	Denniston	james.r.denniston@xcelenergy.com	Xcel Energy Services, Inc.	414 Nicollet Mall, 401-8 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Curt	Dieren	curt.dieren@dgr.com	L&O Power Cooperative	1302 S Union St Rock Rapids, IA 51246	Electronic Service	No	OFF_SL_21-694_M-21-694
Carlon	Doyle Fontaine	carlon.doyle.fontaine@senate.mn	MN Senate	75 Rev Dr Martin Luther King Jr Blvd Room G-17 St Paul, MN 55155	Electronic Service	No	OFF_SL_21-694_M-21-694
Brian	Draxten	bhdraxten@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380498	Electronic Service	No	OFF_SL_21-694_M-21-694
Kristen	Eide Tollefson	healingsystems69@gmail.com	R-CURE	28477 N Lake Ave Frontenac, MN 55026-1044	Electronic Service	No	OFF_SL_21-694_M-21-694
Rebecca	Eilers	rebecca.d.eilers@xcelenergy.com	Xcel Energy	414 Nicollet Mall - 401 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Bob	Eleff	bob.eleff@house.mn	Regulated Industries Cmte	100 Rev Dr Martin Luther King Jr Blvd Room 600 St. Paul, MN 55155	Electronic Service	No	OFF_SL_21-694_M-21-694
Betsy	Engelking	betsy@nationalgridrenewables.com	Geronimo Energy, LLC	8400 Normandale Lake Blvd Ste 1200 Bloomington, MN 55437	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Oncu	Er	oncu.er@avantenergy.com	Avant Energy, Agent for MMPA	220 S. Sixth St. Ste. 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
James C.	Erickson	jericksonkbc@gmail.com	Kelly Bay Consulting	17 Quechee St Superior, WI 54880-4421	Electronic Service	No	OFF_SL_21-694_M-21-694
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-694_M-21-694
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_21-694_M-21-694
Nathan	Franzen	nathan@nationalgridrenewables.com	Geronimo Energy, LLC	8400 Normandale Lake Blvd Ste 1200 Bloomington, MN 55437	Electronic Service	No	OFF_SL_21-694_M-21-694
Hal	Galvin	halgalvin@comcast.net	Provectus Energy Development llc	1936 Kenwood Parkway Minneapolis, MN 55405	Electronic Service	No	OFF_SL_21-694_M-21-694
Edward	Garvey	garveyed@aol.com	Residence	32 Lawton St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-694_M-21-694
Edward	Garvey	edward.garvey@AESLconsulting.com	AESL Consulting	32 Lawton St Saint Paul, MN 55102-2617	Electronic Service	No	OFF_SL_21-694_M-21-694
Bruce	Gerhardson	bgerhardson@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Allen	Gleckner	gleckner@fresh-energy.org	Fresh Energy	408 St. Peter Street Ste 220 Saint Paul, Minnesota 55102	Electronic Service	No	OFF_SL_21-694_M-21-694
Jenny	Glumack	jenny@mrea.org	Minnesota Rural Electric Association	11640 73rd Ave N Maple Grove, MN 55369	Electronic Service	No	OFF_SL_21-694_M-21-694
Timothy	Gulden	timothy.gulden@yahoo.com	Winona Renewable Energy, LLC	1449 Ridgewood Dr Winona, MN 55987	Electronic Service	No	OFF_SL_21-694_M-21-694
Tony	Hainault	anthony.hainault@co.hennepin.mn.us	Hennepin County DES	701 4th Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	OFF_SL_21-694_M-21-694
Kim	Havey	kim.havey@minneapolismn.gov	City of Minneapolis	350 South 5th Street, Suite 315M Minneapolis, MN 55415	Electronic Service	No	OFF_SL_21-694_M-21-694
Todd	Headlee	theadlee@dvigridsolutions.com	Dominion Voltage, Inc.	701 E. Cary Street Richmond, VA 23219	Electronic Service	No	OFF_SL_21-694_M-21-694
Amber	Hedlund	amber.r.hedlund@xcelenergy.com	Northern States Power Company dba Xcel Energy-Elec	414 Nicollet Mall, 401-7 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Adam	Heinen	aheinen@dakotaelectric.com	Dakota Electric Association	4300 220th St W Farmington, MN 55024	Electronic Service	No	OFF_SL_21-694_M-21-694
Jared	Hendricks	jared.hendricks@owatonnautilities.com	Owatonna Municipal Public Utilities	PO Box 800 208 S Walnut Ave Owatonna, MN 55060-2940	Electronic Service	No	OFF_SL_21-694_M-21-694
Annete	Henkel	mui@mnutilityinvestors.org	Minnesota Utility Investors	413 Wacouta Street #230 St.Paul, MN 55101	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Shane	Henriksen	shane.henriksen@enbridge.com	Enbridge Energy Company, Inc.	1409 Hammond Ave FL 2 Superior, WI 54880	Electronic Service	No	OFF_SL_21-694_M-21-694
Lynn	Hinkle	lynnh@ips-solar.com	IPS Solar	2670 Patton Rd Roseville, MN 55113	Electronic Service	No	OFF_SL_21-694_M-21-694
Michael	Hoppe	lu23@ibew23.org	Local Union 23, I.B.E.W.	445 Etna Street Ste. 61 St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-694_M-21-694
Jan	Hubbard	jan.hubbard@comcast.net		7730 Mississippi Lane Brooklyn Park, MN 55444	Electronic Service	No	OFF_SL_21-694_M-21-694
Geoffrey	Inge	ginge@regintllc.com	Regulatory Intelligence LLC	PO Box 270636 Superior, CO 80027-9998	Electronic Service	No	OFF_SL_21-694_M-21-694
Ralph	Jacobson	ralphj@ips-solar.com		2126 Roblyn Avenue Saint Paul, Minnesota 55104	Electronic Service	No	OFF_SL_21-694_M-21-694
Casey	Jacobson	cjacobson@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58501	Electronic Service	No	OFF_SL_21-694_M-21-694
John S.	Jaffray	jjaffray@jjrpower.com	JJR Power	350 Highway 7 Suite 236 Excelsior, MN 55331	Electronic Service	No	OFF_SL_21-694_M-21-694
Alan	Jenkins	aj@jenkinsatlaw.com	Jenkins at Law	2950 Yellowtail Ave. Marathon, FL 33050	Electronic Service	No	OFF_SL_21-694_M-21-694
Richard	Johnson	Rick.Johnson@lawmoss.com	Moss & Barnett	150 S. 5th Street Suite 1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Sarah	Johnson Phillips	sarah.phillips@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Nate	Jones	njones@hcpd.com	Heartland Consumers Power	PO Box 248 Madison, SD 57042	Electronic Service	No	OFF_SL_21-694_M-21-694
Michael	Kampmeyer	mkampmeyer@a-e-group.com	AEG Group, LLC	260 Salem Church Road Sunfish Lake, Minnesota 55118	Electronic Service	No	OFF_SL_21-694_M-21-694
Ted	Kjos	tkjos@mienergy.coop	MiEnergy Cooperative	31110 Cooperative Way PO Box 626 Rushford, MN 55971	Electronic Service	No	OFF_SL_21-694_M-21-694
Brad	Klein	bklein@elpc.org	Environmental Law & Policy Center	35 E. Wacker Drive, Suite 1600 Suite 1600 Chicago, IL 60601	Electronic Service	No	OFF_SL_21-694_M-21-694
Thomas	Koehler	TGK@IBEW160.org	Local Union #160, IBEW	2909 Anthony Ln St Anthony Village, MN 55418-3238	Electronic Service	No	OFF_SL_21-694_M-21-694
Chris	Kopel	chrisk@CMPASgroup.org	Central Minnesota Municipal Power Agency	459 S Grove St Blue Earth, MN 56013-2629	Electronic Service	No	OFF_SL_21-694_M-21-694
Brian	Krambeer	bkrambeer@mienergy.coop	MiEnergy Cooperative	PO Box 626 31110 Cooperative Way Rushford, MN 55971	Electronic Service	No	OFF_SL_21-694_M-21-694
Michael	Krause	michaelkrause61@yahoo.com	Kandiyo Consulting, LLC	433 S 7th Street Suite 2025 Minneapolis, Minnesota 55415	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Matthew	Lacey	Mlacey@grenergy.com	Great River Energy	12300 Elm Creek Boulevard Maple Grove, MN 553694718	Electronic Service	No	OFF_SL_21-694_M-21-694
Carmel	Laney	carmel.laney@stoel.com	Stoel Rives LLP	33 South Sixth Street Suite 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Peder	Larson	plarson@larkinhoffman.com	Larkin Hoffman Daly & Lindgren, Ltd.	8300 Norman Center Drive Suite 1000 Bloomington, MN 55437	Electronic Service	No	OFF_SL_21-694_M-21-694
James D.	Larson	james.larson@avantenergy.com	Avant Energy Services	220 S 6th St Ste 1300 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Dean	Leischow	dean@sunrisenrg.com	Sunrise Energy Ventures	315 Manitoba Ave Wayzata, MN 55391	Electronic Service	No	OFF_SL_21-694_M-21-694
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-694_M-21-694
Ryan	Long	ryan.j.long@xcelenergy.com	Xcel Energy	414 Nicollet Mall 401 8th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Susan	Ludwig	sludwig@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_21-694_M-21-694
Kavita	Maini	kmaini@wi.rr.com	KM Energy Consulting, LLC	961 N Lost Woods Rd Oconomowoc, WI 53066	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Pam	Marshall	pam@energycents.org	Energy CENTS Coalition	823 7th St E St. Paul, MN 55106	Electronic Service	No	OFF_SL_21-694_M-21-694
Mary	Martinka	mary.a.martinka@xcelenergy.com	Xcel Energy Inc	414 Nicollet Mall 7th Floor Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Samuel	Mason	smason@beltramielectric.com	Beltrami Electric Cooperative, Inc.	4111 Technology Dr. NW PO Box 488 Bemidji, MN 56619-0488	Electronic Service	No	OFF_SL_21-694_M-21-694
Gregg	Mast	gmast@cleanenergyeconomymn.org	Clean Energy Economy Minnesota	4237 24th Avenue S Minneapolis, MN 55406	Electronic Service	No	OFF_SL_21-694_M-21-694
Dave	McNary	David.McNary@hennepin.us	Hennepin County DES	701 Fourth Ave S Ste 700 Minneapolis, MN 55415-1842	Electronic Service	No	OFF_SL_21-694_M-21-694
Thomas	Melone	Thomas.Melone@AllcoUS.com	Minnesota Go Solar LLC	222 South 9th Street Suite 1600 Minneapolis, Minnesota 55120	Electronic Service	No	OFF_SL_21-694_M-21-694
Brian	Meloy	brian.meloy@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Stacy	Miller	stacy.miller@minneapolismn.gov	City of Minneapolis	350 S. 5th Street Room M 301 Minneapolis, MN 55415	Electronic Service	No	OFF_SL_21-694_M-21-694
David	Moeller	dmoeller@allete.com	Minnesota Power	30 W Superior St Duluth, MN 558022093	Electronic Service	No	OFF_SL_21-694_M-21-694
Dalene	Monsebroten	dalene.monsebroten@nmpagency.com	Northern Municipal Power Agency	123 2nd St W Thief River Falls, MN 56701	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Andrew	Moratzka	andrew.moratzka@stoel.com	Stoel Rives LLP	33 South Sixth St Ste 4200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Carl	Nelson	cnelson@mncee.org	Center for Energy and Environment	212 3rd Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Ben	Nelson	benn@cmpasgroup.org	CMMPA	459 South Grove Street Blue Earth, MN 56013	Electronic Service	No	OFF_SL_21-694_M-21-694
Dale	Niezwaag	dniezwaag@bepc.com	Basin Electric Power Cooperative	1717 East Interstate Avenue Bismarck, ND 58503	Electronic Service	No	OFF_SL_21-694_M-21-694
David	Niles	david.niles@avantenergy.com	Minnesota Municipal Power Agency	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Sephra	Ninow	sephra.ninow@energycenter.org	Center for Sustainable Energy	426 17th Street, Suite 700 Oakland, CA 94612	Electronic Service	No	OFF_SL_21-694_M-21-694
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_21-694_M-21-694
Samantha	Norris	samanthanorris@alliantenergy.com	Interstate Power and Light Company	200 1st Street SE PO Box 351 Cedar Rapids, IA 524060351	Electronic Service	No	OFF_SL_21-694_M-21-694
David	O'Brien	david.obrien@navigant.com	Navigant Consulting	77 South Bedford St Ste 400 Burlington, MA 01803	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Jeff	O'Neill	jeff.oneill@ci.monticello.mn.us	City of Monticello	505 Walnut Street Suite 1 Monticelllo, Minnesota 55362	Electronic Service	No	OFF_SL_21-694_M-21-694
Russell	Olson	rolson@hcpd.com	Heartland Consumers Power District	PO Box 248 Madison, SD 570420248	Electronic Service	No	OFF_SL_21-694_M-21-694
Carol A.	Overland	overland@legalectric.org	Legalectric - Overland Law Office	1110 West Avenue Red Wing, MN 55066	Electronic Service	No	OFF_SL_21-694_M-21-694
Dan	Patry	dpatry@sunedison.com	SunEdison	600 Clipper Drive Belmont, CA 94002	Electronic Service	No	OFF_SL_21-694_M-21-694
Jeffrey C	Paulson	jeff.jcplaw@comcast.net	Paulson Law Office, Ltd.	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_21-694_M-21-694
Mary Beth	Peranteau	mperanteau@wheelerlaw.com	Wheeler Van Sickle & Anderson SC	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	OFF_SL_21-694_M-21-694
Jennifer	Peterson	jjpeterson@mnpower.com	Minnesota Power	30 West Superior Street Duluth, MN 55802	Electronic Service	No	OFF_SL_21-694_M-21-694
Hannah	Polikov	hpolikov@aee.net	Advanced Energy Economy Institute	1000 Vermont Ave, Third Floor Washington, DC 20005	Electronic Service	No	OFF_SL_21-694_M-21-694
David G.	Prazak	dprazak@otpco.com	Otter Tail Power Company	P.O. Box 496 215 South Cascade Street Fergus Falls, MN 565380496	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Gregory	Randa	granda@lakecountrypower.com	Lake Country Power	26039 Bear Ridge Drive Cohasset, MN 55721	Electronic Service	No	OFF_SL_21-694_M-21-694
Mark	Rathbun	mrathbun@grenergy.com	Great River Energy	12300 Elm Creek Blvd Maple Grove, MN 55369	Electronic Service	No	OFF_SL_21-694_M-21-694
Michael	Reinertson	michael.reinertson@avantenergy.com	Avant Energy	220 S. Sixth St. Ste 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
John C.	Reinhardt	N/A	Laura A. Reinhardt	3552 26th Ave S Minneapolis, MN 55406	Paper Service	No	OFF_SL_21-694_M-21-694
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_21-694_M-21-694
Kevin	Reuther	kreuther@mncenter.org	MN Center for Environmental Advocacy	26 E Exchange St, Ste 206 St. Paul, MN 551011667	Electronic Service	No	OFF_SL_21-694_M-21-694
Isabel	Ricker	ricker@fresh-energy.org	Fresh Energy	408 Saint Peter Street Suite 220 Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-694_M-21-694
Amanda	Rome	amanda.rome@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 5 Minneapoli, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Robert K.	Sahr	bsahr@eastriver.coop	East River Electric Power Cooperative	P.O. Box 227 Madison, SD 57042	Electronic Service	No	OFF_SL_21-694_M-21-694
Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Richard	Savelkoul	rsavelkoul@martinsquires.com	Martin & Squires, P.A.	332 Minnesota Street Ste W2750 St. Paul, MN 55101	Electronic Service	No	OFF_SL_21-694_M-21-694
Thomas	Scharff	thomas.scharff@versoco.com	Verso Corp	600 High Street Wisconsin Rapids, WI 54495	Electronic Service	No	OFF_SL_21-694_M-21-694
Christopher	Schoenherr	cp.schoenherr@smmpa.org	SMMPA	500 First Ave SW Rochester, MN 55902-3303	Electronic Service	No	OFF_SL_21-694_M-21-694
Kay	Schraeder	kschraeder@minnkota.com	Minnkota Power	5301 32nd Ave S Grand Forks, ND 58201	Electronic Service	No	OFF_SL_21-694_M-21-694
Dean	Sedgwick	Sedgwick@Itascapower.com	Itasca Power Company	PO Box 455 Spring Lake, MN 56680	Electronic Service	No	OFF_SL_21-694_M-21-694
Maria	Seidler	maria.seidler@dom.com	Dominion Energy Technology	120 Tredegar Street Richmond, Virginia 23219	Electronic Service	No	OFF_SL_21-694_M-21-694
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_21-694_M-21-694
Patricia F	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.	180 N LaSalle St Ste 3700 Chicago, IL 60601	Electronic Service	No	OFF_SL_21-694_M-21-694
Bria	Shea	bria.e.shea@xcelenergy.com	Xcel Energy	414 Nicollet Mall Minneapolis, MN 55401	Electronic Service	No	OFF_SL_21-694_M-21-694
Doug	Shoemaker	dougs@charter.net	Minnesota Renewable Energy	2928 5th Ave S Minneapolis, MN 55408	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Anne	Smart	anne.smart@chargepoint.com	ChargePoint, Inc.	254 E Hacienda Ave Campbell, CA 95008	Electronic Service	No	OFF_SL_21-694_M-21-694
Ken	Smith	ken.smith@districtenergy.com	District Energy St. Paul Inc.	76 W Kellogg Blvd St. Paul, MN 55102	Electronic Service	No	OFF_SL_21-694_M-21-694
Ken	Smith	ken.smith@ever-greenenergy.com	Ever Green Energy	305 Saint Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-694_M-21-694
Trevor	Smith	trevor.smith@avantenergy.com	Avant Energy, Inc.	220 South Sixth Street Suite 1300 Minneapolis, Minnesota 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Joshua	Smith	joshua.smith@sierraclub.org		85 Second St FL 2 San Francisco, California 94105	Electronic Service	No	OFF_SL_21-694_M-21-694
Beth H.	Soholt	bsoholt@windonthewires.org	Wind on the Wires	570 Asbury Street Suite 201 St. Paul, MN 55104	Electronic Service	No	OFF_SL_21-694_M-21-694
Sky	Stanfield	stanfield@smwlaw.com	Shute, Mihaly & Weinberger	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_21-694_M-21-694
Tom	Stanton	tstanton@nrri.org	NRRI	1080 Carmack Road Columbus, OH 43210	Electronic Service	No	OFF_SL_21-694_M-21-694
Byron E.	Starns	byron.starns@stinson.com	STINSON LLP	50 S 6th St Ste 2600 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Eric	Swanson	eswanson@winthrop.com	Winthrop & Weinstine	225 S 6th St Ste 3500 Capella Tower Minneapolis, MN 554024629	Electronic Service	No	OFF_SL_21-694_M-21-694
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	Yes	OFF_SL_21-694_M-21-694
Peter	Teigland	pteigland@mnseia.org	Minnesota Solar Energy Industries Association	2288 University Ave W Saint Paul, MN 55114	Electronic Service	No	OFF_SL_21-694_M-21-694
Stuart	Tommerdahl	stommerdahl@otpco.com	Otter Tail Power Company	215 S Cascade St PO Box 496 Fergus Falls, MN 56537	Electronic Service	No	OFF_SL_21-694_M-21-694
Pat	Treseler	pat.jcplaw@comcast.net	Paulson Law Office LTD	4445 W 77th Street Suite 224 Edina, MN 55435	Electronic Service	No	OFF_SL_21-694_M-21-694
Karen	Turnboom	karen.turnboom@versoco.com	Verso Corporation	100 Central Avenue Duluth, MN 55807	Electronic Service	No	OFF_SL_21-694_M-21-694
Thomas	Tynes	jjazynka@energyfreedomcoalition.com	Energy Freedom Coalition of America	101 Constitution Ave NW Ste 525 East Washington, DC 20001	Electronic Service	No	OFF_SL_21-694_M-21-694
Lisa	Veith	lisa.veith@ci.stpaul.mn.us	City of St. Paul	400 City Hall and Courthouse 15 West Kellogg Blvd. St. Paul, MN 55102	Electronic Service	No	OFF_SL_21-694_M-21-694
Curt	Volkmann	curt@newenergy-advisors.com	Fresh Energy	408 St Peter St Saint Paul, MN 55102	Electronic Service	No	OFF_SL_21-694_M-21-694

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Roger	Warehime	roger.warehime@owatonnautilities.com	Owatonna Municipal Public Utilities	208 S Walnut Ave PO BOX 800 Owatonna, MN 55060	Electronic Service	No	OFF_SL_21-694_M-21-694
Jenna	Warmuth	jwarmuth@mnpower.com	Minnesota Power	30 W Superior St Duluth, MN 55802-2093	Electronic Service	No	OFF_SL_21-694_M-21-694
Samantha	Williams	swilliams@nrdc.org	Natural Resources Defense Council	20 N. Wacker Drive Ste 1600 Chicago, IL 60606	Electronic Service	No	OFF_SL_21-694_M-21-694
Joseph	Windler	jwindler@winthrop.com	Winthrop & Weinstine	225 South Sixth Street, Suite 3500 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694
Robyn	Woeste	robynwoeste@alliantenergy.com	Interstate Power and Light Company	200 First St SE Cedar Rapids, IA 52401	Electronic Service	No	OFF_SL_21-694_M-21-694
Yochi	Zakai	yzakai@smwlaw.com	SHUTE, MIHALY & WEINBERGER LLP	396 Hayes Street San Francisco, CA 94102	Electronic Service	No	OFF_SL_21-694_M-21-694
Thomas J.	Zaremba	TZaremba@wheelerlaw.com	WHEELER, VAN SICKLE & ANDERSON	44 E. Mifflin Street, 10th Floor Madison, WI 53703	Electronic Service	No	OFF_SL_21-694_M-21-694
Christopher	Zibart	czibart@atcllc.com	American Transmission Company LLC	W234 N2000 Ridgeview Pkwy Court Waukesha, WI 53188-1022	Electronic Service	No	OFF_SL_21-694_M-21-694
Patrick	Zomer	Pat.Zomer@lawmoss.com	Moss & Barnett a Professional Association	150 S. 5th Street, #1200 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_21-694_M-21-694