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Direct Testimony and Schedules
David C. Harkness

Before the Minnesota Public Utilities Commission
State of Minnesota

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

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

Business Systems

November 1, 2019

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is David C. Harkness. I am the Senior Vice President, Customer Solutions for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy). I have spent the last decade as Senior Vice President and Chief Information Officer (CIO) at Xcel Energy.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 35 years of experience in Information Technology (IT), with 30 of those years in a management role. As I transition to my new role leading Customer Solutions, I remain a subject matter expert for Xcel Energy based on the past decade serving as Senior Vice President and Chief Information Officer (CIO), where I was responsible for the XES Business Systems organization, which provides IT services to Xcel Energy's shared services and the operating companies. In this role, I was also responsible for information technology disaster recovery.

Before I joined Xcel Energy and Northern States Power Company in November 2009, I spent six years at PNM Resources in New Mexico, where I first served as Senior Director, Business Process Outsourcing, then as Senior Director of Business Transformation and, finally, as Vice President and CIO. While in New Mexico, I was also appointed by Governor Richardson to New Mexico's Information Technology Commission, where I helped establish and direct the IT Strategy for the State of New Mexico. Prior to that experience, I held several IT Leadership roles for McLeod USA, MCI, and Rockwell International, where I began my career in 1986.

My résumé is attached as Exhibit___(DCH-1), Schedule 1.

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

A. I present and support the Company's capital and operation and maintenance (O&M) budgets during the period of the 2020-2022 multi-year rate plan (MYRP) for the Business Systems area. I also support the Company's Advanced Grid Intelligence and Security (AGIS) initiative, which consists of major grid modernization efforts to be completed in cooperation between Business Systems and the Xcel Energy business areas that will use the system.

Q. PLEASE PROVIDE AN OVERVIEW OF THE BUSINESS SYSTEMS AREA WITHIN XCEL ENERGY.

A. Business Systems provides IT services across Xcel Energy. Like all utilities, Xcel Energy must invest in computers, software, networks, mobile devices and other IT services each year in order to (among other things):

- Coordinate work in the field;
- Interact with customers;
- Operate and dispatch generation facilities;
- Run our transmission system;
- Provide information to our state and federal regulators;
- Purchase fuel;
- Bill and collect efficiently;
- Develop budgets and track expenditures;

- Manage vendors and vendor contracts; and
- Pay employees.

Each of these activities is necessary to provide reliable electricity and a positive customer experience. No relevant business, including utilities, can function without dependable and up-to-date IT capabilities for both customers and employees.

Q. CAN YOU ALSO PROVIDE AN OVERVIEW OF THE WORK BUSINESS SYSTEMS WILL BE PERFORMING OVER THE NEXT FEW YEARS?

A. Yes. Over the next three years, Business Systems will continue much of the fundamental IT work described in our last Minnesota rate case, including replacing aging technology; protecting customers and the Company against cyber security risks and attacks; and strategically enhancing our IT capabilities to improve our customer and employee experiences. We will continue to be flexible and nimble, addressing new technologies and needs as they emerge within the resources available to us.

Technology changes constantly. With a typical life of roughly three to seven years for NSPM (depending on the system), the average lifespan of IT assets is considerably shorter than it is for many business areas. Although we have been able to return great value from larger systems, on average our assets need attention frequently, especially related to unexpected technology changes.

With respect to replacing aging technology, we continue focus on making sure our employees have the basic technology tools needed for the provision of electricity to customers. While some of these tools (e.g. desk and laptop computers, mobile phones, software versions) need to be patched, updated, or replaced on a reasonably regular basis to keep up, in other areas we have been able to strategically harvest maximum value from older systems and delay investments. In the last Minnesota rate case, I described how our capital and O&M investments would increase because we had previously delayed new investments to the maximum extent. We have now begun replacements for some of these systems. For example, we waited to update to the Windows10 operating system (which was released in 2015) until 2019.

In addition to keeping technology updated, we need to maintain the security of data belonging to our customers, our employees, and our business. Knowing that we will continue to identify new cyber security risks over the next several years, we must proactively make the necessary investments to ensure data security.

Moreover, there are areas where we not only need to replace old systems, but we also have the opportunity to enhance our capabilities and become more efficient. As an example, in 2018 we implemented Blue Prism Process Automation in the financial operations area. The project leverages automation technologies, such as robotic process automation, smart workflows, and natural language processing to streamline workloads. This helps ensure a better, more efficient, and faster financial close by leveraging technology to maximize our employees' time.

Additionally, in an era where customer's expectations are higher than they have ever been, we are turning our attention to enhancing our customers' experience with their utility and electric service by leveraging data, interactive technology through the web and digital interfaces to improve our customers' options for energy usage, monitoring, and services. We are embarking on an enterprise-wide effort to advance and modernize the Xcel Energy customer experience, including updating existing systems such as our website and MyAccount through our Customer Experience Transformation programs, and enhancing the distribution grid and associated customer services with an eye toward the future through our Advanced Grid Intelligence and Security (AGIS) initiative.

Q. PLEASE PROVIDE A SUMMARY OF YOUR TESTIMONY.

A. In my Direct Testimony, I describe the Business System organization, as well as some of the IT and business continuity services we provide. I carry forward the discussion from our last electric rate case in Minnesota, illustrating that our capital and O&M investments have increased in light the rising importance of IT in our business. As technology continues to evolve, I explain the kinds of investments we are currently making, why they are important to meet our customers changing energy needs, and how we work to ensure reasonable costs for those investments.

I explain that we are proposing capital additions of approximately $146.3 million for 2020, $134.1 million for 2021 and $134.1 million for 2022 on a total Company basis.[1] I provide support for the key investments during the MYRP term (2020-2022).

I begin by walking through the major capital projects outside of AGIS that

[1] All costs in my testimony are stated on a NSPM total company basis unless otherwise noted.

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comprise these budgets, organizing projects by our aging technology, cyber security, customer experience, enhancing capabilities, and emergent demand budget groupings.

I then discuss the Business Systems O&M budget for 2020 through 2022, which is driven by employee labor and non-labor costs, software maintenance, network communications, application development, and distributed systems such as servers, data storage, and desktop computer and printer maintenance. I explain why our O&M budget is reasonable and reflects the types of expenditures we must make to keep the technology side of our business running productively.

Next, I describe in detail why a major component of Business Systems' capital additions consist of our AGIS initiative, and how we have carefully planned for this needed investment. Building on introductory testimony by Company witness Mr. Michael Gersack and Distribution Operations testimony by Company witness Ms. Kelly Bloch, I explain Business Systems' role in developing the strategy, support, security, and implementation plans and activities for the components of AGIS, including the Advanced Data Management System (ADMS), Advanced Metering Infrastructure (AMI), the Field Area Network (FAN), Fault Location, Isolation, and Service Restoration (FLISR), and Integrated Volt-VAr Optimization (IVVO). I further explain how the Business Systems costs of the AGIS initiative were developed both for the term of this rate case multi-year rate plan (MYRP) from 2020-2022, as well as over the longer term for purposes of both the Company's concurrently-filed Integrated Distribution Plan (IDP) and the cost-benefit analysis supported by Company witness Dr. Ravikrishna Duggirala. Company witness Mr. Christopher Cardenas provides additional discussion of how the AGIS initiative benefits customers through our Customer Care area.

Q. HOW HAVE YOU ORGANIZED YOUR TESTIMONY?

A. My testimony is organized into the following sections:

- *Section II* – Business Systems Overview
- *Section III* – Capital Investments
- *Section IV* – O&M Budget
- *Section V* – The Advanced Grid Intelligence and Security Initiative
- *Section VI* – Conclusion

II. BUSINESS SYSTEMS OVERVIEW

Q. PLEASE DESCRIBE BUSINESS SYSTEMS' KEY ROLES AND RESPONSIBILITIES.

A. Business Systems is the Company's centralized IT organization, providing technology services across all operating companies, including NSP-Minnesota. These services include support for the following business operations:

- *Foundational Technology Infrastructure*. Business Systems is responsible for providing support for each employee's hardware and software needs. This includes maintaining and updating the operating system used on employee computers and providing sufficient data storage capabilities. Business Systems is also charged with protecting the security of the Company's data from cyber attacks.
- *Systems Controls*. Business Systems provides technology support to our generation, transmission, and distribution units to help manage and operate the electric and gas systems. This includes providing and supporting software applications such as Supervisory Control and Data

Only the testimony necessary to support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative have been included in the Integrated Distribution Plan (IDP) filing. Accordingly, we have excised non-AGIS pages from this attachment.

V. THE ADVANCED GRID INTELLIGENCE AND SECURITY INITIATIVE

A. Introduction

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

A. In this section, I discuss the IT integration and cyber security support for the Company's Advanced Grid Intelligence and Security (AGIS) initiative and provide detailed support for the recovery of associated costs incurred by the Business Systems organization, including both capital and O&M. As discussed by Mr. Gersack, the Company is requesting approval to recover the costs of the capital investments and O&M expense for the components of AGIS that we propose to implement during the MYRP, and is also requesting that the Commission certify these projects so the Company may request recovery of costs for 2023 and later in subsequent rider filings (subject to all other requirements of rider recovery). Accordingly, while I focus this discussion somewhat on the term of the multi-year rate plan, I also provide support for the IT portions of the broader AGIS initiative, consistent with the Company's Integrated Distribution Plan (IDP) being filed concurrently with this rate case.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. I first describe the AGIS initiative and present an overview of the Business Systems and IT services that will integrate the various components of the AGIS initiative.

I then discuss the cyber security measures that will protect the more intelligent, interactive electric distribution network as well as the underlying data it gathers. I describe the Company's security principles, and explain the protection that will be implemented to secure customer endpoints and the communications network that facilitates the movement of data through the advanced grid. Overall, I explain how the Company continually identifies and implements cyber security best practices to protect customers and the distribution grid. Reliable delivery of electricity is of paramount importance, protecting the integrity and security of this system is included with that responsibility.

I then discuss the IT infrastructure that will support all aspects of the AGIS initiative. I discuss each component, the implementation plan, and the associated costs for Business Systems. While the more visible components of the AGIS initiative are described by other Company witnesses, supporting IT infrastructure and integration of the components of AGIS will allow new applications and field devices to communicate with and deliver data to the Company's "back office applications." In other words, IT enables the software applications that support the Company's customer service needs, billing, payment remittance, service order management, outage management, meter reading, and asset inventory lifecycle management applications to utilize the customer data, outage data, and other information supplied by the advanced distribution grid.

This discussion includes the implementation plan for the Company's IT integration efforts, which will begin in 2020 and will continue as AGIS components are implemented during the term of the multi-year rate plan. I also describe the IT support necessary to facilitate certain customer interaction points, such as a customer internet portal that utilizes communications with advanced meters to provide timely energy usage information to customers.

Finally, I provide support for the capital and O&M costs related to the IT integration and cyber security for AGIS for which we are requesting recovery in this case. In turn, these costs flow through the Company's cost-benefit analysis presented by Dr. Duggirala and Mr. Gersack. Because hardware and software systems and integration work are critical foundations of the AGIS initiative but do not provide quantifiable benefits until they are deployed and utilized in conjunction with distribution systems, my discussion of customer cost-benefit analyses is limited to costs.

Following is an outline of the remainder of this section of my testimony. A more detailed outline including subheadings can be found in the Table of Contents.

- AGIS Overview
- IT Support for AGIS
- Distribution Grid Cyber Security
- AGIS Components, Implementation, and IT Costs
    1. Introduction and Overview
    2. Grid Modernization Efforts to Date
        - *ADMS*
        - *TOU Pilot*
    3. AMI
        - *AMI Overview*
        - *AMI Integration*
        - *AMI Costs*

4. The FAN
    - *FAN Overview*
    - *Interrelation of FAN with Other AGIS Components*
    - *FAN Benefits*
    - *FAN Implementation*
    - *FAN Costs*
    - *Minimization of Risk of Obsolescence for FAN*
    - *Alternatives to FAN*
5. FLISR
6. IVVO
7. AGIS IT Overall Costs and Implementation

Q. HOW IS THE COMPANY PRESENTING ITS OVERALL SUPPORT FOR THE AGIS INITIATIVE?

A. A discussion of the overall AGIS initiative is provided in the Direct Testimony of Company witness Mr. Michael C. Gersack. In addition to my testimony, information on the AGIS distribution system components and customer benefits and other considerations is provided in the Direct Testimonies of Company witnesses Ms. Kelly A. Bloch and Mr. Christopher C. Cardenas. The AGIS cost and benefits analyses are provided in the Direct Testimony of Company witness Dr. Ravikrishna Duggirala.

B. AGIS Overview

Q. WHAT IS AGIS?

A. The AGIS initiative is a comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. AGIS provides the foundation for an interactive, intelligent, and efficient grid system that will be even more reliable and better prepared to meet the energy demands of the future.

Q. TO PROVIDE A FRAMEWORK FOR THE REMAINDER OF YOUR TESTIMONY, PLEASE IDENTIFY THE CORE COMPONENTS OF AGIS.

A. The core components of AGIS are the Advanced Distribution Management System (ADMS); Advanced Metering Infrastructure (AMI); the Field Area Network (FAN); Fault Location Isolation and Service Restoration (FLISR); and Integrated Volt-VAr Optimization (IVVO). More specifically:

- *Advanced Distribution Management System (ADMS)* is a foundational system for operational hardware and software applications. It acts as a centralized decision support system that assists control room personnel, field operating personnel, and engineers with the monitoring, control and optimization of the electric distribution grid. ADMS also includes the data enhancements for the Geospatial Information System (GIS), which is a foundational data repository that provides location and specification information for all of the physical assets that make up the distribution system. ADMS uses this information to maintain the as-operated electrical model and advanced applications.
- *Advanced Meter Infrastructure (AMI)* is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI provides a central source of information that is shared through the communications network with many components of an intelligent grid design.

- *Field Area Network (FAN)* is the communications network that will enable communications between the existing communications infrastructure at the Company's substations, ADMS, AMI, and the new intelligent field devices associated with advanced grid applications.
- *Fault Location Isolation and Service Restoration (FLISR)* involves software and automated switching devices, as an additional component of the ADMS, that reduce the frequency and duration of customer outages. These automated switching devices detect feeder mainline faults, isolate the fault by opening section switches, and restore power to unfaulted sections by closing tie switches to adjacent feeders as necessary.
- *Integrated Volt-VAr Optimization (IVVO)* is a significant additional component supported by ADMS, as it automates and optimizes the operation of the distribution voltage regulating and VAr control devices to reduce electrical losses, electrical demand, and energy consumption, and provides increased distribution system injection capacity to host DER.

C. IT Support for AGIS

Q. WHAT ROLE DOES INFORMATION TECHNOLOGY PLAY IN THE ADVANCED DISTRIBUTION NETWORK?

A. As discussed in the Direct Testimony of Mr. Gersack, the Company envisions an increasingly intelligent, automated, and interactive electric distribution system that utilizes advancements in sensing, controls, information, computing, communications, materials and components. This greater intelligence and automation is dependent on information technology to share and analyze information, integrate systems, and support the advanced infrastructure in a timely and efficient manner. In turn, through the AGIS initiative the more advanced distribution system will be able to better meet customers' energy needs, while also integrating new sources of energy and improving grid reliability.

Q. PLEASE INTRODUCE THE WORK THAT WILL BE REQUIRED OF BUSINESS SYSTEM TO SUPPORT THE AGIS INITIATIVE.

A. Overall, Business Systems is responsible for the IT integration of AGIS systems and data with other back office applications existing at the Company. For example, Business Systems will implement the FAN that allows intelligent field devices, ADMS, AMI, and other systems to connect. Business Systems has already implemented many foundational components of the AMI software for use in Colorado, and in Minnesota for the Residential Time of Use (TOU) pilot. This same software will provide features and data processing to support a full Minnesota rollout, and will be enhanced to support Minnesota requirements for capacity, performance, security, and functionality. From the AMI head-end, a combination of new or enhanced interfaces will be built to transfer the data to other applications, such as ADMS, the meter data management system, the billing and customer service system, and the asset inventory management system.

Implementing AGIS will require the various interfaces to transfer large volumes of data in a small amount of time. We will also be obtaining significantly more data from the field devices than we have in the past. This additional data will require additional space for storage and a data management plan to ensure we are keeping the necessary data only for as long as it is needed. The new software, additional server hardware, and increase in quantity of data stored will all need to be supported, which will require an increase in our support staffs.

Q. WHAT DO YOU MEAN BY IT INTEGRATION?

A. By IT integration, I refer to the need to integrate the technical components of the AGIS initiative (*i.e.*, the ADMS, AMI, FAN, FLISR, and IVVO systems) with other Company applications to allow the efficient, timely, and secure transfer of data between AGIS systems and other Company systems. The goal of integration is to ensure new applications and data are able to communicate with our existing applications so we are able to use the data to improve Company operations and provide a better customer experience.

As one example, AMI meter data must be communicated to the ADMS for operations and management of the grid, and to back-office applications such as billing and customer care for the data to be used consistently and as effectively as possible. As the business processes are defined or refined, the necessary data and applications requiring the new data gathered from the AGIS components will be identified. Interfaces will be designed or significantly enhanced to transfer the data between the applications. New interfaces to support the new business processes will require significant labor to design and implement. We will need to use existing tools, such as an Enterprise Service Bus (ESB),[3] to make the implementation and support of the interfaces consistent and efficient.

[3] The ESB is a type of software platform that works behind the scenes to aid application-to-application communication. The ESB can be thought of as a "bus" that picks up information from one system and delivers it to another.

Q. TO WHAT EXTENT DOES BUSINESS SYSTEMS ANTICIPATE ENHANCEMENTS TO BACK-OFFICE APPLICATIONS MAY BE NECESSARY AS A RESULT OF AGIS?

A. The new AMI field devices will provide data we have not stored in our systems before and this data will be in larger quantities than we have obtained before. As a result, effective use and communication of this data will require upgrades to many of our existing business processes. While our project plans have identified these upgrades and enhancements, there may be some additional requirements that will not be fully determined until the AGIS initiative is approved and final requirements are determined.

Q. CAN YOU DISCUSS FURTHER THE TYPES AND VOLUME OF DATA YOU WILL BE RECEIVING FROM THE FIELD AND MANAGING AS A RESULT OF AGIS IMPLEMENTATION?

A. Yes. The volume of data will increase by orders of magnitude. Related to AMI metering, we will have the capability to obtain data from meters many times a day – and will be able to provide this data to customers on a daily basis (or more frequently) via the customer data web portal or smartphone application. Not only will the advanced meters provide energy usage data, they can also measure voltage, current, frequency, and power quality. Additionally, these meters can detect outage events, restoration events, tampering, energy theft events, and perform meter diagnostics. This is in contrast to our current metering system which generally provides energy usage data once per month for billing purposes.

In addition to the meter data, the advanced grid components FLISR and IVVO will provide outage and voltage information that will be used for outage response as well as for grid management and planning purposes.

To support the new data and processes, the Company will need to enhance some software applications to accommodate new fields and increase the applications data storage capacity and processing.

Q. WHY DOES THE COMPANY NEED TO INTEGRATE THE COMPONENTS OF THE AGIS INITIATIVE WITH OTHER COMPANY SYSTEMS?

A. To realize the benefits of advanced grid capabilities and coordinate service delivery to customers as well as the work of our personnel, it is essential that we integrate our systems to coordinate timely, accurate information. Integration of systems ensures that new AGIS systems and components distribute and receive information that is synchronized across all impacted business processes. Integration is fundamental to keep large volumes of data timely, accurate, and consistent between systems of record. Integration is also key to securing the technologies we are deploying.

Conversely, compromising the integration of systems would significantly diminish the customer experience and reduce the processing and decision making that is required to manage energy services that our customers want. Lack of integration would require that customers and Company employees obtain different information from different sources or applications, creating the risk of error and making it more difficult and more time consuming to obtain and provide information, which can results in additional costs.

As the use of integrated systems matures, the Company will be able to use information from many different, integrated sources to assist in managing the electric grid and maximizing the benefits of AMI for our Minnesota electric customers.

Q. HOW WILL AMI AND BACK OFFICE APPLICATIONS BE INTEGRATED?

A. The Company will connect the AMI meter with the AMI head-end software that sends commands to meters and receives data from the meter using the FAN communication network. From the AMI head-end, data will be distributed to back office applications to enable the Company and customers to use this data in a meaningful way. ADMS data from field devices, including advanced meters, will also be distributed to various back office applications, to enable the Company to manage the distribution grid more effectively and efficiently.

Q. ARE THERE ASPECTS OF IT INTEGRATION FOR THE AGIS INITIATIVE THAT WILL HAVE TO BE DEVELOPED AS THE PROGRAM IS IMPLEMENTED?

A. Yes. While we know a great deal of the integration work that will be necessary, the full extent of the IT work to be completed in Minnesota cannot be completely anticipated ahead of time due to the need for additional filings and the need for future decisions that will depend on technology advances as time goes on. For example, as discussed by Mr. Cardenas, we will be submitting separate filings with the Commission for approval of opt-out provisions and to enable remote connection/disconnection capabilities. Once these proceedings are completed and requirements are finalized, we will be working on details to implement these processes, ensuring they comply with Minnesota requirements that may be established. As time progresses, we will also learn additional information regarding the level and type of application enhancements that will be needed. Therefore, a contingency has been added to the current cost estimates. Once those details are finalized and project plans are refined accordingly, we will be able to further refine project cost estimates. I describe our current cost estimates later in my testimony, after

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first describing how the Company is hardening the advanced grid against cyber threats.

D. Distribution Grid Cyber Security

Q. HOW IS CYBER SECURITY INTEGRAL TO THE AGIS PLAN?

A. Cyber security is a significant element of the AGIS plan. It starts with identification and protection of all components of the intelligent grid, both for the protection of customers and for the reliable and safe delivery of energy to customers. Also included are detective controls at strategic locations to provide early notification of suspicious behavior or anomalous activity. Further, the Company plans, refines and exercises to react appropriately to threats to the intelligent grid.

Q. DOES XCEL ENERGY HAVE A CYBER SECURITY BUSINESS AREA?

A. Yes. In addition to Business Systems, the Company has a dedicated Enterprise Security Services (ESS) business unit that encompasses both cyber and physical security, security governance and risk management, and enterprise resilience and continuity services. This combination of services is designed to cover analysis of vendor risks, alignment of the technology with security standards, secure solution design and deployment, integration with Company solutions including user access management and system monitoring and incident response, as well as threat analysis and planning for continuity of business operations in the event of a disruption.

The Company's security risk management program provides Company leaders with information about threats and the level of security risks, so that mitigations and responses can be planned that are proportional to the risk.

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The separation of ESS from Business Systems is a beneficial organizational structure in that it provides multiple layers of security oversight on an enterprise-wide basis, not just under the IT organization. ESS staff and programs, however, are tightly integrated into the AGIS program, and the ESS costs specifically related to AGIS are included in the Business Systems AGIS budget presented below.

Q. WHAT ARE SOME OF THE GENERAL TYPES OF SECURITY RISKS THAT MUST BE TAKEN INTO ACCOUNT FOR ANY UTILITY DISTRIBUTION SYSTEM AND CUSTOMER METERS?

A. First, devices in the field must be protected proportionately. Consequently, unlike internal business technology, the distribution components are out in the field and at customers' residences; devices can only be hardened so much, and security must also rely on other controls. Additionally, although even legacy distribution systems and meters are vulnerable to physical tampering and disabling, adding a communications network enhances the potential impact of a security compromise. In short, the endpoints and the communications between them all require security protections.

Q. DOES IMPLEMENTATION OF THE AGIS INITIATIVE SOLVE SOME OF THE CYBER SECURITY CHALLENGES PRESENTED BY THE COMPANY'S CURRENT DISTRIBUTION GRID?

A. Yes. For example, our current meter reading technology was implemented beginning in the 1990s; thus, it does not have state-of-the-art access controls, encryption technologies, or monitoring capabilities. Further, it is not capable of two-way communications, and the security architecture it is built upon is inadequate. The two-way communication enabled with AMI metering provides additional information to the Company about changes to the meter that can help prevent and identify meter theft and tampering, as described by Mr. Cardenas.

Further, the addition of a communication network provides additional capabilities and services to our customers, as well as greater insight into our system, but can also increase the potential impact of a cyber security compromise. The addition of a Company-owned Field Area Network is a prudent approach to this concern. A private network allows Company to better control the integrity of the devices on its network and the data exchanged with those devices. The alternative, a public network, would expose the devices to increased risk because the Company would not be in control of the network.

Overall, while the implementation of the AGIS initiative solves certain existing issues, it also presents different challenges to security than a less advanced grid, and requires its own comprehensive security strategy.

Q. CAN YOU PROVIDE MORE SPECIFIC INFORMATION REGARDING THE SECURITY RISKS THE COMPANY IS ADDRESSING AS PART OF THE AGIS INITIATIVE?

A. Yes. Security controls are designed for each component and system implemented as part of the AGIS initiative. The security risks associated with the AGIS components can be organized into three primary areas: compromise of meters and devices; exploitation of the communications channels; and security lapses once data is within the corporate environment. There are also security risks related to the web portal, as well as future customer applications and new products and services that will be enabled by the advanced grid.

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First, advanced meters and other networked devices have an integrated network interface card (NIC) that enables them to connect to the WiSUN network. The Company leverages both physical and cyber security controls to protect NICs from unauthorized access.

Second, a compromise of the WiSUN and WiMAX networks that carry traffic to and from the meters and field devices could lead to disruption or alteration of information needed for grid management. Therefore, protecting the integrity of the communication devices and channels that allow the advanced grid to perform at expected levels is paramount. 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 access sensitive data or issues commands to the grid. There are many controls in place to prevent and detect such behavior.

Q. DOES THE COMPANY EMPLOY BEST PRACTICES FOR CYBER SECURITY?

A. Yes. 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 against CIA (Confidentiality, Integrity and Availability) breaches. This framework serves as the basis for project security requirements as well as periodic internal security technology control assessments.

1. Cyber Security Principles

Q. WHAT ARE THE CYBER SECURITY BEST PRACTICES FOR XCEL ENERGY?

A. The Company's cyber security program may best be described in terms of the five categories of controls outlined in the NIST CSF: identify, protect, detect, respond, recover. Combining these for "defense in depth" adds multiple layers of protection and detection including defenses at each endpoint and throughout the network. Controls within these layers include:

- Asset management – maintain an inventory and securely configure assets, so we know what to protect as well as what is authorized to access our networks ["Identify"];
- Protection – user access controls, encryption, digital certificates and other controls to ensure the confidentiality, integrity and availability of data ["Protect"];
- Vulnerability management – in addition to scanning equipment for known security vulnerabilities, the company monitors emerging threats ["Detect"];
- Monitoring and alerting – identify potentially anomalous activity so that both proactive and reactive responses are appropriate and efficient ["Detect"];
- Incident response – analyze information using playbooks and escalate to the Enterprise Command Center, the Company's 24x7 watch floor operation designed to prepare for, respond to, and recover from any potential hazard that may impact customers, Company assets, operations, or its reputation ["Respond"]; and

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- Disaster recovery and business continuity planning – to efficiently maintain and restore grid operations in the event of a cyber attack [“Recover”].

Cyber security threats are monitored and as new types of threats emerge, the Company adjusts our “defense in depth” strategy accordingly.

Q. HAS XCEL ENERGY IMPLEMENTED THE CYBER SECURITY BEST PRACTICES YOU DESCRIBED?

A. Yes. These cyber security controls will be applied to the technology to be implemented as part of the AGIS initiative to identify and protect all components of the intelligent grid and help ensure the reliable and safe delivery of energy to the Company’s customers. The following discussion explains how these controls are being applied, at the endpoints, on the communications channels, and within the corporate environment.

2. Endpoint Protections

Q. FIRST, WHAT DO YOU MEAN BY ENDPOINT?

A. An endpoint in this context refers to the intelligent devices on our system. This includes the AMI meter and head-end, but also includes communication devices such as routers or switches. As a point of reference, the concept of “endpoints” is not limited to distribution system field devices; it also includes other end user devices, such as Company personal computers and network servers. However, my testimony is focused on distribution grid devices.

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Q. WHAT IS ENDPOINT PROTECTION?

A. Endpoint Protection is the installation and/or enablement of protective and detective cyber security controls to thwart malware and external influences from causing unexpected, unwanted or invalid behavior at an endpoint.

Q. WHAT TYPES OF ENDPOINT PROTECTION HAS XCEL ENERGY IMPLEMENTED?

A. Xcel Energy's Endpoint Protections include: (1) Access Controls including Authentication and Authorization; (2) System Patching; and (3) Data Validation and Protection. These endpoint protections were specified as cyber security controls in the AMI vendor selection process, as they are essential to protect the devices and the data that are handled by AMI meters and headend servers. The vendor selection process is described later in my testimony and in Ms. Bloch's testimony. Authentication and Authorization is integral to Access Control for any type of endpoint so that logical access to endpoints can only be performed by duly authorized personnel.

Q. PLEASE DESCRIBE ACCESS CONTROL.

A. The first item of protection, Access Control, is to confirm that only necessary and authorized users have access to the individual devices. This not only includes the devices that are installed on the consumer's premises, but also the devices that facilitate communication and control of the data flowing to the consumer. There are potentially many avenues of compromise with respect to unauthorized access to devices. This is a key consideration and will be addressed through strong authentication methods, which include multi-factor authentication methods described below.

Q. PLEASE DESCRIBE AUTHENTICATION AND AUTHORIZATION.

A. Authentication is a method by which a user affirms their identity. In its simplest form, it involves a user ID and password. Where technically feasible, Xcel Energy requires multi-factor authentication so that a user must not only know their password, they must also possess a physical or logical token. This minimizes the ability of an unauthorized user to steal passwords and access our assets and information.

Authorization is the process of determining and configuring the minimum level of access required by a user or an automated system. Granting undue permissions to devices that comprise the intelligent electric distribution system could lead to unauthorized or inadvertent changes and instability. Complying with a least-privilege principle ensures that only necessary and authorized individuals have the ability to make administrative changes.

Sound access controls include periodic review of access levels and removing access when it is no longer needed.

Q. PLEASE DESCRIBE SYSTEM PATCH MANAGEMENT.

A. Device and system manufacturers periodically issue 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.

Q. PLEASE DESCRIBE DATA VALIDATION AND PROTECTION.

A. A final defensive layer between the various endpoints is data validation. As data is sent from endpoints at consumer premises, data validation at the head-end must take place. If data values received from the consumer endpoint do not fall within a range of expected values, then either the data must be assumed compromised and discarded, or secondary validation must take place to measure the integrity of the data received. This validation will provide yet another level of detection and protection for the intelligent electric distribution system.

Each of these endpoint protections will support the overall security of the AGIS technology.

3. Communication Network Security Protections

Q. AS PART OF IMPLEMENTING CYBER SECURITY, DOES THE COMMUNICATION NETWORK ALSO NEED TO BE PROTECTED?

A. Yes. The communication network that facilitates data movement from the endpoint at the consumer premise to the utility's control center must also have a high level of security built into the architecture to ensure confidentiality, integrity, and availability of the intelligent electric distribution network.

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Q. WHAT ARE THE PROTECTIONS XCEL ENERGY APPLIES TO THE COMMUNICATIONS NETWORK?

A. The equipment that makes up the communication network deploys the endpoint protections previously discussed. Additional key controls for the communications pathways include the use of firewalls to restrict which systems can interact and what ports and protocols they can use; encryption to minimize the opportunity to intercept and alter data traffic; monitoring and log review as well as response to suspected security events.

Q. PLEASE DESCRIBE HOW FIREWALLS ARE USED TO PROTECT COMMUNICATIONS.

A. 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.

Q. PLEASE DESCRIBE ENCRYPTION.

A. 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.

Q. DOES EVERY COMMUNICATION CHANNEL OR MEDIUM NEED TO HAVE THE SAME LEVEL OF PROTECTION?

A. Yes. The FAN solution described earlier in my testimony employs multiple technical protocols (WiMAX and WiSUN), as well as cellular. In order to ensure an efficient and holistic approach is taken to the intelligent electric distribution network, it must interoperate with all available communication mediums. The equipment that facilitates the specific communication medium must not impede the security controls placed on any of the equipment identified above. Therefore, all security controls should work independently of the specific communication medium.

4. *Security Protections within the Corporate Environment*

Q. DO ANY PROTECTIONS NEED TO BE APPLIED TO ACCESS TO INFORMATION ONCE IT RESIDES WITHIN THE COMPANY HEAD END SYSTEMS?

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

Data from the intelligent electric distribution network passes through multiple defense-in-depth controls on its way back to the systems in the corporate data centers. Communication will pass through multiple firewalls to ensure that only authorized devices are communicating on authorized ports/protocols. Additionally, a protocol-aware Intrusion Detection System/Intrusion Prevention System (IDS/IPS) will inspect the traffic to ensure tampering has not been performed on the data packet. Once the data has been delivered to the systems responsible for consuming this information, only authorized processes will have the ability to act upon this information.

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

5. Other Security Protections

Q. DOES LOG MONITORING HAVE A ROLE IN THE DEFENSE OF THE NETWORK?

A. Yes. Devices that reside on the intelligent electric distribution network that have the ability to log various pieces of information and send those logs to an intelligent collector are sending them to the Security Incident and Event Management (SIEM) system. This system will collect, analyze, report, and alert on various security activity. All anomalous activity and known bad events, will be sent to the 24x7 Cyber Defense Center personnel responsible to investigate and take action upon those events. The SIEM will analyze events across systems and networks, correlating seemingly-unrelated activities for analysis and response. Additionally, copying logs to the SIEM frequently allows for better forensics than relying on source system logs which may be altered after-the-fact. Log data will be retained for an appropriate period of time to ensure any auditing activities will have sufficient data to perform a satisfactory review.

Q. DOES PROACTIVE CHANGE MANAGEMENT HAVE A ROLE IN THE DEFENSE OF THE SOLUTION?

A. Yes. In this context "change management" or "change control" is the process used to identify, analyze and approve changes to the technology environment, before those are implemented. The Company has a robust change process for computer systems, based on ITIL (formerly an acronym for Information Technology Infrastructure Library) that includes not only the steps above, but also creation of business justification, post-implementation testing (PIT) steps, and instructions for backing out a change that fails PIT. This level of rigor helps minimize unintended consequences of changes to software. Without a sufficient level of oversight and change governance, the integrity and security of individual devices, and ultimately the network, could be impacted. The absence of a sufficient level of oversight and change governance could result in the loss of information, disruption of communication, or an impact to the integrity of the data. Therefore, strict adherence to change management will be incorporated into this effort.

Q. PLEASE DESCRIBE HOW THE COMBINATION OF THESE CONTROLS IS APPLIED TO PROTECT DATA FROM THE AMI METERS

A. The Company intends to secure the smart meter by applying "defense in depth." The meter will be physically sealed and monitored to detect tampering. Meter communications will be encrypted to protect the privacy of our customers. Communications travel on the company's private FAN, hopping between authorized devices that have been registered onto the network. Firewalls control the information that travels in and out of the corporate network. The head-end validates the integrity of the data received.

The Company 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 alert the CDC to security events for investigation.

Q. DOES LIFE-CYCLE MANAGEMENT OF DEVICES HAVE A ROLE IN THE COMPANY'S IMPLEMENTATION OF CYBER SECURITY BEST PRACTICES?

A. Yes. The overall success of cyber security within the intelligent electric distribution network will be dependent upon the life-cycle management process of the equipment that makes up this network. Safeguarding this equipment is dependent upon an accurate inventory of all devices that enable this solution. Furthermore, each device must have a known and valid configuration.

Q. HOW WOULD LIFE-CYCLE MANAGEMENT OF DEVICES BE ACCOMPLISHED?

A. Life cycle management starts with selection and acquisition of devices. Cyber security requirements are provided to vendors of meters and all new distribution field devices and compliance to those requirements factors into the selection process. Additionally, the internal security practices of each vendor that will have access to Xcel Energy data is evaluated. Gaps are communicated to the vendor and remediation is requested. Xcel Energy leaders consider these gaps, or security risks, when making their purchasing decisions.

Assets are inventoried prior to deployment. In addition to operational maintenance, security patching is done when required, and approved configuration records updated. Once an asset has reached the end of its useful life, confidential and confidential restricted information is removed and the asset is destroyed.

Q. DO MONITORING AND ANALYSIS OF COMMUNICATIONS HAVE A ROLE IN THE COMPANY'S IMPLEMENTATION OF CYBER SECURITY BEST PRACTICES?

A. Yes. Continuous monitoring of this solution is important to ensure the integrity and security of the system. As conditions change within the distribution network, Distribution Operators will closely monitor the values to ensure continuous and reliable delivery of electricity to our consumers. So too must the cyber security personnel provide continuous monitoring of the systems and the communications that support the continuous and reliable operations of the equipment responsible for the delivery of electricity.

Q. WOULD OTHER ITEMS NEED TO BE MONITORED AND EVALUATED TO ENSURE THE SECURITY OF THE INTELLIGENT ELECTRIC DISTRIBUTION SYSTEM?

A. Yes. Data integrity is also an item that must be monitored and evaluated. By confirming the returned data values fall within an expected range, the integrity of the distribution control system can be maintained. Injecting bad data is a mechanism used to compromise the integrity and availability of a system without actually taking direct control over it. This would be a potential indicator of compromise to the intelligent electric distribution network and an immediate investigation would need to commence to verify whether a real attack is occurring or has occurred.

Q. HOW HAS THE COMPANY APPLIED LEARNINGS FROM OTHER UTILITIES OR BUSINESSES THAT HAVE FACED CYBER SECURITY CHALLENGES?

A. Recognizing the increased security risk of deploying intelligent devices to facilitate customer and distribution grid operations, the Company through the ESS Threat and Vulnerability Management (TVM) group has analyzed known distribution system cyber attacks, including those in Ukraine. Through analysis including a tabletop walk through of the Ukraine attacks, the Company has evaluated existing controls that would avert such attacks. TVM continues to monitor intelligence sources and work with our partners and other utilities to understand and anticipate threats to the Company.

6. *Cyber Security Costs*

Q. DO YOU HAVE ANY SEPARATE COST ESTIMATES FOR THE IMPLEMENTATION OF CYBER SECURITY FOR THE AGIS INITIATIVE?

A. No, there is not a separate cost estimate for overall cyber security. Cyber security costs are part of the application development and integration efforts described above, as they permeate all aspects of this work. As such, the costs estimates provided in Section D for the IT integration of AGIS components include costs for deployment of cyber security as part of the AGIS initiative. However, the budget does include a separate line item for project management with respect to cyber security. I discuss security project management costs in Section D, and Mr. Gersack addresses overall program management costs for AGIS implementation in his testimony.

7. *Cyber Security Summary*

Q. WHAT ARE YOUR CONCLUSIONS REGARDING CYBER SECURITY WITH RESPECT TO AGIS?

A. AGIS will bring exciting benefits to our customers, but those benefits are achievable only with a robust interconnected network and flow of data that present cybersecurity challenges. The controls I discussed above will help protect both the consumer and the distribution network, detect attacks or attempted compromise occurrences, and respond in a timely manner to limit and/or prevent impact to the consumers or to the Company. These cyber security controls are seen as a best practice, and align with the Cyber Security Framework (CSF) to Identify, Detect, Protect, Respond and Recover to known and unknown risks.

E. AGIS Components, Implementation, and IT Costs

1. Introduction and Overview

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

A. In this section, I discuss each of the AGIS components and provide detailed support for the recovery of forecasted capital additions and O&M costs for the Business Systems organization related to the AGIS initiative for the MYRP period 2020 through 2022. I also provide support for the Company's request for certification of the AGIS projects, as presented by Mr. Gersack, to allow the Company the opportunity to request recovery of costs for 2023 and beyond in a later rider filing. Mr. Gersack provides an overview of and policy support for the Company's AGIS initiative and certain Program Management costs, and Ms. Bloch provides support for the AGIS costs related to the Distribution organization.

Q. DO YOU ALSO DISCUSS BENEFITS OF AGIS FROM A BUSINESS SYSTEMS PERSPECTIVE?

A. No. IT by itself does not provide isolated benefits without the implementation of the Distribution aspects of the AGIS projects, but the benefits of AGIS could not be achieved without IT integration. Mr. Gersack, Ms. Bloch, and Mr. Cardenas are the primary witnesses describing the customer benefits driven by AGIS.

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Q. CAN YOU DESCRIBE IN MORE DETAIL HOW THE COMPANY IS SUPPORTING ITS AGIS COSTS IN THIS RATE CASE FILING?

A. Yes. AGIS costs are incurred by both Distribution and the Business Systems (IT) organization for each of the AGIS programs. There are IT components for each of the AGIS components (ADMS, AMI, FAN, FLISR, and IVVO). Business Systems is responsible for all IT components of the program. This includes the ADMS and AMI software installation and interface development to all appropriate legacy applications. In addition, IT is primarily responsible for the development and installation of the FAN components (with a portion of the installation to be completed by Distribution Operations), and network connectivity from the meters to all software components. I provide the primary support for the costs and processes for these components of these AGIS programs.

ADMS was previously certified by the Commission and costs were approved for recovery under the Transmission Cost Recovery (TCR) Rider. The Company proposes to continue recovery of ADMS costs via the TCR Rider. For 2020 and going forward, the Company proposes to recover the costs associated with the Time of Use (TOU) pilot as part of this rate case. I discuss the Business Systems support for these costs below.

Ms. Bloch provides the primary support for the costs and implementation for programs and components where Distribution has primary responsibility, including the GIS data collection effort for ADMS, the AMI meters, and installation of pole-mounted FAN devices, the advanced applications utilizing intelligent field devices (*i.e.*, FLISR and IVVO), and additional elements of the AGIS implementation process.

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Q. PLEASE SUMMARIZE THE AGIS COMPONENTS FOR WHICH THE COMPANY IS SEEKING RECOVERY, ALONG WITH THE RESPONSIBLE COMPANY WITNESS.

A. Ms. Bloch and I support the costs of the AGIS components as follows:

Table 24: AGIS Program Witness Support

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

Q. HOW ARE AGIS COSTS PRESENTED IN YOUR TESTIMONY?

A. Whereas the costs in Sections I-IV of my Direct Testimony present costs at the NSPM Total Company electric level (as usual for Business Systems costs), the AGIS capital additions presented in my testimony are provided at the Minnesota electric jurisdiction level. AGIS capital expenditures and O&M costs are stated at the NSPM Total Company electric level. The reason for this difference within my testimony is that we wanted to present AGIS costs consistently across the various pieces of AGIS testimony. Additionally, the capital expenditures and O&M costs over the longer term that I present in my

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testimony are consistent with the AGIS cost-benefit analysis.[4] For clarity in this section, all cost tables state how the specific costs are being presented.

Q. WHAT TYPES OF IT CAPITAL COSTS IS BUSINESS SYSTEMS INCURRING TO IMPLEMENT THE AGIS PROJECTS?

A. The types of IT capital costs being incurred by Business Systems include project implementation costs related to software licensing, hardware (servers and network), and implementation labor. Labor costs include requirement specification, design, application configuration, screen display development, network security configuration, testing, and implementation.

Q. WHAT ARE THE AGIS-RELATED IT CAPITAL COSTS YOU ARE SUPPORTING IN THIS CASE?

A. The Business Systems AGIS IT capital additions I am supporting for the MYRP are shown in the following table.

Table 25

AGIS Capital Additions – Business Systems- State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	2020	2021	2022
AMI	$14.2	$5.7	$8.8
FAN	$5.4	$15.9	$42.0
FLISR	$0.3	$0.4	$0.6
IVVO	$0.0	$1.7	$1.9
Total	**$19.9**	**$23.7**	**$53.4**
There may be differences between the sum of the individual AGIS program amounts and total amounts due to rounding.			

[4] As Company witness Mr. Ravikrishna Duggirala explains, the cost-benefit analysis results are stated in 2019 dollars, on a net present value of revenue requirement basis, whereas I speak to Business Systems' underlying budgets. Mr. Duggirala notes that the CBA is consistent with these budgets, but the numbers are stated on different bases.

Total AGIS IT capital additions are also set forth at the NSPM total Company Electric level in Exhibit___(DCH-1), Schedule 2 to my Direct Testimony.[5] I provide additional details and support for the IT capital costs below, organized by AGIS component.

For the years beyond 2020-2022, I discuss at a higher level the anticipated work to be done and the reasonableness or underlying assumptions for Integrated Distribution Plan (IDP) and cost-benefit analysis (CBA) purposes. In this way, I provide support for both the rate case and IDP requirements, as they are heavily interwoven. Exhibit___(DCH-1), Schedules 8, 9, and 10 to my Direct Testimony also includes currently anticipated expenditures in our cost benefit analysis beyond 2022.

Q. WHAT TYPES OF IT O&M COSTS IS BUSINESS SYSTEMS INCURRING TO IMPLEMENT THE AGIS PROJECTS?

A. The types of O&M costs Business Systems is incurring and expects to incur for AGIS include hardware support, data storage, annual software maintenance, labor for software support, and application support, which includes ongoing testing, review of processes, application of security patches to respond to evolving threats.

[5] Schedule 2 shows all AGIS additions, including ADMS, which was previously approved with costs currently being recovered under the TCR Rider.

Q. WHAT ARE THE IT O&M BUSINESS SYSTEMS COSTS FOR AGIS IMPLEMENTATION THAT ARE INCLUDED IN THE COST OF SERVICE IN THIS CASE?

A. The forecasted AGIS O&M expenses for Business Systems are shown in the table below.

Table 26

AGIS O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
AMI	\$4.2	\$13.1	\$9.1
FAN	\$0.0	\$2.1	\$1.1
FLISR	\$0.0	\$0.0	\$0.0
IVVO	\$0.0	\$0.0	\$0.0
Total	**\$4.3**	**\$15.3**	**\$10.2**
There may be differences between the sum of the individual AGIS program amounts and total amounts due to rounding.			

These O&M costs are also set forth in Exhibit___(DCH-1), Schedule 3 to my Direct Testimony,[6] along with currently anticipated costs beyond 2022 for CBA purposes. I provide additional details and support for the IT O&M costs below, organized by AGIS component.

[6] Schedule 2 shows all AGIS additions, including ADMS, which was previously approved with costs currently being recovered under the TCR Rider.

Q. TO WHAT EXTENT ARE THE IT CAPITAL COSTS PRESENTED ABOVE CONSISTENT WITH THE INFORMATION PROVIDED IN THE COMPANY'S TCR RIDER FILINGS AND ITS PRIOR IDP?

A. Project costs in the Company's 2018 IDP Filing were presented at a higher level because the Company was not yet proposing to implement its full AGIS initiative at that time. The TCR filings presented information on only ADMS and the AMI and FAN costs related to the TOU pilot, as those projects were certified to allow the Company to request cost recovery under the TCR. Further, both the TCR filings and the IDP were based on information available at that time, whereas the current rate case and IDP filings present more up-to-date information. Lastly, the Company's plan for components like FLISR incorporated feedback from the Commission, as Ms. Bloch describes in her testimony. This rate case presents the most current information on costs as our planning and data have evolved.

Q. ARE BUSINESS SYSTEMS AGIS CAPITAL AND O&M COSTS INCLUDED IN THE CBA BEYOND THE NEXT SEVERAL YEARS MEANT TO BE "RATE CASE QUALITY" NUMBERS?

A. While these cost assumptions are reasonable and well-supported based on the information available today, they are not intended to reflect more specific budgets as in a standard rate case budget. Rather, they are subject to refinement like all costs that will be incurred several years into the future. This is consistent with my experience, and with most cost projections that represent work to be completed in the longer-term. However, I believe these cost estimates are reasonable, and I explain the support for them in this section of my testimony. I provide the overall capital expenditures and O&M

costs over the AGIS implementation period 2020 through 2029 in Section 6 below.

Q. WHAT SORT OF GOVERNANCE IS IN PLACE TO ENSURE THE AGIS PROJECTS ARE COST EFFECTIVE?

A. Business Systems employs standard processes and procedures for selecting technologies to be deployed in the Company's environment as well as the execution of large capital projects. These include long established processes in the area of competitive vendor sourcing and pricing negotiations as well as technology architectural governance processes, which are discussed earlier in Section III.B of my Direct Testimony. I also discuss sourcing considerations specific to the AGIS initiative below. In addition, the AGIS program has a dedicated Project Management Office to govern all areas within the program. Mr. Gersack discusses overall AGIS governance through the Project Management Office in his testimony. The robust governance processes for the AGIS program and Business Systems ensure fulfillment of requirements and cost effective delivery.

2. Grid Modernization Efforts to Date

Q. PLEASE PROVIDE ADDITIONAL DETAILS REGARDING THE COMMISSION'S PRIOR CERTIFICATION OF GRID MODERNIZATION INVESTMENTS FOR THE COMPANY.

A. Two advanced grid investments have been submitted for certification in biennial grid modernization reports and approved by the Commission. Specifically, in the 2015 Biennial Grid Modernization Report, the Company outlined the ADMS initiative, which was submitted for certification and subsequently approved on June 28, 2016. In the 2017 Biennial Grid Modernization Report, the Company outlined its AMI and Time of Use

(TOU) pilot program and certification was approved in the Commission's August 7, 2018 Order.

a. ADMS

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK RELATED TO ADMS IMPLEMENTATION?

A. Yes. ADMS was certified by the Commission in 2016, and Distribution Operations and Business Systems have conducted their ADMS implementation activities in partnership with each other. As a utility operating in multiple jurisdictions, our enterprise-wide initiatives – like AGIS – are planned at the overall enterprise level. This allows for efficiencies and provides benefits for all our customers. Enterprise-wide planning and implementation strategies consider different timelines for project rollout in different jurisdictions. For ADMS, Business Systems completed installation of the software for Colorado, including the majority of the legacy integrations. For ADMS deployment in Minnesota, dedicated software will be implemented, design and configuration specific to Minnesota will be performed, and testing of the new NSPM environment will be executed.

Q. WHAT IS THE TIMING FOR IMPLEMENTATION OF ADMS IN MINNESOTA?

A. We expect to implement ADMS in the second quarter of 2020.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO ADMS IN THIS RATE CASE?

A. No. The Company has sought recovery for the costs for ADMS in the TCR Rider and proposes to keep ADMS in the TCR through the multi-year rate plan period.

b. TOU Pilot

Q. WHAT IS THE TOU PILOT?

A. The TOU pilot implements new residential time of use rates for select customers in two areas in the Twin Cities metropolitan area, providing customers with pricing specific to the time of day energy is consumed. This pilot requires installation of AMI meters to measure and record customer usage in detailed, time-based formats and requires installation of FAN communication to transmit this data to the Company and customers.

Q. HOW MANY CUSTOMERS ARE PARTICIPATING IN THE TOU PILOT?

A. As part of this pilot, we will deploy approximately 17,500 advanced meters to residential customers in Eden Prairie and Minneapolis. We will also deploy FAN communications to these areas.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK RELATED TO THE TOU PILOT?

A. Yes. In 2019, we began the system integration to support deployment of AMI and FAN for the TOU pilot, and the 2019 costs were certified for recovery under the TCR Rider. A description of overall AMI and FAN integration work is described in more detail in Sections 2 and 3 below.

Q. WHAT IS THE TIMING OF IMPLEMENTATION FOR THE TOU PILOT?

A. The TOU pilot is scheduled to launch, with AMI meters functioning and time of use rates available for participating customers in April 2020.

Q. WHAT ADDITIONAL WORK WILL BE NEEDED FROM BUSINESS SYSTEMS BEFORE LAUNCH OF THE PILOT?

A. The AMI and FAN operations will require a head-end system, which was completed in early 2019. Installation and configuration of both FAN and AMI components in connection with the TOU pilot will be completed in early 2020. This provides foundational two-way communication and control for the advanced meters. Specific system interfaces require significant enhancement to properly communicate, collect, and process the new information to and from these components to support the objectives in the Commission Order approving the pilot. Business Systems will also enable enhanced data availability through the customer portal and provide for enhanced Customer Care and Distribution functionality to fully implement the TOU pilot for participating customers.

Q. IS THE COMPANY SEEKING TO RECOVER ANY COSTS RELATED TO THE TOU PILOT IN THIS RATE CASE?

A. Yes. For 2020 and going forward, the Company proposes to recover the costs associated with the TOU pilot as part of this rate case. The Business Systems costs included in the MYRP period are shown in the table below.

Table 27

Residential TOU Pilot – Business Systems State of MN Electric Jurisdiction (Dollars in Millions)			
TOU Pilot – Business Systems	2020	2021	2022
Capital Additions	$4.1	$0.0	$0.0
O&M Expense	$4.2	$0.7	$0.1

As discussed in the Company's initial petition requesting approval of the TOU pilot,[7] the AMI head end software and associated integrations to support the pilot are enterprise-wide software assets developed initially for AMI implementation in Colorado. Thus for Business Systems, the implementation costs shown above reflect the estimated carrying costs associated with the asset allocated to NSPM, reflecting implementation of the TOU pilot.

I note that the residential TOU pilot costs are part of the Company's overall AGIS initiative (specific to AMI and the FAN). The TOU costs reflect the estimated portion of the total AMI component that are necessary to implement the residential TOU pilot. In her testimony, Ms. Bloch provides the Distribution costs necessary to implement the TOU pilot.

3. AMI

a. AMI Overview

Q. WHAT IS AMI?

A. AMI is a system of advanced meters, communications networks, and data management systems that enable two-way communication between utilities' business and operational data systems and meters, enabling added benefits for customers and the utility. The current metering system uses a one-way communication technology in the collection of meter data and events for subsequent download to the Company's business and customer billing systems (with limited, manual two-way communication capability). AMI meters are able to measure and transmit voltage, current, and power quality data and can act as a "meter as a sensor," providing timely monitoring that has may use

[7] See Docket No. E002/M-17-775.

cases for customers and business operations. AMI is a foundational element of the AGIS initiative because it provides a central source of information that interact with many of the other components of the AGIS initiative. Ms. Bloch provides detailed discussion of AMI and addresses the filing requirements related to AMI in her testimony.

Q. WHY DOES AMI REQUIRE INTEGRATION?

A. Because AMI consists of both software and hardware and works with other Company systems, information technology integration is key to the success of AMI.

Q. HOW WILL BUSINESS SYSTEMS PARTICIPATE IN THE AMI DEPLOYMENT?

A. The advanced meters will be integrated with the Company's IT systems. AMI is data intensive with meter readings, energy usage interval profiles, power outage and restoration events, power quality information and other data transmitted and collected frequently. All data to/from the advanced meters is transmitted to the AMI head-end application and, depending on what the data is, needs to 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 will be used and expanded upon in Minnesota for full rollout. Many of the integrations already built will be leveraged in Minnesota, and any newly required interfaces with legacy systems will be identified and developed as required to meet unique state needs.

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b. AMI Integration

Q. WHAT SYSTEMS WILL BE INTEGRATED WITH AMI?

A. The major systems to be integrated with AMI are:

- ADMS;
- Customer Resource System (CRS);
- SAP;
- Field Deployment Manager;
- Meter Installation Vendor;
- Network Management System (NMS);
- Distributed Intelligence;
- Meter Asset Lifecycle Management System;
- Meter Data Management (MDM)
- Customer portal and new initiatives; and
- the 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.

I note that the estimated work has been based upon, wherever possible, the integration work that has been completed on an enterprise-wide basis and may have been used previously to incorporate requirements in other jurisdictions. Additionally, we will need to ensure compliance with Minnesota requirements that each integration has appropriate processing capacity to additionally support Minnesota requirements.

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Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH ADMS.

A. As previously noted, ADMS will provide 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 will use the AMI data to deliver automated grid capabilities, such as FLISR and IVVO. AMI will provide the ADMS with timely real and reactive power measurement data that will be used in load flow and IVVO calculations. AMI meters will also provide voltage measurements at various points on the distribution system to support IVVO calculations. Additionally, advanced meters will report a power-out or "last gasp" event to the AMI head-end application and report a power-on event when power is restored. "Last gasp" is defined as the final message transmitted by the meter upon detection of an outage. This information will flow from the head-end application into ADMS, improving the calculations for the FLISR application. This is an enterprise-wide integration that will used or significantly enhanced, as necessary, to support Minnesota requirements.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH CRS.

A. CRS provides capabilities for customer service, billing, service orders, and payments. CRS is currently integrated with the Meter Asset Lifecycle Management System 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's premise. As another example, when a disconnected customer pays their bill, an order generated in the CRS can be

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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 disconnect an reconnect (as Company witness Mr. Cardenas notes), these capabilities can be made available. This is an enterprise-wide integration that will be used or significantly enhanced, as necessary, to support Minnesota requirements.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH SAP.

A. SAP manages the general ledger and work and asset management activities across the Xcel Energy enterprise, which were implemented between 2015 and 2017 as part of our Productivity Through Technology (PTT) initiative. 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 Xcel Energy 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 will need to be integrated with SAP across the enterprise, to support Minnesota requirements.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE FIELD DEPLOYMENT MANAGER.

A. 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, update 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 Xcel Energy, this integration is not currently constructed, and will go through standard software lifecycle steps to be implemented to support Minnesota.

Q. PLEASE DESCRIBE THE INTEGRATION OF THE COMPANY'S SYSTEMS WITH THE AMI METER INSTALLATION VENDOR'S SYSTEMS.

A. This is a new integration that is 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 Xcel Energy's systems needs to occur in order to remain track and manage activities supporting Xcel Energy customers throughout the deployment. Information that needs to be synchronized between Xcel Energy and the meter installation vendor includes customer contacts and responses, installation/removal of AMI meters, cancellation/updating of orders, disposed meters, and look ahead data. This integration will keep Xcel Energy systems that support personnel and customers reflective of the work planned and in-process. As a new integration for Xcel Energy, this will require standard software lifecycle maintenance and upgrades to be implemented as needed to support our Minnesota system and customers.

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Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE NMS.

A. 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 Xcel Energy, requiring standard software lifecycle management. The Company believes that AMI meter events and functionality can be utilized to better identify and manage service outages and restoration activity, and the volume of data available from AMI systems must be pre-processed to produce timely, accurate, consumable, and actionable information for NMS. Such an integration of AMI and NMS would improve customer experiences during service outages by making the associated event details proactively available to personnel managing, communicating and making decisions during service restoration.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE DISTRIBUTED INTELLIGENCE PLATFORM.

A. Distributed Intelligence 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 Distributed Intelligence capability allows for the installation of applications on the meter – similar to how applications are installed on a smart phone. These applications may be customer-facing, meaning the customer directly interacts with them or grid-facing, meaning Xcel Energy interacts with the applications. As discussed in Mr. Gersack's testimony, the Company anticipates deploying some applications in the near term, but broader deployment will evolve over time.

On an end-to-end basis, the Distributed Intelligence environment consists of application platform, store, gateway, service bus, security manager, hub and analytics components. While the full scope of Distributed Intelligence capabilities goes beyond initial AMI deployment as described by Ms. Bloch, this environment must be at least minimally integrated in so that Xcel Energy meters can be properly and securely registered and grouped to support the deployment, administration, management and utilization of meter-based applications and services, within Company processes that are yet to be defined. The AMI program will test and validate the expected functionality of new advanced meter processing and application environment. Mr. Gersack and Ms. Bloch provide additional Distributed Intelligence details in their testimony.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE METER ASSET LIFECYCLE MANAGEMENT SYSTEM.

A. The 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.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE METER DATA MANAGEMENT SYSTEM.

A. The Meter Data Management System provides capabilities to validate, edit, and estimate meter readings and manages events from the meter, such as power outages and tampering. The MDM will also assist in facilitating communication to, and receiving data from, the AMI head-end. The MDM is currently integrated with the Meter Asset Lifecycle Management System and CRS. The 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 our MDM. Xcel Energy recently completed an evaluation of the current MDM system application and infrastructure and determined that an entirely new solution is needed to fulfill the requirements for AMI. The current 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. A new MDM solution will be utilized enterprise-wide across Xcel Energy operating companies and we are in the process of developing the full scope of work, total costs, and determining the operating company allocation. Ultimately, the MDM solution will support the security, functionality, scalability, and performance requirements of AMI meter data management.

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Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE CUSTOMER PORTAL AND NEW INITIATIVES.

A. 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 (GB CMD). Ms. Bloch provides an introduction to the HAN capabilities, while Mr. Gersack provides additional information about the customer experience benefits of the advanced meter.

Q. PLEASE DESCRIBE THE INTEGRATION OF AMI WITH THE FAN.

A. 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 radio frequency communications modules in the meters may also act as a repeater for other mesh network devices, enabling two-way communication between the meters

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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 WiSUN 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.

Q. YOU MENTIONED THAT THE APPLICATIONS DISCUSSED ABOVE WILL SHARE DATA WITH THE COMPANY'S DATA WAREHOUSE AND OPERATIONAL REPORTING SOLUTIONS. PLEASE PROVIDE ADDITIONAL DETAILS.

A. The existing Data Warehouse is used to consolidate data from separate systems of record to facilitate efficient generation of reports and perform analysis of the data. The operational reporting solutions are expected to receive data from the AMI head-end, Meter Data Management System, and the Customer Information System. The Distribution Analytics Software is expected to use the data to perform analytics to identify trends for such items as reverse flow, tampering, load side voltage, and temperature. Once an integration solution is defined, integration details will be defined.

Q. WHAT ARE THE IMPACTS IF THE COMPANY DOES NOT MAKE THE INVESTMENTS NECESSARY TO INTEGRATE AGIS COMPONENTS WITH BACK-OFFICE APPLICATIONS?

A. Without integrating the technical components of the AGIS initiative with other Company applications, the Company and customers will not be able to utilize the benefits and capabilities of the new AGIS components. Each application provides a new capability and benefit to the Company. Without integration, existing applications would not be able to request data from new field devices, such as AMI meters, and the data provided from these new field devices would not be able to be communicated, stored, or analyzed by our existing applications. In addition, a lack of integration would cause many processes to be manual, and would not allow the ability to make decisions based on recent data collected, all of which will reduce the benefits of these technologies, especially AMI.

Q. OTHER THAN INTEGRATION, WHAT OTHER WORK WILL BUSINESS SYSTEMS PERFORM?

A. Beyond integrating systems, there are additional Business Systems work areas that are included in the scope. Ensuring that the system capacity and resiliency are installed and configured to scale to system levels inclusive of the Minnesota customers is one important work area. In addition, areas of functionality will include software configurations to support Minnesota requirements (*e.g.* rates), and system lifecycle work for meter data management, outage event processing, operational reporting, regional field deployment management, and Customer Care services to support Xcel Energy's Minnesota customers.

Q. WILL THE COMPANY PERFORM THE SYSTEM INTEGRATION WITH EXISTING RESOURCES?

A. Due to the large volume of work expected to occur over the integration period, the Company will need to hire third-party firms to supplement our existing IT resources. Estimates of costs for vendor IT work associated with AMI are part of our AGIS projects in this case, with IT cost estimates described in Section D below.

Q. WHAT WORK IS BUSINESS SYSTEMS UNDERTAKING TO INTEGRATE THE AMI PROJECT?

A. The specific functions Business Systems provides for AMI include:

- 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.
- Designing 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.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK RELATED TO AMI IMPLEMENTATION?

A. Yes. Starting in 2015, on an enterprise-wide basis, Business Systems and Distribution Operations jointly initiated a systematic approach for selecting vendors for the AMI software and legacy system integrations. Business Systems and Distribution participated in contract awards (resulting from RFP processes) for a vendor to supply the software and network WiSUN solution for AMI. The WiSUN is the mesh network portion of the FAN that will utilize the advanced meters' communications modules.

In addition, Business Systems has already completed limited AMI implementation in connection with the TOU pilot in Minnesota, and has already completed initial work for full AMI rollout in Colorado. For example, in the summer of 2019, the first set-up of legacy interface integrations were successfully implemented to support AMI meter deployments in Colorado. Full AMI implementation in Minnesota will expand on and enhance these capabilities to meet requirements for deployment in Minnesota.

Q. PLEASE DESCRIBE THE WORK BUSINESS SYSTEMS WILL UNDERTAKE IN 2020, 2021, AND 2022 FOR AMI IMPLEMENTATION.

A. As discussed by Ms. Bloch, the Company plans to deploy approximately 1.3 million AMI meters throughout our Minnesota service territory as part of the AGIS initiative starting in the fourth quarter of 2021. This deployment builds off the AMI work already completed. By the end of 2023, we anticipate that over 90 percent of the meter installations will be complete. The locations and timing of AMI meter deployment will be coordinated with the network communications installations of the FAN components.

During this period, the Business Systems organization will engage in additional interface development, scaling activities, and network communications activities. This will include augmenting legacy integrations with the AMI software based on specific requirements that will be determined once full AMI implementation for our Minnesota customers is approved. This will ensure the functionality and capacity of AMI software and that the integrated legacy systems meet the scalability needs.

c. AMI Costs

Q. WHAT BUSINESS SYSTEM CAPITAL ADDITIONS AND O&M COSTS ARE NECESSARY FOR IT INTEGRATION FOR AMI DURING THE TERM OF THE MYRP IN THIS CASE?

A. The tables below provide the capital additions and O&M costs for AMI IT capacity and integration for 2020 through 2022.

Table 28

AMI Capital Additions – Business Systems State of MN Electric Jurisdiction (Includes AFUDC) (Dollars in Millions)			
AGIS Program	2020	2021	2022
AMI	$14.2	$5.7	$8.8

Table 29

AMI O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
AMI	$4.2	$13.1	$9.1

Q. WAS BUSINESS SYSTEMS PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR AMI?

A. Business Systems is responsible for developing the forecasts for the head-end application, other software and hardware to support AMI data processing, and integrations required by those technologies. Therefore, I describe the forecast development process for these aspects in more detail in my Direct Testimony. Ms. Bloch addresses the forecast for the meters themselves.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE AMI IT FORECAST.

A. Beginning in 2015, a series of RFPs was conducted to determine the most appropriate AMI solution for the Company on enterprise-wide basis. Business Systems began looking specifically at vendors to provide the WiSUN mesh network solution for AMI, which includes the AMI head-end software. The Company received responses from industry leaders as part of its competitive bidding process. In 2017, as a result of that process, Silver Springs Inc. (which was purchased by Itron shortly after contract signing) was selected to provide the head-end software and WiSUN mesh solution for AMI. (The WiSUN equipment and field deployment are addressed in detail in the following section on the FAN.) This selection was based on optimal pricing, strategic fit, and Silver Springs' (now Itron) industry experience. This effort was benchmarked and reviewed with other utilities and industry research organizations such as EPRI. I discuss this RFP process further below. Ms. Bloch discusses the Itron selection for AMI meters further in her Direct Testimony.

In addition, beginning in 2017 and as AGIS details were developed, Business Systems worked to leverage established relationships with our existing vendors to obtain optimal pricing for the legacy integration pieces for AGIS implementation.

An additional competitive bid process was completed in 2018 to select a vendor partner for all AGIS program testing on an enterprise-wide basis. Accenture was selected for this work, which is described further below. I note that while I include discussion of this competitive bid and vendor section process here, these testing costs are not all included in the AMI budget but instead are allocated across the individual AGIS component budgets.

In 2019, we conducted an RFI process to select a vendor to provide meter data management software. Cost estimates for this component in our AGIS budget forecast are based on a detailed market analysis, and costs will be finalized once contract negotiations with the vendor are concluded. Also in progress is vendor selection for an operational reporting solution for AMI.

A detailed project estimate for the AMI head-end, mesh network solution, and IT integration was created from the pricing and contract information discussed above, as well as the incremental hardware and labor necessary to support overall AMI implementation. I discuss the RFP and vendor selection processes in further detail below. For some of the cost estimates, while specific Minnesota requirements are yet to be determined, the work performed in Colorado provides a reasonable point of reference for labor estimates for most general functional and non-functional work areas supporting Minnesota. We incorporated our previous experience into the development of cost estimates for AMI implementation in Minnesota.

(1) AMI Capital Forecast

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE AMI IT CAPITAL FORECAST?

A. The AMI IT forecast has three key components: (1) hardware, (2) software, and (3) labor.

Q. WHAT HARDWARE IS NEEDED FOR AMI IMPLEMENTATION FOR BUSINESS SYSTEMS?

A. The additional hardware necessary for AMI implementation consists of computing components used for data processing and storage to support AMI services, across all environments that are used in the software lifecycle of a particular service. Examples of environments that may be applicable to a service are production, disaster recovery, development, testing, and quality assurance. The functions that were analyzed within the hardware estimates are to support outage event processing, security, the head-end application, meter data management software, Customer Care support, reporting, database and operational storage, middleware, and field deployment. In other words, due to the increased volume of data and processes necessary to use that data in a meaningful way for our customers and the Company, additional servers with computing and storage capabilities will be needed.

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Q. HOW DID THE COMPANY DERIVE THE HARDWARE PORTION OF THE AMI IT FORECAST?

A. Xcel Energy has standards for all hardware that is deployed in our data centers. These standards define hardware for which the Company has industry benchmarked, negotiated pricing. Based on these standards, the hardware estimates were derived utilizing the hardware requirements of the applications(s) and applying standard pricing. Hardware estimates to support the head-end capacity, security services, outage processing, meter data management software, data storage capacity, and interfaces were all developed.

Q. HOW DID THE COMPANY DERIVE THE SOFTWARE PORTION OF THE AMI IT FORECAST?

A. Pricing for the AMI head-end software and mesh solution is provided in the contract with Itron, selected through the RFP process noted above. Software forecasts also include costs based on the other RFPs discussed above that have been completed or are in progress, as well as the vendor selections completed using our standard process. Pricing is consistent with industry benchmarks and our review with other utilities and industry research organizations such as EPRI. These benchmarks drove the negotiations with the selected vendors.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WISUN MESH SOLUTION FOR THE AMI HEAD-END SOFTWARE.

A. Xcel Energy issued an RFP in 2015 to select a vendor to provide the WiSUN mesh solution for the AMI head-end software. Responses were received from three different companies. Xcel Energy evaluated these vendors and responses on a number of factors including:

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- Technical performance;
- Operational performance;
- System long-term survivability;
- Adequacy of security capabilities;
- Warranty and support;
- Manageability with operational model;
- Ability to design mesh systems;
- Ability to implement;
- Ability to meeting scope and schedule;
- Acceptability of business terms and conditions;
- Industry experience;
- Adequacy of support systems; and
- Pricing.

In 2016, Xcel Energy selected Silver Springs (now Itron) and began contract negotiations. Contract negotiations were finalized in late 2016. The details of the contract awarded to Silver Springs (now Itron) included: detailed product (hardware and software) pricing; licensing pricing based on end device counts for many of the software specific applications; optional pricing for a number of potential software solutions; services pricing; and other related parts and services for future potential deployments.

Q. WHY DID XCEL ENERGY SELECT ITRON AS THE VENDOR FOR THE AMI HEAD-END AND MESH SOLUTION?

A. The primary factors in the decision were:

- Favorable pricing;

- Industry experience and track record with other utilities the Company benchmarked against;
- Performance in on-site testing of products against the Company requirements in the RFP;
- Breadth of solution; and
- Interoperability capabilities.

A summary of the RFP selection process and results are provided as Trade Secret Exhibit___(DCH-1), Schedule 11.[8]

Q. CAN YOU PROVIDE ADDITIONAL DETAIL ON HOW BUSINESS SYSTEMS WORKED WITH EXISTING VENDORS ON LEGACY INTEGRATION PIECES FOR AGIS IMPLEMENTATION?

A. Yes. Existing systems such as the Customer Resource System (CRS), Monitoring Device Management System (MDMS), Meter Reading and Acquisition System (MRAS) and Enterprise Service Bus (ESB) have existing support teams that consist of Xcel Energy personnel that are teams of employees and professional service vendors. In the case of the systems I listed, which are strictly representative, there are personnel from Xcel Energy, IBM, Accenture and product vendors that support the IT components of those systems. Integrations with those systems are key to coordinate the processing to/from new AMI systems to keep data and business processes timely, accurate and consistent. The existing support teams were engaged in the AMI delivery because they possess the knowledge of the operational environments to engage in system enhancement planning, design,

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

construction, testing and deployment to efficiently meet the requirements of AMI system integration, and ensure that existing operational requirements for those systems remain reliable.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR OVERALL TESTING OF THE AGIS PROGRAM.

A. Xcel Energy issued an RFP in February 2018 to select a vendor to provide overall testing for the AGIS program on an enterprise-wide basis. The RFP sought a vendor to provide planning and execution of all AGIS testing phases including system acceptance, integration acceptance, performance acceptance, end-to-end and user acceptance testing. Responses were received from three different companies. Xcel Energy evaluated these responses on a number of factors including:

- Approach or methods recommended for testing;
- Environment and release management;
- Resource plan efficiency and effectiveness;
- Situational problem solving; and
- Pricing.

In April 2018, Xcel Energy selected Accenture and began contract negotiations, which were finalized in June 2018.

Q. WHY DID XCEL ENERGY SELECT ACCENTURE AS THE VENDOR FOR OVERALL AGIS PROGRAM TESTING?

A. The primary factors in the decision were:

- Experience delivering similar testing for other utility customers;

- Experience and strength of team members who have previously done this work;
- Strong methodology; and
- Favorable pricing.

Q. PLEASE DESCRIBE THE RFI PROCESS THAT IS CURRENTLY UNDERWAY TO SELECT A VENDOR FOR THE METER DATA MANAGEMENT SOFTWARE.

A. In 2019, we initiated an RFI process to select a vendor to provide meter data management (MDM) software. We evaluated MDM options from three vendors. We selected a vendor based on: simplicity of technical architecture; strong availability commitment; and favorable pricing. Once the vendor was selected, we evaluated three different technology options, and have made a final technology selection. This RFI process was conducted based on our standard processes. We are currently in negotiations with the vendor and expect to complete contract negotiations in 2019.

Q. HOW WERE THE MDM SOFTWARE COST FORECASTS DEVELOPED BASED ON THE RFI PROCESS?

A. Cost estimates for this component in our AGIS budget forecast are based on the vendor quotes received during the RFI process. Costs will be finalized once the vendor negotiations are concluded. While vendor negotiations and deployment methodology are still in process, vendor pricing and product deployment sizings have been provided to allow software, hardware, and labor estimates to be built to support Minnesota.

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Q. PLEASE DESCRIBE THE OPERATIONAL REPORTING SOLUTION FOR AMI.

A. The AMI operational reporting solution will support several business use cases to deliver efficient, quality service to customers. Some example areas of operational reporting will include analysis of meter events, data quality, provisioning workflows, diagnostics, service quality and usage, and time-based data correlation and analysis using patterns and types of network and meter attributes. We are currently evaluating options for a reporting solution.

Q. HOW WERE THE REPORTING SOLUTION COSTS FORECASTS DEVELOPED?

A. Cost estimates for this component in AGIS budget forecast are based on vendor quotes we have previously received and will be finalized once vendor contract negotiations are concluded.

Q. HOW DID THE COMPANY DERIVE THE LABOR PORTION OF THE AMI IT FORECAST?

A. Our labor estimates are based on our experience and work that has already been completed for AMI implementation. Business Systems has leveraged spend information to date, for both AMI rollout in Colorado and the limited deployment of AMI in Minnesota to support the TOU pilot, to estimate the future costs associated with full deployment in Minnesota. In addition, we plan to leverage the same expertise and knowledgeable vendor partners to deliver additional capabilities for Minnesota, which will provide cost efficiencies. While specific Minnesota requirements are yet to be determined, the work performed in Colorado provides a reasonable point of reference for labor estimates for most general functional and non-functional work areas supporting Minnesota.

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Q. ARE THERE OTHER COSTS INCLUDED IN THE BUSINESS SYSTEMS CAPITAL FORECAST FOR AMI?

A. Yes. Like any other project of this size and scope, there are additional project management costs that are include in the AMI capital forecast. For the Business Systems portion of the AMI budget, these include labor costs for: (1) delivery and execution leadership; (2) testing environment/release management; and (3) security.

Q. HOW DID THE COMPANY DEVELOP THESE PROJECT MANAGEMENT COST FORECASTS?

A. These capital costs were developed using labor estimates for the work necessary to support AMI integration efforts. These costs were derived based on evaluation of prior work performed in Colorado, which provides a reasonable point of reference for labor estimates for most general functional areas supporting Minnesota.

(2) AMI O&M Forecast

Q. WHAT ARE THE PRIMARY COMPONENTS OF BUSINESS SYSTEMS' AMI O&M FORECAST?

A. The primary components of Business Systems AMI O&M costs include: (1) planning phase activities, including scope definition and solution selection; and (2) support activities that will occur after AMI is implemented, including contractor labor, maintenance, and warranty. In other words, these cost forecasts encompass the incremental work that will be necessary related to hardware and software maintenance, licensing, and the other work described above that will be necessary to support the increased data storage and processing related to AMI implementation.

Q. HOW DID BUSINESS SYSTEMS DERIVE THE FORECAST FOR AMI O&M?

A. The AMI O&M forecast was developed based on vendor quotes, existing internal support team estimates of the work required, and industry benchmarking information. Each AGIS component has an internal IT team responsible for project delivery. Our forecasts for labor costs related to AMI are based on estimates from these team members, who have previous experience with similar systems implementations and support models, including AMI implementation in Colorado. I note that there could be future sourcing decisions for different AGIS components as additional requirements are identified. The Company would use its existing sourcing processes to manage additional O&M requirements in a cost-effective manner.

(3) AMI Contingency

Q. DO THE BUSINESS SYSTEMS AMI FORECASTS INCLUDE CONTINGENCY AMOUNTS?

A. Yes. Using contingencies is consistent with project planning practices, especially for large projects that implement new technologies and require major changes to enterprise IT systems. We believe it is appropriate to include a contingency amount at this stage given that the project will be implemented over multiple years (2021-2024), as well as the complexity, size, and integrated nature of the project – with integration required for both new and legacy systems. Mr. Gersack discusses the overall AGIS project contingencies in his testimony.

Q. WHAT ARE THE BUSINESS SYSTEMS CONTINGENCIES FOR AMI?

A. The Business Systems AMI budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 37 percent.

Q. CAN YOU PROVIDE MORE INFORMATION ABOUT THE BUSINESS SYSTEMS CONTINGENCY ASSOCIATED WITH AMI?

A. Yes. Due to the integrated nature of deployment and implementation of AMI and the FAN, several reasons for including contingency amounts in the AMI budget are applicable to the FAN as well. While the FAN budget is discussed separately in the following section, I address the budget contingencies overall here to avoid duplication.

First, budget contingency amounts are appropriate due to the scale of the deployment and the volume of data that will be handled as a result of AMI implementation. As discussed above, the volume of data provided by AMI metering is orders of magnitude larger than our current metering system provides. While our project plans are appropriate with respect to the IT architecture, software, hardware, and integrations necessary to manage and use this data, additional work may be required as we cannot replicate in a test environment what will actually occur during full roll out.

Further, as we begin AMI deployment and throughout the installation phase, we will be running two metering systems simultaneously. We have planned for this, as AMI meters will not be installed for all customers until 2024. However, some level of contingency is needed to ensure that we can address any issues that arise as AMI implementation begins, so that our basic systems and provision of service to our customers remains the same for both AMI and non-AMI metered customers.

In addition, geography is important in the deployment and functioning of the AMI meters and FAN network devices. Similarly, weather may have an impact. Business Systems has conducted field coverage studies to ensure the FAN will provide adequate coverage for both deployment of meters and other devices, and our deployment plans are specific to the Minnesota geography and weather. However, we cannot duplicate some of the realities of field deployment in a test environment, so some level of contingency is appropriate.

The multi-year implementation schedule is also a reason using contingencies is appropriate. Part of IT planning requires that we will be able to address new security threats that may evolve over the implementation timeline. While the Company budgets for these eventualities at some level, contingency amounts are included because we must ensure that we are able implement security controls as new cyber threats arise.

Q. DOES THE COMPANY BELIEVE THE CONTINGENCY AMOUNTS WILL BE USED?

A. Yes; while the Company does not necessarily anticipate using all of the contingencies, we believe that some amount of contingency will be used based on experience with prior projects. Contingency amounts are included to avoid the need for tradeoffs in schedule and/or scope and functionality. In this way, we can ensure implementation of the project will help maximize benefits for our customers. As Mr. Gersack discusses, there are strict controls on how the contingency amounts may be used. The overall AGIS governance structure provides for review and approval of any project changes that will affect the scope, costs, or benefits of implementation. Any changes from budgeted amounts and any specific use of budget contingencies will need approval according to the established AGIS governance processes.

Q. FROM A PROJECT DETAIL PERSPECTIVE, ARE THERE OTHER SPECIFIC REASONS FOR INCLUDING CONTINGENCY AMOUNTS IN THE AMI BUDGET?

A. Yes. While we have based our budget estimates on all known design and installation details, there remain uncertainties with respect to specific Minnesota requirements that will not be known until after Commission approval of the projects, and unknowns that may develop through the installation phase. The level of contingency recognizes the following specifications that will be determined as we progress toward and during project implementation:

- Legacy interfaces – For AMI, we have a reasonable estimates of the type of interface work that will be necessary for Minnesota based on our previous experience with implementation in Colorado. However, the Minnesota-specific functionality will be dependent on final Minnesota requirements once approved.
- Capacity scaling – We have estimated the cost of scaling activities, but the full costs will be determined as all design and solution specifications finalized.
- MDM and operational reporting solution vendor selections are not yet finalized. Our budget estimates are based on market analysis and vendor quotes, but costs will not be finalized until we complete the selection processes and negotiate and execute contracts.
- Security – Security solutions will be dependent on final Minnesota requirements once approved.

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(4) AMI Expenditures 2020-2029

Q. WHAT ARE THE BUSINESS SYSTEMS CAPITAL EXPENDITURE AND O&M FORECASTS FOR AMI FOR 2020 THROUGH 2029?

A. The tables below provide the Business Systems AMI capital expenditure and O&M forecasts for 2020 through 2029.

Table 30

AMI Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	$11.4	$6.5	$10.0	$5.7	$0.9
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 31

AMI O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	$4.2	$13.1	$9.1	$15.2	$51.5
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

(5) AMI Cost Summary

Q. WHY IS BUSINESS SYSTEMS' AMI FORECAST REASONABLE FOR CUSTOMERS TO SUPPORT?

A. AMI is a foundational component of AGIS, which is a long-term strategic initiative to transform our electrical distribution system to enhance security, efficiency, and reliability, to safely integrate more DERs, including those that are customer owned, and to enable improved customer products and services.

The volume and scope of data processing is several orders of magnitude greater than the legacy metering infrastructure. This allows many business processes and services supporting Xcel Energy customers to be more timely, accurate and consistent. AMI will support business operations efficiencies, and a better customer experience to empower informed energy decisions. The IT components described above are necessary to implement AMI, and the AMI IT forecast is reasonable in enabling technologies that improve customer products and services.

Further, the Company employs standard processes and procedures for selecting technologies to be deployed in the Company's environment, as well as for the execution of large capital projects. Our planning for AGIS implementation is done on an enterprise-wide basis, which allows for efficiencies and provides benefits for all our customers. Consistency across the enterprise simplifies deployment across different jurisdictions in a cost-effective manner.

The processes and procedures for selecting AMI technologies include:

- *Product Selection*:
  - Head-End. The Company used multiple RFP processes to select the optimal vendor partners for various aspects of the AMI delivery. A competitive bid was completed at the end of 2017 resulting in the selection of Itron for the AMI head-end software solution.
  - Testing. An additional competitive bid process was completed in 2018 to select a vendor partner for all program testing.
  - Meter Data Management and Operational Reporting Solution. Additional processes were implemented in 2019 to select vendors

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for the meter data management software and operational reporting solutions.

- o <u>System Integration.</u> Negotiated individual statements of work were developed with existing vendors that own and support each of the interfacing applications. We leveraged our long-standing partnerships with these vendor in an effort to obtain optimal costs for the integration effort.

- *Project and Initiative Governance*: As described further by Mr. Gersack, the AGIS initiative's formal project governance processes are incorporated into the AMI project.

4. The FAN

a. FAN Overview

Q. WHAT IS THE FAN?

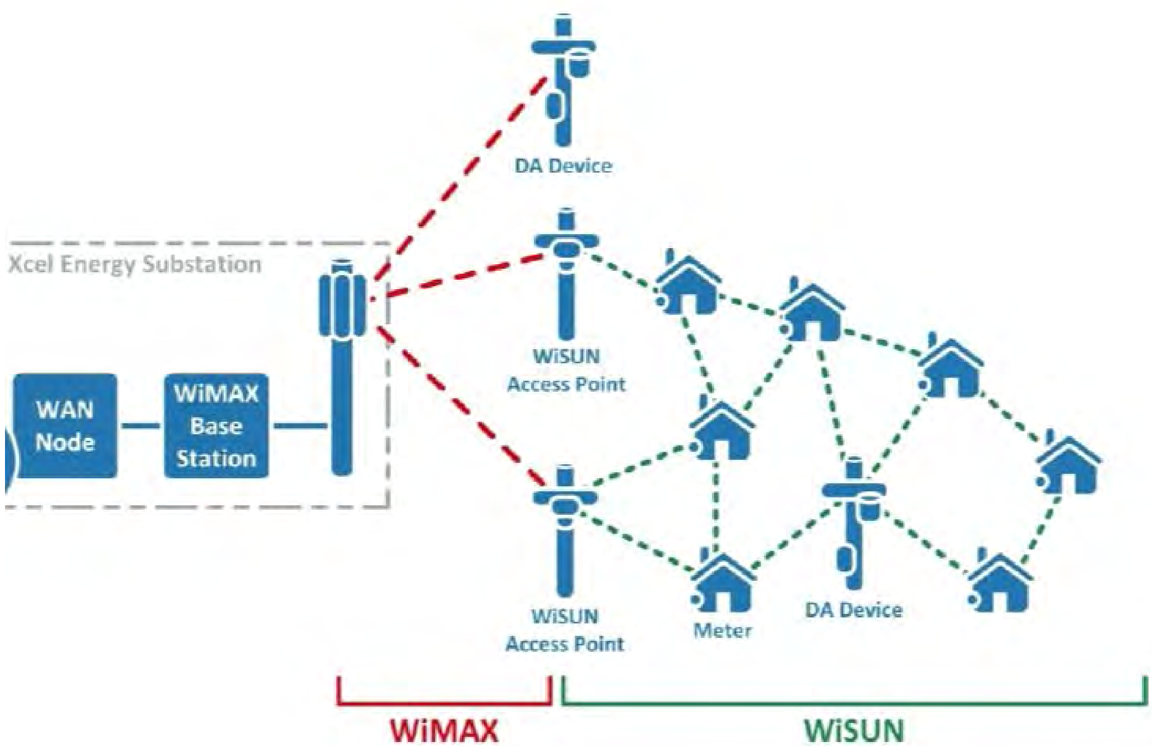
A. The FAN is a private, Company-owned wireless communications network that will leverage our existing Wide Area Network (WAN) and substation infrastructure to securely and reliably address the need for increased communication capacity that arise from the new advanced grid devices, including AMI, FLISR, and IVVO. The primary function of FAN is to enable secure and efficient two-way communication of information and data between our existing substation infrastructure and new or planned intelligent field devices – up to and including meters at customers' homes and businesses. The FAN will provide benefits to all AGIS programs but is designed and built according to the needs of various components, and each has different communication network requirements.

Q. WHAT ARE THE PRINCIPAL TECHNOLOGIES THAT WILL BE USED BY THE FAN?

A. To provide communication between the substation and field devices, the FAN will use two wireless technologies: (1) Wireless Smart Utility Network (WiSUN) mesh network; and (2) a Worldwide Interoperability for Microwave Access (WiMAX) network. These two networks are depicted in Figure 6 below.

Figure 6

WiSUN and WiMAX Networks



Q. DESCRIBE THE COMPANY'S CURRENT COMMUNICATION NETWORK.

A. Xcel Energy's current communication network is the WAN. The WAN provides high-speed, two-way communications capabilities and connectivity in a secure and reliable manner between Xcel Energy's core data centers and its service centers, generating stations, and substations. The Company's current WAN communications network 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.

Q. HOW WILL THE FAN INTERACT WITH THE WAN?

A. The WAN, which resides upstream of the FAN, 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, and facilities such as generating plants and service centers as well as the FAN. The FAN, in turn, will provide the connectivity to intelligent devices installed across the distribution system.

Q. DESCRIBE THE COMPONENTS OF THE WISUN NETWORK.

A. The WiSUN mesh network is the key network structure that will communicate directly with the AMI infrastructure and most Distribution Automation (DA) field devices. The core infrastructure for WiSUN will 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.

An access point is a device that will link the Company's endpoint devices that are enabled with wireless communication modules with the rest of the Company's communication network. The access points will wirelessly connect directly to backhaul (which is an intermediate link in the communications network – WiMAX, in this case) to pass data between the mesh network and the WAN.

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Repeaters are range extenders that are used to fill in coverage gaps where devices would be otherwise unable to communicate. The mesh network design of WiSUN means that additional nodes on the network provide devices more options to communicate with their access point.

Q. DESCRIBE THE COMPONENTS OF THE WIMAX NETWORK.

A. The WiMAX network will consist of two main components: (1) base stations, and (2) customer premise equipment (CPE). I note that "customer" here refers to the Company rather than our electric utility customers. The Company is the "customer" purchasing the WiMAX equipment in this case.

Base stations will serve as the key communication points between the substation WAN and the WiSUN mesh network. At substations there will be a base station with up to three radios that will communicate with the WAN and multi-directionally with CPEs out in the field of operations. Where possible, the base stations at the substations will be mounted on existing poles or structures.

The CPEs will further enable the back office applications to communicate wirelessly with any device accessible to that access point's connections to the mesh network. CPEs will be mounted on distribution poles in the field of operation.

Q. HOW WILL THE WIMAX NETWORKS BE CONNECTED TO AND INTERFACE THE COMPANY'S EXISTING WAN NETWORK?

A. The WiMAX base stations will be connected to the pre-existing WAN connections at the substation, which, in turn, will enable connectivity back to the data center locations. This connection at the substation will be via private fiber or alternate cabling within the substation from the WiMAX base station radios to the routers at the substations which are connected to the WAN. There may be rare instances in which WiSUN devices will be connected directly to the WAN, when WiMAX is not needed.

b. Interrelation of FAN with other AGIS Components

Q. HOW WILL THE COMPONENTS OF THE FAN INTERACT WITH THE OTHER AGIS COMPONENTS?

A. The FAN is the primary communication network for many of the AGIS components to communicate with each other as well as Company's back-office systems.

Q. HOW WILL THE FAN INTERACT WITH THE AMI METERS?

A. The AMI meters will have embedded communication modules that will allow the devices to communicate with the WiSUN network. This will allow data to be transferred between the meters and the AMI head-end application, including interval reads, register reads, voltage information, and power quality data. The FAN will also allow AMI meters to send and receive of commands like power outage notifications. 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.

Q. HOW WILL THE FAN INTERACT WITH FLISR?

A. The FLISR distribution equipment (*i.e.,* feeder-level devices) will have communication modules that will communicate with access points in the mesh network or directly to WiMAX CPEs.

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Q. HOW WILL THE FAN INTERACT WITH THE COMPONENTS OF IVVO?

A. Most devices that control or inform IVVO (such as capacitors, SVCs and power line sensors) will have communication modules that will allow them to communicate as part of the WiSUN mesh network or directly on WiMAX. Through this network, the FAN will allow data to be transferred between the IVVO devices in the field and the ADMS. This will enable the field devices to report their current operating conditions and allow the ADMS to send commands to the devices, thereby enabling the entire system to dynamically react to changing load conditions and voltage levels.

Q. HOW WILL THE FAN INTERACT WITH ADMS?

A. 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.

Q. PLEASE DESCRIBE IN MORE DETAIL HOW THESE SYSTEMS WILL BE INTEGRATED WITH THE FAN.

A. The following applications will be integrated with the FAN:

- *AMI*: The WiSUN 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.

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- *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 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.

c. FAN Benefits

Q. WILL CUSTOMERS DIRECTLY BENEFIT FROM THE DEPLOYMENT OF FAN ALONE?

A. 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. The FAN strategy proposed is tightly coupled with the proposed AMI implementation and similarly enables other technologies that transform the customer experience and create customer value. The reliable, private, secure network capabilities provided by the FAN also enable the end-to-end transport of interval meter data to provide the customer and grid benefits enabled by AMI. FAN also enables the communication for FLISR and thus contributes to the outage restoration capabilities.

Q. HOW DOES THE MESH NETWORK DESIGN OF FAN PROVIDE BENEFITS FOR THE OTHER AGIS COMPONENTS?

A. The mesh network design of FAN provides redundancy and will ensure the overall dependability of communications of the AGIS components. For example, if a device falls on the WiSUN network and can no longer communicate, the mesh configuration of the system will allow that node to be bypassed so other nodes will be unaffected and network communications will continue. Every device on the mesh network will maintain a primary and secondary access point, so that in the case of an access point failure the nodes will automatically route communications to a secondary access point. If the access point outage persists, the entire network will reconstruct itself so that every device will have a primary and secondary access point. The design also calls for access points to be served by multiple WiMAX base stations, so that in the event of a WiMAX base station goes off-line the mesh nodes will still be able to route communications through a different access point and WiMAX base station. In sum, the redundancy of the mesh network design of the FAN will enable endpoint devices to continuously communicate both with each other and with head-end systems.

Q. HOW DOES THE FAN ASSIST THE OTHER AGIS COMPONENTS IN MANAGING OUTAGES?

A. The core infrastructure of both WiMAX and WiSUN will have battery backup as will other devices that are critical for outage operations. This means that the Distribution Control Center will still have visibility into the current status of the grid and remote control capabilities for devices like reclosers. Although AMI meters will not have battery backup, they will have energy storage adequate send "last gasp" messages (that is, a final message transmitted by the

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meter upon detection of an outage) over the FAN to let the head-end system know that particular customers do not have power service. Once those customers have been reenergized, those meters will once again be able to communicate on the FAN and the head-end system will be able to remotely verify that customers have been reconnected. The additional visibility will also aid with the restoration of nested outages[9] by showing that certain customers remain without power even when the surrounding issue was resolved. This will help the control center identify those situations and reduce restoration times.

Q. WHY IS IT IMPORTANT TO IMPLEMENT THE FAN NOW?

A. The FAN communication network is required to support the deployment of AMI meters and will facilitate the operation of FLISR and IVVO. Deploying AMI 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 meter such as driving by or physically reading the meter, both of which would require truck rolls and added labor costs. The primary advantage the FAN provides in terms of efficiency of meter operations is enabling the operate to send remote commands to the meter (such as connect/disconnect), as well as read data as often as required without dispatching a truck and personnel to do so.

Further, without the FAN, the Company would not be able to gain full value from the capabilities of AMI, FLISR, or IVVO. This is because FAN will support the interconnection and communication of the field device

[9] Storms often result in multiple failures. When we repair and reenergize a section, but a subset remains out due to a second fault, that outage is referred to as a "nested" outage.

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

d. FAN Implementation

Q. WHAT WORK IS NECESSARY TO IMPLEMENT THE FAN?

A. FAN implementation requires installation of WiMAX and WiSUN equipment in the field as well as implementation of the necessary software components and IT integration with the Company's other systems.

Q. WHAT WORK IS BUSINESS SYSTEMS UNDERTAKING TO IMPLEMENT THE FAN PROJECT?

A. The specific functions Business Systems provides for FAN implementation include:

- Leading the design of the network systems (WiMAX and WiSUN);
- 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. For WiMAX, Business Systems is primary responsible for the installation of WiMAX base stations at the substations, and Distribution Operations is responsible for the installation of the CPE devices that are located on Distribution poles. Distribution is responsible for installation of the WiSUN devices (APs

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and repeaters), which will be located on Distribution poles. The Business Systems and Distribution budgets reflect this division of responsibility for hardware and installation. Company witness Ms. Bloch discusses the costs associated with the Distribution Operations' participation in the procurement and installation of pole-mounted FAN devices;

- 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.

Q. HOW WILL THE WIMAX INFRASTRUCTURE BE INSTALLED?

A. WiMAX base stations will be primarily installed at substations, with Business Systems responsible for installation using the deployment services provider selected in the RFP process described below, as well as the Company's transmission personnel as needed for work at the substations. Antennas will need to be installed at appropriate heights to provide optimal coverage of the WiMAX signal. Installation can be on existing transmission towers where possible and allowable under safety guidelines. Where there are no suitable transmission structures, a monopole will be erected on which to mount the antennas. The radio equipment will be mounted at ground level at the base of the structure and will connect to the substation's Electronic Equipment Enclosure (EEE) via trenched cabling. The equipment will connect to the WAN in the substation's EEE.

Distribution Operations is responsible for the installation of the CPEs on distribution poles. Ms. Bloch discusses this further in her testimony.

Q. HOW WILL THE WISUN INFRASTRUCTURE BE INSTALLED?

A. WiSUN equipment consists of access points and repeaters. Distribution Operations is responsible for installation of these devices, which will be mounted primarily on distribution poles. Ms. Bloch provides additional installation details in her testimony.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK TO SUPPORT THE FAN IMPLEMENTATION?

A. Yes. To support our TOU pilot, Business Systems and Distribution Operations have begun deploying a limited amount of FAN infrastructure in the same geographic area as the AMI meter deployment (Eden Prairie and Minneapolis). Business Systems has begun to deploy WiMAX base stations in three substations, and Distribution has begun to deploy of access points (APs) and repeaters that will be connected to those base stations. Business Systems has conducted field coverage studies to ensure the FAN will provide adequate coverage for both the TOU as well as full deployment of meters and other devices in those areas.

Q. WHAT IS THE FAN IMPLEMENTATION AND IT INTEGRATION SCHEDULE TO SUPPORT FULL AMI DEPLOYMENT?

A. For any given geography, FAN availability will precede AMI meter deployment by approximately three to six months, to ensure meters will have a fully operational network to use when they are installed. To support this the FAN installation will begin 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 AMI meter deployment, we anticipate FAN deployment will begin in mid-2020 to ensure network readiness when AMI meters and other devices are deployed in mid-2021. Business Systems has already completed limited FAN implementation in connection with the TOU pilot. In addition, Business Systems has already completed initial work for full FAN rollout in Colorado. Full FAN implementation in Minnesota will expand on and enhance these capabilities to meet requirements for deployment in Minnesota.

Q. WILL THE WISUN AND WIMAX NETWORKS BE DEPLOYED THROUGHOUT THE COMPANY'S ENTIRE SERVICE TERRITORY IN MINNESOTA?

A. WiSUN will be deployed throughout the entire network where we are connecting to field devices such as AMI meters. WiMAX is the current primary means of connecting WiSUN to the main WAN backhaul systems, but it is not the only solution that will be deployed. As the Company performs field coverage studies it may deploy other solutions, such as fiber or private LTE, to provide that connectivity.

e. FAN Costs

Q. PLEASE DESCRIBE THE SPECIFIC WORK BUSINESS SYSTEMS WILL UNDERTAKE TO SUPPORT IMPLEMENTATION OF THE FAN IN 2020, 2021, AND 2022.

A. The efforts will include field studies for network coverage in 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 provide the necessary information and data to file for permitting through the FCC for frequency and location of wireless devices. The effort will also include the planning and organizing of all labor required to build out and install the network devices throughout the geography of the implementation.

Q. WHAT BUSINESS SYSTEMS CAPITAL AND O&M COSTS ARE NECESSARY FOR FAN IMPLEMENTATION DURING THE TERM OF THE MYRP IN THIS CASE?

A. The table below provides the Business Systems capital additions and O&M costs for FAN implementation for 2020 through 2022.

Table 32

FAN Capital Additions – Business Systems State of MN Electric Jurisdiction (Includes AFUDC)(Dollars in Millions)			
AGIS Program	2020	2021	2022
FAN	$5.4	$15.9	$42.0

Table 33

FAN O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
FAN	$0.0	$2.1	$1.1

Q. WAS BUSINESS SYSTEMS PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECAST FOR THE FAN?

A. Yes. Business Systems was responsible for developing the forecast for both the WiSUN and WiMAX components of the FAN. Therefore, I describe the forecast development process for these aspects in more detail below. Ms.

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Bloch discusses the costs associated with Distribution's participation in the procurement and installation of pole-mounted FAN devices.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE WISUN FORECAST.

A. As previously noted, Business Systems employs standard processes and procedures for selecting technologies to be deployed in the Company's environment, as well as the execution of large capital projects. These standard processes are being utilized for deployment of the FAN, as follows:

- *Product Selection*: The Company awarded a contract for the WiSUN mesh network in 2017 to Itron after an extensive and thorough competitive RFP process. 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 primary input the RFP award.
- *Project and Initiative Governance*: The AGIS initiative's formal project governance processes are incorporated into the FAN project.

Q. PLEASE PROVIDE AN OVERVIEW OF THE PROCESS FOR DEVELOPING THE WIMAX FORECAST.

A. The Company's standard forecast development processes were followed, as set forth below:

- *Product Selection*: An RFP was issued and awarded for the WiMAX primary vendor in 2015. That portion of the project is in the deployment process. The Company awarded a contract for this part of the AGIS solution in 2017. In conjunction with the RFP for the AMI

Software selection, Itron was also selected in 2017 for the WiSUN mesh aspects of the FAN. This process ensured the most optimal solution for the Company's needs was selected and the Company negotiated a contract with reasonable costs.

- *Project and Initiative Governance*: The AGIS initiative's formal project governance processes are incorporated into the FAN project.

(1) FAN Capital Forecast

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE FAN CAPITAL FORECAST?

A. The FAN forecast has two key components: (1) labor; and (2) hardware. Ms. Bloch discusses the costs associated with Distribution's participation in the procurement and installation of pole-mounted FAN devices.

Q. HOW DID THE COMPANY DERIVE THE LABOR PORTION OF THE FAN FORECAST?

A. The labor costs were derived utilizing pricing gained from industry benchmarks and reviewed with other utilities and industry research organizations such as EPRI. In addition, our labor estimates are based on our experience and work that has already been completed for FAN implementation. Business Systems has leveraged spend information to date, for both FAN rollout in Colorado and the limited deployment of FAN in Minnesota to support the TOU pilot, to estimate the future costs associated with full deployment in Minnesota. While specific Minnesota requirements are yet to be determined, the work performed in Colorado provides a reasonable point of reference for labor estimates for most general functional and non-functional work areas supporting Minnesota. 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, RF design, configuration and testing, planning engineering, program management, and network services.

Q. HOW DID THE COMPANY DERIVE THE HARDWARE PORTION OF THE FAN FORECAST?

A. The hardware portion of our FAN budget was derived from prices included in contracts resulting from RFP processes. Xcel Energy has standards for all hardware that is deployed in the field. These standards define hardware for which the Company has industry benchmarked, negotiated pricing. On an enterprise-wide basis, Xcel Energy issued four RFPs for FAN hardware and deployment services. For this project, the Company issued separate equipment and installation RFPs, so there were two RFPs for WiMAX and two for WiSUN.

Q. HOW DID THE COMPANY SELECT THE VENDORS FOR THE FAN TECHNOLOGY?

A. The Company conducted four RFPs related to the FAN technology. The following vendors were selected:

- WiMAX technology – Airspan was awarded the technology contract and Council Rock was awarded the reseller contract.
- WiMAX deployment service provider – Council Rock was awarded the deployment service contract.
- WiSUN Mesh technology – Silver Spring Networks (now Itron) was award the equipment contract which includes associated software.
- WiSUN deployment service provider – Silver Springs (now Itron) was awarded the deployment services contract.

Although these were four separate RFPs, a combined summary of the selection processes and results are provided as Trade Secret Exhibit___(DCH-1), Schedule 12.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WIMAX TECHNOLOGY.

A. Xcel Energy issued an RFP in 2015 to select a vendor to provide the WiMAX technology and equipment. Responses were received from three different companies. Xcel Energy evaluated these vendors and responses on a number of factors including:

- Technical performance;
- Operational performance;
- System long-term survivability;
- Adequacy of security capabilities;
- Warranty and support;
- Manageability with operational model;
- Ability to design mesh systems;
- Ability to implement;
- Ability to meeting scope and schedule;
- Acceptability of business terms and conditions;
- Industry experience;
- Adequacy of support system; and
- Pricing.

In 2016 Xcel Energy selected Airspan and began contract negotiations, which were finalized in 2016. Since Airspan does not sell direct to customers, Council Rock was selected as the company that would sell Airspan technology solutions to the Company. Contract details include product pricing for base station radios, CPEs, antennas, and all associated hardware required for installation.

Q. WHY DID XCEL ENERGY SELECT AIRSPAN AS THE VENDOR FOR THE WIMAX TECHNOLOGY?

A. The primary factors in the decision were:

- Favorable pricing;
- Ability to meet technical requirements; and
- Industry experience with other utilities and similar type communication systems.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WIMAX DEPLOYMENT SERVICES.

A. Xcel Energy issued an RFP in 2015 to select a vendor to provide implementation services for the WiMAX solution. Key requirements included ability to provide adequate resources for deployment plans, experience deploying similar technology, familiarity with solution provider and other project management related experience. Responses were received from two different companies. Xcel Energy evaluated these vendors and responses on a number of factors including those listed above, as well as references from other utilities.

In 2016 Xcel Energy selected Council Rock and began contract negotiations, which were finalized in 2016. Contract details include product pricing for installation of base station radios, CPEs, antennas, and all associated hardware.

Q. WHY DID XCEL ENERGY SELECT COUNCIL ROCK AS THE VENDOR FOR THE WIMAX DEPLOYMENT SERVICES?

A. The primary factors in the decision were:

- Council Rock's experience with implementing similar solutions for other utilities;
- Council Rock's demonstrated expertise in the technology and what the Company is deploying; and
- Council Rock's relationship with Airspan in procurement and installation.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WISUN TECHNOLOGY.

A. Xcel Energy issued an RFP in 2015 to select a vendor to provide the WiSUN technology and equipment. Responses were received from three different companies. Xcel Energy evaluated these vendors and responses on a number of factors including those listed above. Xcel Energy also allowed each vendor to come to Xcel facilities in the summer of 2016 to deploy their technology with their own resources and demonstrate their product's performance against specific requirements in the RFP. Those tests were conducted by the vendors with Xcel Energy's assistance. Results for each vendors test were provided to them but not shared with other vendors. The results were also used for internal scoring in determining the vendor awarded the technology/product contract.

In 2016 Xcel Energy selected Silver Springs (now Itron) and began contract negotiations. Contract negotiations were finalized at the end of 2016. The contract includes detailed product pricing, licensing pricing based on end device counts for many of the software specific applications, optional pricing for a number of potential software solutions, services pricing and other related parts and services for future potential deployments.

Q. WHY DID XCEL ENERGY SELECT SILVER SPRINGS (NOW ITRON) AS THE VENDOR FOR THE WISUN TECHNOLOGY?

A. The primary factors in the decision were:

- Leadership in the marketplace for requirements similar to Xcel Energy's in the RFP;
- Performance in the testing against Xcel Energy requirements (met all of the testing requirements); and
- References from other utilities that implemented the same technology.

Q. DESCRIBE THE PROCESS USED TO SELECT THE VENDOR FOR THE WISUN DEPLOYMENT SERVICES.

A. Xcel Energy issued an RFP in 2016 to select a vendor to provide installation services including planning, coverage mapping, network performance planning, device installation layout, device installation planning and support service requirements. Responses were received from two different companies. Xcel Energy evaluated these responses on a number of factors including: experience, price, ability to deliver, and industry references

In 2016 Xcel Energy selected Silver Springs (now Itron) and began contract negotiations. Contract negotiations were finalized in late 2016 and included in the overall Silver Springs (now Itron) contract.

Q. WHY DID XCEL ENERGY SELECT ITRON AS THE VENDOR FOR THE WISUN DEPLOYMENT SERVICES?

A. The primary factors in the decision were:

- Experience with the technology and requirements defined in the RFP;
- References from other utilities;
- Input from EPRI and other industry groups involved in technology deployment; and
- Favorable pricing.

(2) FAN O&M Forecast

Q. WHAT ARE THE PRIMARY COMPONENTS OF BUSINESS SYSTEMS' FAN O&M FORECAST?

A. The primary components of Business Systems' FAN O&M forecast include the work necessary for FAN implementation as well as ongoing field support for devices deployed, hardware maintenance (patches and firmware upgrades), technical support for the network, and Network Operations Center (NOC) support for monitoring the network. In other words, these cost forecasts encompass the incremental work that will be necessary to support FAN implementation and ongoing maintenance and support.

Q. HOW DID BUSINESS SYSTEMS DERIVE THE FORECAST FOR FAN O&M?

A. The FAN O&M forecast was developed based on FAN vendor contracts, existing internal support team estimates of the work required, and industry benchmarking information gathered from other utilities and industry organization such as EPRI. Each AGIS component has an internal IT team responsible for project delivery. Our forecasts for labor costs related to AMI are based on estimates from these team members, who have previous experience with similar systems implementations and support models, including FAN implementation in Colorado. I note that there could be future sourcing decisions for different AGIS components as additional requirements are identified. The Company would use its existing sourcing processes to manage additional O&M requirements in a cost-effective manner.

(3) FAN Contingency

Q. DO THE BUSINESS SYSTEMS FAN FORECASTS INCLUDE CONTINGENCY AMOUNTS?

A. Yes. The Business Systems FAN budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 45 percent. Using contingencies is consistent with project planning practices, especially for large projects that implement new technologies and require major changes to enterprise IT systems. Mr. Gersack discusses the overall AGIS project contingencies in his testimony. In the AMI section above, I discuss the reasons for including contingency amounts in the AMI budget that are applicable to the FAN as well. This is due to the integrated nature of deployment and implementation of these technologies.

Q. GIVEN THE EARLIER CONTINGENCY DISCUSSION, CAN YOU HIGHLIGHT THE PRIMARY REASONS FOR INCLUDING CONTINGENCY AMOUNTS WITH RESPECT TO THE FAN?

A. Yes. While we have based our budget estimates on all known design and installation details, there remain uncertainties with respect to specific deployment of the FAN devices and unknowns that may develop through the installation phase. For the FAN, the primary for contingency is to recognize there may be situations where the primary solution being deployed may not work, for example in remote areas at edge of grid. Further, there may be a change in deployment counts of sites or devices or other situations that could not be anticipated in the initial plan. Contingencies also recognize that there may be a sudden change in viable technology or identification of a security risk or vulnerability that we would not be able to anticipate at this time.

(4) FAN Expenditures 2020-2029

Q. WHAT ARE THE BUSINESS SYSTEMS CAPITAL EXPENDITURE AND O&M FORECASTS FOR THE FAN FOR 2020 THROUGH 2029?

A. The tables below provide the Business Systems capital expenditure and O&M forecasts for the FAN for 2020 through 2029.

Table 34

FAN Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
FAN	$11.5	$31.1	$36.8	$3.8	$0.0
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 35

FAN O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
FAN	$0.0	$2.1	$1.1	$0.2	$8.2
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

(5) FAN Cost Summary

Q. WHY IS BUSINESS SYSTEMS' FAN FORECAST REASONABLE FOR CUSTOMERS TO SUPPORT?

A. The FAN is a foundational component of AGIS, which is a long-term strategic initiative to transform our electrical distribution system to enhance security, efficiency, and reliability, to safely integrate more DERs, including those that are customer owned, and to enable improved customer products and services. The FAN will provide communications between the advanced grid devices, including the AMI meters, enabling business operations efficiencies, and a better customer experience to empower informed energy decisions. The IT components described above are necessary to implement AMI, and the AMI IT forecast is reasonable in enabling technologies that improve customer products and services.

f. Minimization of Risk of Obsolescence for FAN

Q. HOW WILL THE FAN TECHNOLOGIES SELECTED BY THE COMPANY PROTECT AGAINST OBSOLESCENCE?

A. The WiSUN mesh technology is constantly being validated, refreshed, updated, and enhanced by industry organizations (WiSUN alliance and IEEE standards bodies) to ensure it is staying abreast of technology changes and requirements. The Company participates in the WiSUN alliance and ensures it technology partners are involved and leading efforts in both the Wi-SUN alliance and the IEEE standards bodies with other technology vendors and manufacturers. The Wi-SUN alliance continues to drive the incorporation of additional communications and security standards into the certification process. Currently, a number of AMI vendors have received WiSUN PHY certification. In 2019, a number of AMI vendors will receive WiSUN FAN

1.0 certification. Next will be Border Router certification and hopefully in 2022, Wi-SUN FAN 2.0 certifications are targeted. Company strategy is to continue to drive the AMI vendor community toward WiSUN certifications as they progress in the industry. Company strategy is to deploy WiSUN capable networks with continued industry standards based technological extensions which meet Company's robust security and performance objectives. In other words, as vendors update technologies, we are working with them to increase interoperability.

g. Alternatives to FAN

Q. WHAT ALTERNATIVES TO FAN DID THE COMPANY EVALUATE?

A. The FAN RFP processes and vendor selections described above were the result of an enterprise-wide effort that began in 2010 to identify an appropriate communications solution to support advanced grid capabilities. The principal alternative to the FAN for supporting AMI is the use of cellular carrier solutions. 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. However, these alternatives would not match the features and capabilities of the FAN network. Below I discuss the efforts we have undertaken since 2010 to inform our decisions on the FAN strategy, and provide the background for our assessment of the FAN compared to the alternatives.

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Q. PLEASE OUTLINE THE COMPANY'S EFFORTS TO DEVELOP A COMMUNICATIONS SOLUTION FOR THE ADVANCED GRID.

A. The Company 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, a detailed study of potential network efforts to support operations for the Company was developed and reviewed with business units 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). This strategy was refined over a two-year period and involved direct input and collaboration with key engineers from all business units, including Finance, Capital Asset Accounting, and Security.

The Company then began developing initial plans for the FAN in 2012-2013 through an organized effort with external vendors comparing currently deployed network solutions and comparing that to what will be needed for communications with emerging technologies such as ADMS, AMI, FLISR, and IVVO 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.

Q. HOW DID THE WORK YOU DESCRIBE ABOVE INFORM THE DEVELOPMENT OF THE COMPANY'S FAN STRATEGY?

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

- Leverage Xcel Energy owned assets such as Wide Area Network 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;
- 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 2013-2015 the Company prepared and executed detailed RFIs and RFPs for the network solutions to support the business applications as discussed above.

The Company's proposed the FAN, composed of WiMAX and WiSUN components, is also 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 Company actively participated with industry standards organizations and alliances – such as EPRI and IEEE – to ensure that our requirements and assumptions are aligned with the standards and products being deployed throughout the industry. In choosing FAN technology, we have 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 WiSUN and WiMAX networks are standards based network solutions that conform to IEEE standards.

Q. PLEASE DISCUSS THE COMPANY'S FAN PROPOSAL COMPARED TO USE OF A CELLULAR CARRIER SOLUTION FOR ADVANCED GRID COMMUNICATIONS.

A. The principal alternative to the FAN for supporting AMI is the use of cellular carrier solutions. If this was used for replacing the RF Mesh, this 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 alternative would cause the Company to incur substantial monthly and annual expenses.

In particular, when comparing cellular carrier solutions and the FAN, the Company determined that device costs were fairly similar but monthly and annual expenses were considerably higher with the use of public cellular network. Other key decision criteria such as security, reliability, and support costs all weighed into the decision to choose the FAN. Also factoring into our decision is consideration of latency requirements. By latency, we refer 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. This creates an extended period of time (latency) that does not meet the Company requirements for some applications.

Cellular backhaul also would not fully support the Company's requirements for peer-to-peer requirements in all cases. Peer-to-peer requirements are associated with devices in a local setting being able to talk to each other to provide situational awareness to what is happening on the feeder or grid, and help make decisions near instantaneously without needing to communicate with applications at a data center or central office. If cellular was used to replace WiMAX (*i.e.*, Cellular backhaul from APs top data center) the same concern would apply as well as reducing the advantages of planned distributed computing at the substations to manage data traffic and provide local computing capabilities.

Q. WHAT ARE THE SECURITY ADVANTAGES ASSOCIATED WITH THE PRIVATE FAN NETWORK AS COMPARED TO A PUBLIC CELLULAR NETWORK?

A. A private network allows the Company to better control the integrity of the devices on its network and the data exchanged with those devices. Through the exchange of digital certificates, as well as other controls, Company determines and authorizes each device before allowing it to use the FAN. As does any utility, Company utilizes many public communications circuits for the backhaul of voice and data communications. Security threats, however, are more prevalent in networks with a higher number of points of entry. The Company's FAN network will carry communications traffic for literally millions of end-devices, span its entire service territory and experience constant device moves/adds/changes and upgrades. Company strategy to reduce cyber threat vulnerability footprint is to manage its own FAN.

Q. PLEASE DISCUSS THE COMPANY'S FAN PROPOSAL COMPARED TO AN ALTERNATIVE DEDICATED AMI NETWORK SOLUTION FOR ADVANCED GRID COMMUNICATIONS.

A. By definition, and AMI-dedicated network solution would only allow connectivity between AMI devices. When comparing this option to the FAN, the Company determined that it will be more functional and is preferable to have a FAN network that 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.

Q. WHAT DID THE COMPANY CONCLUDE AFTER EVALUATING DIFFERENT COMMUNICATIONS NETWORK SOLUTIONS?

A. The Company concluded that virtually none of the communication network alternatives could match the features and capabilities of the FAN network. A

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summary comparison of the FAN capabilities to the alternative options is provided in Table 36 below.

Table 36
Comparison of Network Communications Solutions

Feature/ Requirement	FAN Mesh	Cellular	Dedicated AMI Network	Comments
Two-way Communications	●	●	●	All can do two-way communications.
Peer-to-Peer	●	◔	◕	Less clear how this would be accomplished with cellular.
Multi-purpose	●	◕	◔	Only FAN Mesh can support all potential use cases at Xcel Energy.
Latency Requirements	●	●	◕	If set up correctly each could meet requirements known today for latency.
Security	●	◑	●	Dedicated networks provide more secure traffic not travelling over public networks.
Dedicated Traffic	●	◔	◕	The network would be fully dedicated to Xcel Energy traffic.
Priority Traffic	●	◔	●	Dedicated networks allow for priority traffic routing with Xcel Energy traffic being the top priority.
O&M Costs Impact (run state)	●	◔	◑	Higher monthly costs for data traffic using cellular and higher support costs per device for dedicated AMI network.
Resiliency	●	◑	◑	Fewer unplanned outages with mesh network as it heals itself. The more devices on the mesh the more resilient.

Legend				
Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

5. FLISR

a. FLISR Overview

Q. WHY IS IT INTEGRATION IMPORTANT FOR IMPLEMENTATION OF FLISR?

A. The advanced application FLISR will rely on accurate power flow calculations to determine the power flow at points on the grid where sensor information does not exist. As such, they require integration with the core ADMS systems. FLISR must be integrated with the ADMS core applications and other critical systems to provide its intended benefits to the Company's customers.

Q. WHAT WORK IS BUSINESS SYSTEMS UNDERTAKING WITH RESPECT TO FLISR?

A. The work Business Systems will undertake with respect to FLISR is as follows:

- Leading the design of the system components;
- Configuration of the required software and hardware;
- Building and installation of any required interfaces;
- Designing and integrating security into all aspects of FLISR;
- Thorough unit, system, and end-to-end testing; and|
- User Acceptance Testing (UAT) with the Distribution business resources.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK TO SUPPORT FLISR IMPLEMENTATION?

A. Yes. FLISR implementation has been planned on an enterprise-wide basis, and work to test functionality was completed for Colorado in 2019. In Minnesota, Business Systems will support testing of FLISR on the feeders selected by the Distribution organization. As discussed in Ms. Bloch's testimony, as part of the installation of ADMS, FLISR will be deployed to a

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small two-feeder area in South Minneapolis in 2020 to validate the ADMS capabilities. Business Systems has engaged in work to support this FLISR testing, which will be conducted in the second quarter of 2020. I note that this limited testing of FLISR is included in the costs for ADMS, which the Company proposes to continue recovering through the TCR Rider. FLISR implementation costs for 2020 and beyond are proposed for inclusion in base rates.

Q. PLEASE DESCRIBE THE WORK BUSINESS SYSTEMS WILL UNDERTAKE TO SUPPORT IMPLEMENTATION OF FLISR IN 2020, 2021, AND 2022.

A. As discussed in Ms. Bloch's testimony, the Company proposes to implement FLISR on 206 additional feeders between 2021 and 2028, and Distribution will install the FLISR equipment. Business Systems will support this FLISR implementation by adding and conditioning field devices to support FLISR functionality. Business Systems will also perform testing to support this implementation.

b. FLISR Costs

Q. WHAT BUSINESS SYSTEM CAPITAL ADDITIONS AND O&M COSTS ARE NECESSARY FOR IT INTEGRATION FOR FLISR DURING THE TERM OF THE MYRP IN THIS CASE?

A. Table 37 below provides the capital additions for IT integration for FLISR for 2020 through 2022. Table 38 shows that there are no IT O&M costs for FLISR integration during the term of the MYRP.

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Table 37

FLISR Capital Additions – Business Systems State of MN Electric Jurisdiction (Includes AFUDC)(Dollars in Millions)			
AGIS Program	2020	2021	2022
FLISR	$0.3	$0.4	$0.6

Table 38

FLISR O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
FLISR	$0.0	$0.0	$0.0

Q. WAS BUSINESS SYSTEMS PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECASTS FOR FLISR?

A. No. However, Business Systems is responsible for the integration of the Sensor Management System (SMS) for Aclara sensors into ADMS, and for managing the integration of the FLISR sub-application with ADMS. Although Ms. Bloch provides a discussion of the forecast process with respect to the FLISR advanced application and its related field devices in her Direct Testimony, I discuss the Aclara SMS below.

Q. WHAT IS THE ACLARA SMS FOR FLISR?

A. The Aclara SMS is software which provides control and reporting on sensors across the Company's distribution system. It also acts as a virtual RTU, providing the ability to integrate the sensor data with the SCADA system. The sensors and SMS will be used in conjunction with each other to support FLISR. FLISR requires that the substation relay provide certain signals in order to communicate to the ADMS to begin automatic locating of the fault and subsequent restoration. The Company's current substation standard requires a specific make and model of relay which many of the Company's substations do not have, so these sensors provide a low cost alternative that can provide that telemetry. Because the Aclara SMS software is currently used for other purposes across the Company's distribution system, no new software is needed to implement FLISR.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE IT CAPITAL FORECAST TO IMPLEMENT FLISR?

A. The FLISR IT capital forecast is primarily composed of labor costs for the work described above.

Q. HOW DID THE COMPANY DEVELOP THESE COST ESTIMATES?

A. The Company developed labor estimates primarily using actual labor costs for the design and implementation of the FLISR functionality testing described above as part of ADMS implementation.

Q. PLEASE DESCRIBE THE FLISR CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. The Business Systems FLISR budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 24 percent. A significant portion of the FLISR IT work and cost is to develop templates which provide the computer screen interface for managing field devices used for FLISR functions. Each device requires a corresponding template. Base Templates are created as generic templates across a product family. These are used as the starting point to create Subtype Templates, which include the attribute variations needed by each device subtype in the product family. Significant work is required for each Subtype Template build.

The amount of re-use of the Base Template to create the Subtype Templates is estimated, but not precisely known until the detailed build work begins. We have included a contingency for FLISR implementation due to this unknown.

c. FLISR Expenditures 2020-2029

Q. WHAT ARE THE BUSINESS SYSTEMS CAPITAL EXPENDITURE AND O&M FORECASTS FOR FLISR FOR 2020 THROUGH 2029?

A. The tables below provide the Business Systems capital expenditure and O&M forecasts for FLISR for 2020 through 2029.

Table 39

FLISR Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
FLISR	$0.4	$0.5	$0.7	$2.9	$3.4
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 40

FLISR O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
FLISR	$0.0	$0.0	$0.0	$0.1	$0.1
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Q. WHY IS BUSINESS SYSTEMS' FLISR FORECAST REASONABLE FOR CUSTOMERS TO SUPPORT?

A. FLISR is an advanced grid component that will enable significant reliability improvements for our customers, and operational efficiencies for the Company. Overall, implementing FLISR allows the Company to more efficiently restore power with the use of fewer resources and will improve the customer reliability experience. The Business Systems work will provide for the implementation of FLISR and integration with the advanced grid technologies, enabling these benefits for our customers and the Company. The Business Systems FLISR forecast is reasonable based on the details provided above.

6. IVVO

a. IVVO Overview

Q. WHY IS IT INTEGRATION IMPORTANT FOR IMPLEMENTATION OF IVVO?

A. The advanced application IVVO will rely on accurate power flow calculations to determine the power flow at points on the grid where sensor information does not exist. As such, they require integration with the core ADMS systems. IVVO must be integrated with the ADMS core applications and other critical systems to provide its intended benefits to the Company's customers.

Q. WHAT WORK IS BUSINESS SYSTEMS UNDERTAKING WITH RESPECT TO THE IVVO?

A. The work Business Systems will undertake with respect to IVVO is as follows:

- Leading the design of the system components;
- Configuration of the required software and hardware;
- Building and installation of any required interfaces;

- Designing and integrating security into all aspects of IVVO;
- Thorough unit, system, and end-to-end testing;
- User Acceptance Testing (UAT) with the Distribution business resources.

Q. HAS BUSINESS SYSTEMS ALREADY PERFORMED WORK TO SUPPORT THE IVVO IMPLEMENTATION?

A. Yes. IVVO implementation has been planned on an enterprise-wide basis, and work to test functionality was completed for Colorado in 2019. In Minnesota, Business Systems will support testing and implementation of the IVVO on the feeders selected by the Distribution organization. As discussed in Ms. Bloch's testimony, as part of the installation of ADMS, the Company will implement IVVO on the seven feeders at one substation in Southeast Minneapolis. Business Systems has engaged in work to support this IVVO testing, which will be conducted in the second quarter of 2020. I note that this limited testing of IVVO is included in the costs for ADMS, which the Company' proposes to continue recovering through the TCR Rider. The implementation costs for wider IVVO deployment are proposed for inclusion in base rates.

Q. PLEASE DESCRIBE THE WORK BUSINESS SYSTEMS WILL UNDERTAKE TO SUPPORT IMPLEMENTATION OF IVVO IN 2020, 2021, AND 2022.

A. As discussed in Ms. Bloch's testimony, the Company proposes to implement IVVO at 13 substations between 2021 and 2024. Distribution will install the IVVO equipment, the Company will capture data and configure equipment, and then tune ADMS models. Business Systems will support this IVVO implementation by adding and conditioning field devices to support IVVO

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functionality and will perform testing to support this expansion. Business Systems will also implement the Grid Edge Management System (GEMS) software for the secondary static VAr compensator (SVC) devices that are part of the IVVO implementation, and will complete IT integration of the IVVO advanced sub-application with ADMS.

b. IVVO Costs

Q. WHAT BUSINESS SYSTEM CAPITAL ADDITIONS AND O&M COSTS ARE NECESSARY FOR IT INTEGRATION FOR IVVO DURING THE TERM OF THE MYRP IN THIS CASE?

A. Table 41 below provides the capital additions for IT integration for IVVO for 2020 through 2022. Table 42 shows that there are no IT O&M costs for IVVO integration during the term of the MYRP.

Table 41

IVVO Capital Additions – Business Systems State of MN Electric Jurisdiction (Includes AFUDC)(Dollars in Millions)			
AGIS Program	2020	2021	2022
IVVO	$0.0	$1.7	$1.9

Table 42

IVVO O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)			
AGIS Program	2020	2021	2022
IVVO	$0.0	$0.0	$0.0

Q. WAS BUSINESS SYSTEMS PRIMARILY RESPONSIBLE FOR DEVELOPING THE FORECASTS FOR IVVO?

A. No. However, Business Systems was responsible for developing the forecast for the GEMS software and for managing the integration of the IVVO advanced sub-application with ADMS. Although Ms. Bloch provides a discussion of the forecast process with respect to the IVVO advanced application and its related field devices, I discuss GEMS below.

Q. PLEASE DESCRIBE THE GEMS SOFTWARE THE COMPANY HAS SELECTED TO SUPPORT THE IVVO FIELD DEVICES.

A. The GEMS software was included in the package from the vendor supplying the SVC devices. As discussed in Ms. Bloch's testimony, the Company began an RFP process to select an SVC vendor in the second quarter of 2018. As a result of the RFP, the Company selected Varentec's Edge of Network Grid Optimization (ENGO) unit as the winning bidder for the SVC devices. The GEMS software to manage and control the SVC devices was included in the package. Business Systems will deploy the GEMS software for management and control of the ENGO SVC devices. The Company will host the server in-house for IVVO deployment.

Q. WHAT ARE THE PRIMARY COMPONENTS OF THE IVVO IT CAPITAL FORECAST TO IMPLEMENT THIS SOFTWARE?

A. The IVVO IT capital forecast has three key components: hardware, software, and labor.

Q. WHAT HARDWARE IS NEEDED FOR IVVO IMPLEMENTATION FOR BUSINESS SYSTEMS?

A. The additional hardware necessary for AMI implementation consists of computing components used for data processing and storage to support IVVO services. Additional servers are needed due to the increased volume of data and processes necessary to implement IVVO capabilities.

Q. HOW DID THE COMPANY DERIVE THE HARDWARE PORTION OF THE AMI IT FORECAST?

A. Xcel Energy has standards for all hardware that is deployed in our data centers. These standards define hardware for which the Company has industry benchmarked, negotiated pricing. Based on these standards, the hardware estimates were derived utilizing the hardware requirements of the applications and applying standard pricing.

Q. HOW DID THE COMPANY DEVELOP THE COST FORECAST FOR IVVO SOFTWARE COSTS?

A. Pricing for the IVVO software is provided in the contract with Varentec, selected through the RFP process noted above. Pricing is consistent with industry benchmarks and our review with other utilities and industry research organizations such as EPRI. These benchmarks drove the negotiations with the selected vendor. Varentec provided budgetary quotes for their ENGO device licensing based on a cloud-based approach and an in-house server based approach. The in-house approach, described above for the AMI forecast, was used to develop cost estimates, consistent with the Company's security requirements.

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Q. HOW DID THE COMPANY DEVELOP THE FORECAST FOR THE CAPITAL LABOR COSTS?

A. Our forecast includes both internal and external labor. External labor costs are based on the contract pricing described above. The internal labor forecast is based on our experience and work that has already been completed for IVVO implementation. Business Systems has leveraged spend information to date, for both IVVO rollout in Colorado and the limited deployment in Minnesota for testing purposes, to estimate the future costs associated with full deployment in Minnesota.

Q. ARE THERE OTHER COSTS INCLUDED IN THE BUSINESS SYSTEMS CAPITAL FORECAST FOR IVVO?

A. Yes. There are additional project management costs that are include in the IVVO capital forecast. For Business Systems, these include labor costs for delivery and execution leadership and security.

Q. HOW DID THE COMPANY DEVELOP THESE PROJECT MANAGEMENT COST FORECASTS?

A. These capital costs were developed using contract pricing for the external project management work, and labor estimates for the work necessary to support IVVO integration efforts described above. These costs were derived based on evaluation of prior work performed in Colorado, which provides a reasonable point of reference for labor estimates for most general functional areas supporting Minnesota.

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Q. WHAT ARE THE PRIMARY COMPONENTS OF BUSINESS SYSTEMS IVVO O&M COSTS?

A. The primary components of Business Systems IVVO O&M costs include ongoing hardware support, data storage, annual software maintenance, application support, and labor for software support.

Q. HOW DID BUSINESS SYSTEMS DERIVE THE IVVO O&M FORECAST?

A. The IVVO O&M forecast was developed based on vendor quotes, existing internal support team estimates of the work required, and industry benchmarking information. Each AGIS component has an internal IT team responsible for project delivery. Our forecasts for labor costs related to AMI are based on estimates from these team members, who have previous experience with similar systems implementations and support models.

Q. PLEASE DESCRIBE THE IVVO CONTINGENCY AMOUNTS INCLUDED IN THE FORECAST.

A. The Business Systems IVVO budget forecast for the period 2020-2025 includes capital contingency amounts of approximately 10 percent. A significant portion of the IVVO IT work and cost is to develop templates which provide the computer screen interface for managing field devices used for IVVO functions. Each device requires a corresponding template. Base Templates are created as generic templates across a product family. These are used as the starting point to create Subtype Templates, which include the attribute variations needed by each device subtype in the product family. Significant work is required for each Subtype Template build.

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The amount of re-use of the Base Template to create the Subtype Templates is estimated, but not precisely known until the detailed build work begins. We have included a contingency for IVVO implementation due to this unknown.

c. IVVO Expenditures 2020-2029

Q. WHAT ARE THE BUSINESS SYSTEMS CAPITAL EXPENDITURE AND O&M FORECASTS FOR IVVO FOR 2020 THROUGH 2029?

A. The tables below provide the Business Systems capital expenditure and O&M forecasts for IVVO for 2020 through 2029.

Table 43

IVVO Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
IVVO	$0.0	$1.9	$2.2	$4.3	$0.0
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 44

IVVO O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
IVVO	$0.0	$0.0	$0.0	$0.1	$0.0
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

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Q. WHY IS BUSINESS SYSTEMS' IVVO FORECAST REASONABLE FOR CUSTOMERS TO SUPPORT?

A. IVVO will enable automated capabilities to optimize the operation of the distribution voltage regulating and VAr control devices to reduce electrical losses, electrical demand, and energy consumption, and provides increased distribution system capacity to host DER. The Business Systems work will provide for the implementation of IVVO and integration with the advanced grid technologies, enabling these benefits for our customers and the system. The Business Systems IVVO forecast is reasonable based on the details provided above.

7. *AGIS IT Overall Costs and Implementation*

Q. OVER WHAT TIME PERIOD WILL THE FOUNDATIONAL COMPONENTS OF AGIS BE IMPLEMENTED?

A. The Company began implementation of the foundational components of AGIS in 2019, and implementation of AMI, the FAN and IVVO will be substantially completed in 2024. FLISR implementation will be accomplished over a longer time period, through 2028.

Q. WHAT ARE THE TOTAL IT INTEGRATION COSTS FOR THE AGIS COMPONENTS?

A. The tables below show the total capital expenditure and O&M IT integration costs, by component, for 2020-2029.

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED

Table 45

AGIS Capital Expenditures – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	$11.4	$6.5	$10.0	$5.7	$0.9
FAN	$11.5	$31.1	$36.8	$3.8	$0.0
FLISR	$0.4	$0.5	$0.7	$2.9	$3.4
IVVO	$0.0	$1.9	$2.2	$4.3	$0.0
Total	$23.3	$40.0	$49.7	$16.7	$4.3
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Table 46

AGIS O&M – Business Systems NSPM – Total Company Electric (Dollars in Millions)					
AGIS Program	2020	2021	2022	2023-2024	2025-2029*
AMI	$4.2	$13.1	$9.1	$15.2	$51.5
FAN	$0.0	$2.1	$1.1	$0.2	$8.2
FLISR	$0.0	$0.0	$0.0	$0.1	$0.1
IVVO	$0.0	$0.0	$0.0	$0.1	$0.0
Total	$4.3	$15.3	$10.2	$15.5	$59.8
Period may include additional assumptions, including inflation and labor cost increases, that are not part of the capital budget in periods 2020-2024.					

Q. WHAT IS YOUR RECOMMENDATION FOR THE COMMISSION WITH RESPECT TO THE BUSINESS SYSTEMS COMPONENTS OF THE AGIS INITIATIVE?

A. I recommend that the Commission approve our request to recover the Business Systems costs of the capital investments and O&M expense for the foundational components of AGIS that we propose to implement during the 2020-2022 term of the MYRP. Our proposal includes full AMI implementation, IVVO and FLISR as part of our broader grid resiliency efforts, and the FAN components necessary to support AMI and the advanced grid applications. We also recommend that the Commission certify these projects to provide the opportunity for the Company to request recovery of costs for 2023 and later in subsequent rider filings. Approval of the costs necessary to implement the AGIS initiative will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. I recommend that the Commission approve the Business Systems capital and O&M budget presented in this rate case. Our planned capital investments are managed appropriately and established to address aging technology, cyber security, customer experience, enhanced capabilities, and emerging demand for the Company. Certain major projects, such as our investment in the AGIS initiative, will bring the distribution grid and the Company into the future. The budgets we propose are a reasonable representation of the activities we will undertake on behalf of the Company and ultimately our service to customers through 2022 and beyond.

Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

A. Yes, it does.

DAVID C. HARKNESS

Chief Information Officer • Senior IT Executive • Chief Technology Officer • Senior Vice President IT

PROFILE

Talented and accomplished senior IT executive and corporate officer with consistent record of success in promoting corporate growth through effective management of technology operations. Special expertise in change management, turnaround leadership, digital transformation, multi-sourcing, technology development. Proven ability to lead Customer Marketing, Product Development, Sales, Brand activities. Familiar with supporting M&A activities. Adept at building relationships with business stakeholders.

IT Governance • Strategic Planning • Enterprise Business Transformation • Turnaround Operations
Service Delivery • Project/Program Management • Relationship Management • Cost/Budget Control
Technology Development • Succession Planning • Enterprise Infrastructures/Architectures
Six Sigma/Lean/ITIL • Compliance • Outsourcing • SAP/ERP Deployment • Shared Services

PROFESSIONAL EXPERIENCE

XCEL ENERGY, Minneapolis, MN 2009 - Present

Senior Vice President Customer Solutions (2019 – Present)
Lead the Customer Solutions organization for the Commercial & Industrial, Residential and Small Business–focused customer segments. C&I portfolio currently represents 500,000 customers and 60 percent of Xcel Energy revenue, while the Residential and Small Business segment represents roughly 3.5 million customers and 40 percent of Xcel Energy revenue. This includes HomeSmart, Xcel Energy's national non-regulated home warranty business, Economic Development, Transportation and EVs, Digital Channel Management, Product Development, DSM Product Management and Regulatory & Strategy, Renewable Product Management. By combining his business and technology leadership experiences, Dave helps create and drive a transformed digital customer experience. Utilizing strategic partnerships, he leads Xcel Energy toward a product and services portfolio helping develop connected communities, advanced home and business energy solutions, and further enable the electrification of the Transportation industry.

Senior Vice President; Chief Information Officer (2009 – 2019)
Responsible for all information technology development, operations and governance, cyber security functions, and Xcel Energy's overall business continuity program. Drives innovation and transformation by leveraging technology to create business value for $11B Gas and Electric energy company operating in 8 states. Administer $500M combined budget and supervise 900 direct and indirect reports, including senior IT leadership team. Manage strategy development

and ensure alignment with corporate goals. Build and maintain strategic partner relationships, primarily IBM, Accenture, Dell, Motorola, PWC. Direct infrastructure operations, including data / voice communications, service levels, and security.

- Drove $400M SAP Deployment (Productivity Through Technology program) across enterprise including all 4 subsidiaries.
- Increased deployment capacity 300% through Digital Transformation program.
- Restructured primary sourcing contract spend by $25M annually; representing a 25% reduction.
- Developed 10-yr IT strategic Roadmap including Business Unit plans, Platform Risk Assessment, Cyber Security Requirements and Enterprise Architecture principles and reference architectures.

PNM RESOURCES, Albuquerque, NM 2003 - 2009

Vice President; Chief Information Officer (2006-2009)
Oversee all technology management and development for $2.6B energy company with 4 subsidiaries in Southwest. Administer $70M combined budget and supervise 260 direct and indirect reports, including executive management team. Manage strategy development and ensure alignment with corporate goals. Identify needs and implement improvements. Evaluate new technologies and determine ROI for purchase vs. build strategies. Build and maintain partner and vendor relationships. Direct infrastructure operations, including data / voice communications, service levels, and security.

- Reduced spending 20% and headcount 40% over 18-month period.
- Increased deployment capacity 400% and internal client satisfaction 30% by implementing new portfolio management process.

Executive Director, Business Transformation (2006)
Managed organizational development, corporate training, Six Sigma Black Belt and Lean process improvement, and M&A operations. Supervised staff of 25.

- Implemented enterprise-wide competency model that included performance management, leadership development, and roundtable review. Launched online / classroom training program.

Executive Director, Business Process Outsourcing, First Choice Power (2005-06)
Directed major outsourcing project for $600M subsidiary. Project encompassed call center, field offices, bill printing, remittance processing, and various system conversions. Managed provider relationship. Created program plan and operating model. Supervised staff of 20.

- Brought call center and bill printing online in 2 months and remittance processing in 3 months.
- Facilitated >$4M in annualized savings through successful completion of initiative.

Executive Aide to CEO, President, & Chairman (2004-05)
Completed 6-month program of corporate officer mentorship. Attended board meetings, long-range strategic planning sessions, investor/regulator meetings and more. Actively involved in corporate governance and ethics review and planning sessions.

MCLEODUSA, Cedar Rapids, IA 1996 - 2003
Director, Enterprise Applications Development
Supervised application development, business analysis for $1B telecom company. Supervised staff of more than 120 developers. Administered $20M budget.

MCI COMMUNICATIONS, Cedar Rapids, IA 1991 - 1996
Manager, Business Analysis
Developed and led software projects for 800 Card marketing group and Intelligent Services Platform. Supervised 8 senior-level analysts and administered $8M+ budget.

CAREER NOTES: Previously held position of **Software Engineer** at ROCKWELL INTERNATIONAL (1985-1991). Wrote patented algorithm for robot manufacturing equipment.

ADDITIONAL EXPERIENCE

STATE OF NEW MEXICO, Santa Fe, NM 2005 - 2009
State Commissioner, Information Technology Commission
Appointed by governor to commission responsible for state information architecture and strategic information technology plan.

EDUCATION

BS in Computer Science/ BA in Applied Mathematics, The University of Iowa, Iowa City, IA

TRAINING & DEVELOPMENT

Utility Executive Course, The University of Idaho
Merger Week, Kellogg School of Business, Northwestern University

CURRENT & PAST AFFILIATIONS

Chair, Board of Directors, BestPrep, an organization driven to improve business and financial literacy of MN youth

Board of Directors, Minnesota High Tech Association, organization of Minnesota based businesses driving to improve the technology literacy and maturity in the state of Minnesota

Chair, EEI (Edison Electric Institute) Technology Advisory Council; Group of EEI and AGA (American Gas Association) CIOs designated to collaborate on key technical and business challenges facing utility Industry.

Member of EEI Executive Advisory Committee CIO group; consult on technology policy; advises Energy CEOs

Advisory Board University of Idaho Utility Executive Course – Premier Utility industry executive development program since 1952

CIO Advisory Board for IBM's Global Infrastructure

Volunteer for EarthDay; Feed my Starving Children; Holidazzle Parade; Big Brothers/Big Sisters

Chair, College Success Network Board of Directors 2006-2010
Vice Chair, PNM Resources Foundation Board of Trustees 2008-2009
PNM Resources Speakers Bureau and Community Crew 2004-2009

FOR PROFIT BOARD SERVICE

Director, PayGo Board of Directors
Director, First Choice Power Board of Directors

AWARDS / PUBLICATIONS / SPEAKING ENGAGEMENTS

Orbie Twin Cities CIO of the Year 2018
ComputerWorld Magazine's 100 Premier IT Leaders 2008
Author/Contributor - Managing Your IT Department as a Business: Leading CTOs and CIOs on Assessing Client Needs, Driving IT Costs Down, and Measuring Performance; Aspatore, September, 2009
Radio Interview – CIOTalkRadio
CIO Magazine / Martha Heller CIO Paradox
Multiple Interviews/Publications for EnergyCentral, EnergyBiz, Intelligent Utility, Five Point Partners, Utility CIO Knowledge Conference, CIO Global Forum

Capital Investment Additions
NSPM

Category	Project Name	WBS Level 2 #	Classification	Addition Amount 2020	2021	2022	Date
Enhance Capabilities	ITC- BUS SYS WIND Blazing Star2 MN	A.0001702.009	Electric General Plant	(247,338)			12/31/2020
Enhance Capabilities	ITC- BUS SYS WIND Freeborn MN	A.0001704.008	Electric General Plant	(371,540)			12/15/2020
Enhance Capabilities	ITC-BUS SYS Dakota Range WIND SD	A.0001707.008	Electric General Plant		(346,394)		12/31/2021
AGIS	ADMS SW MN	D.0001723.004	Electric General Plant	(43,165,009)			4/30/2020
Enhance Capabilities	Sub Asset Mgmt SW MN	D.0001728.004	Electric Intangible Plant			(5,583,004)	12/31/2022
Aging Technology	Emptoris SW MN-10708	D.0001732.011	Common Intangible Plant				12/31/2023
Cyber Security	NSPM C Corp Sec Furn	D.0001781.001	Common General Plant	(232)	(0)		1/1/2025
Cyber Security	NSPM E Corp Sec Ntwk	D.0001781.010	Electric General Plant	(21)			1/1/2025
Cyber Security	Security Projects - Electric -	D.0001781.035	Electric General Plant	(119,405)	(5,852)	(287)	1/1/2025
Cyber Security	Security Projects - Common - MN	D.0001781.036	Common General Plant	(282)	(14)	(1)	1/1/2025
Aging Technology	Peoplesoft Upgrade SW MN	D.0001792.040	Common Intangible Plant			(28,635,543)	12/31/2022
Aging Technology	Purch Sub Frame Relay Equip ND	D.0001797.007	Electric General Plant	3,591			12/31/2020
Emergent Demand	BS-Fcst-BD-SW-CM-M	D.0001804.085	Common Intangible Plant	(9,067,834)	(14,745,822)	(12,216,205)	12/31/2024
Cyber Security	Security Tech Refresh SW MN	D.0001807.001	Common Intangible Plant	(5,334,002)	(11,636,100)	(8,265,066)	12/31/2023
Aging Technology	2018 EMS Infra Refresh MN	D.0001821.304	Electric General Plant		(247,000)		12/31/2021
Aging Technology	2020 Planned MDT Refresh MN	D.0001821.413	Common General Plant		(2,434,870)		12/31/2021
Aging Technology	Real Property Asset Mgmt Upgra	D.0001826.005	Common Intangible Plant				12/31/2023
Enhance Capabilities	Purch Synchrophasor Net HW MN	D.0001826.370	Electric General Plant	(980,891)			4/30/2020
Aging Technology	Purch CRS Tech Stack HW MN	D.0001839.400	Common General Plant	(250,000)			12/31/2020
Aging Technology	Purch VOIP MN	D.0001840.021	Common General Plant	(399,996)			12/31/2020
AGIS	PURCH FAN HW CM COMM MN	D.0001900.049	Common General Plant	(6,813,182)	(19,966,725)	(24,796,788)	12/31/2024
AGIS	AGIS Advanced Metering SW MN	D.0001901.004	Electric Intangible Plant	(3,798,298)			12/31/2020
AGIS	AGIS Meter Data Mgmt (MDMS) SW MN	D.0001901.008	Electric Intangible Plant	(8,249,299)			12/31/2020
AGIS	AMI-BS-NSPM-MN Full AMI	D.0001901.040	Electric Intangible Plant	(3,312,399)	(6,581,018)	(4,698,678)	1/1/2025
AGIS	AMI-BS-NSPM-MN-TOU-CRS-Billing Modu	D.0001901.054	Electric Intangible Plant	(924,511)			12/31/2020
AGIS	Purch AGIS FLISR El Comm MN	D.0001902.029	Electric General Plant	(363,194)	(466,905)	(466,919)	1/1/2025
AGIS	AGIS Integrated Volt Var (IVVO) SW	D.0001904.004	Electric Intangible Plant		(1,896,843)	(1,917,915)	12/31/2024
AGIS	AGIS-BS-Capital-Comm-Contingency-NS	D.0001908.018	Common General Plant			(27,925,189)	12/31/2022
AGIS	AGIS-BS-Capital-E-Comm-Contingency-	D.0001908.025	Electric General Plant			(274,223)	12/31/2024
AGIS	AGIS-BS-Cap-SW-Cont-AMI-NSPM	D.0001908.053	Electric Intangible Plant			(5,460,955)	1/1/2025
AGIS	AGIS-BS-Cap-SCom-Cont-IVVO-NSPM	D.0001908.061	Electric General Plant			(255,715)	1/1/2025
Aging Technology	2020 Oracle SW MN	D.0002003.015	Common Intangible Plant		(1,656,526)		12/31/2020
Aging Technology	2021 Oracle SW MN	D.0002003.019	Common Intangible Plant		(1,656,526)		12/31/2021
Aging Technology	2022 Oracle SW MN	D.0002003.023	Common Intangible Plant			(1,170,900)	12/31/2022
Cyber Security	Ent DataBase Security Ph4 SW MN-107	D.0002008.015	Common Intangible Plant	(375,927)			3/20/2020
Aging Technology	Purch WAN HW MN-BSPRJ0001167	D.0002011.001	Common General Plant	(8,251,371)	(15,823,270)	(10,792,247)	12/31/2023
Aging Technology	Purch Facility IT Investments HW MN	D.0002021.001	Common General Plant		(2,771,384)		12/31/2021
Aging Technology	TAMS Replacement SW MN	D.0002025.001	Electric Intangible Plant			(1,576,550)	12/31/2022
Customer	Customer Identity Access SW MN-1068	D.0002028.004	Common Intangible Plant	(1,509,750)			4/20/2020
Enhance Capabilities	BUD-Application Virtualization HW M	D.0002029.005	Common General Plant			(2,500,002)	12/31/2022
Aging Technology	Cash Management System SW MN	D.0002032.001	Common Intangible Plant		(599,666)		12/31/2021
Enhance Capabilities	Customer Engagement Platform SW MN	D.0002036.001	Common Intangible Plant			(353,400)	12/31/2022
Customer	CEC-Cust Service Console SW MN-1070	D.0002037.001	Common Intangible Plant		(9,524,378)		12/20/2021
Customer	CEC-Homesmart Ph2 SW MN-10722	D.0002037.011	Common Intangible Plant	(372,984)			12/18/2020
Customer	CEC-Builders Call SW MN-10723	D.0002037.016	Common Intangible Plant	(633,950)			12/31/2020
Aging Technology	DEMS Ph4 HW MN-10756	D.0002038.004	Electric General Plant	(12,380,272)			12/31/2020
Aging Technology	ITC-Purch DEMS HW MN	D.0002038.010	Electric General Plant	(3,391,272)			12/31/2020
Aging Technology	eGRC Phase IV SOx Corp Com SW MN-10	D.0002041.001	Common Intangible Plant	(594,172)			12/20/2020
Aging Technology	eGRC FERC Compliance SW MN	D.0002041.005	Common Intangible Plant			(371,208)	12/31/2022
Aging Technology	eGRC Ph IV SOX SW MN-10764	D.0002041.013	Common Intangible Plant	(227,201)			12/20/2020
Enhance Capabilities	BUD-Enterprise Operational HW MN	D.0002045.005	Common General Plant		(1,333,332)		12/31/2021
Emergent Demand	BUD-IT Blanket Core Tech HW MN	D.0002060.001	Common General Plant		(254,000)	(558,764)	12/31/2024
Aging Technology	Meridium Upgrade SW MN	D.0002063.001	Common Intangible Plant	(1,913,002)			12/31/2020
Enhance Capabilities	Remote Branch Office SW MN	D.0002071.001	Common Intangible Plant	(827,642)			12/31/2020
Enhance Capabilities	Safety Observation SW MN	D.0002073.001	Electric Intangible Plant		(286,026)		12/31/2021
Enhance Capabilities	BUD-BSPRJ1134 SAP Data Gov SW MN	D.0002074.001	Common Intangible Plant				12/31/2023
Aging Technology	TWR SW MN-10713	D.0002078.004	Electric Intangible Plant	(1,583,980)			4/30/2020
Enhance Capabilities	Video Conf SW MN	D.0002082.001	Common Intangible Plant			(2,619,555)	12/31/2022
Aging Technology	BUD-Windows OS Upgrade SW MN	D.0002083.001	Common Intangible Plant			(2,163,726)	12/31/2022
Enhance Capabilities	Software Asset Mgmt SW MN-10729	D.0002084.008	Common Intangible Plant	(1,017,437)			12/31/2020
Enhance Capabilities	Tririga Mobile SW MN-10730	D.0002084.017	Common Intangible Plant	(504,448)			12/31/2020
Aging Technology	2022 Remittance SW MN	D.0002086.001	Common Intangible Plant			(200,608)	12/31/2022
Enhance Capabilities	Data Analytics SW MN	D.0002091.001	Common Intangible Plant			(4,428,288)	12/31/2024
Aging Technology	Product Office Enable SW MN	D.0002103.001	Common Intangible Plant				12/31/2023
Aging Technology	ITSM Modernization SW MN	D.0002104.001	Common Intangible Plant			(3,113,151)	12/31/2022
Enhance Capabilities	ITAM Mod SW MN	D.0002105.001	Common Intangible Plant				12/31/2023
Aging Technology	Purch VOIP Refresh HW MN	D.0002106.001	Common General Plant	(223,105)	(452,885)	(376,078)	12/31/2023
Aging Technology	NMS 2x SW MN	D.0002107.001	Electric Intangible Plant			(6,364,439)	12/31/2022
Aging Technology	Purch Rugged Tablet HW MN	D.0002109.001	Common General Plant	(357,508)	(642,492)		12/31/2021
Aging Technology	Commodity Mgmt Sys SW MN	D.0002110.001	Common Intangible Plant			(1,463,026)	12/31/2022
Aging Technology	SubTran Portal SW MN	D.0002111.001	Electric Intangible Plant		(639,916)		12/31/2021
Enhance Capabilities	Purchase Power SW MN	D.0002113.001	Electric Intangible Plant	(1,306,773)			12/31/2020
Aging Technology	Trans Change Asset SW MN	D.0002119.001	Electric Intangible Plant			(1,036,460)	12/31/2022
Aging Technology	Site Scope SW MN	D.0002126.001	Common Intangible Plant	(240,648)			12/31/2020
Aging Technology	2022 Planned Printer HW MN	D.0002127.001	Common General Plant			(250,000)	12/31/2022
Aging Technology	Bus Obj SW MN	D.0002133.001	Common Intangible Plant		(455,045)		6/30/2021
Enhance Capabilities	Mobile App Mod SW MN	D.0002136.001	Common Intangible Plant	(363,624)			12/31/2020
Aging Technology	Workforce One 2020 Lic MN	D.0002138.005	Common Intangible Plant	(88,510)			12/31/2020
Aging Technology	2023 Planned Printer HW MN	D.0002144.001	Common General Plant				12/31/2023
Aging Technology	2021 Planned Printer HW MN	D.0002145.001	Common General Plant		(125,000)		12/31/2021
Cyber Security	Purch SPAM Filter HW MN	D.0002146.005	Common General Plant		(200,000)		12/31/2021
Enhance Capabilities	Micro Monitor SW MN	D.0002147.001	Common Intangible Plant	(84,030)			12/31/2020
Aging Technology	DRMS PH 2 SW MN	D.0002149.001	Common Intangible Plant		(2,339,677)		12/31/2021
Aging Technology	Tech Lic 2020 SW- MN	D.0002150.001	Common Intangible Plant	(509,232)			12/31/2020
Aging Technology	Tec Lic 2021 SW-MN	D.0002151.001	Common Intangible Plant		(503,072)		12/31/2021
Aging Technology	Tec Lic 2022 SW-MN	D.0002152.001	Common Intangible Plant			(503,345)	12/31/2022
Aging Technology	Tec Lic 2023 SW-MN	D.0002153.001	Common Intangible Plant				12/31/2023
Cyber Security	Purch 2020 Sec Cam HW MN	D.0002154.001	Common General Plant	(175,000)			12/31/2020
Cyber Security	Purch 2022 Sec Cam HW MN	D.0002156.001	Common General Plant			(575,000)	12/31/2022
Aging Technology	Purch 2021 Net Ref HW MN	D.0002157.001	Common General Plant		(1,000,000)		12/31/2021

Northern States Power Company
Capital Investment Additions

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Aging Technology	Purch 2022 Net Ref HW MN	D.0002158.001	Common General Plant			(1,625,000)	12/31/2022
Aging Technology	Purch 2023 Net Ref HW MN	D.0002159.001	Common General Plant				12/31/2023
Aging Technology	2023 Oracle SW MN	D.0002160.001	Common Intangible Plant				5/1/2023
Aging Technology	OSI Soft PI Ent Agree SW MN	D.0002161.001	Common Intangible Plant				8/31/2023
Enhance Capabilities	Diagnostic Center 5 SW MN-10725	D.0002163.003	Electric Intangible Plant			(603,508)	12/31/2022
Aging Technology	Sharepoint Nuclear EL SW MN only	D.0002164.002	Electric Intangible Plant	(1,236,689)			12/31/2020
Aging Technology	Purch Teradata Hadoop HW MN	D.0002169.001	Common General Plant		(785,228)		12/31/2021
Cyber Security	Security Svc 2022 SW MN	D.0002171.001	Common Intangible Plant			(124,213)	12/31/2022
Aging Technology	2021 EMS Refresh HW MN	D.0002172.001	Electric General Plant		(202,313)		12/31/2021
Aging Technology	2022 EMS Refresh HW MN	D.0002173.001	Electric General Plant			(250,000)	12/31/2022
Aging Technology	BUD-Purch MT Security Servers Nuc M	D.0002174.001	Electric General Plant		(3,286,580)		12/31/2021
Aging Technology	SAP Purge Archive SW MN	D.0002176.001	Common Intangible Plant		(1,346,202)		12/31/2021
Aging Technology	IIB Lic ESB SW MN-10742	D.0002184.002	Electric Intangible Plant	(1,511,097)			12/31/2020
Aging Technology	ITC-Purch IIB ESB EL HW MN	D.0002184.006	Electric General Plant	(36,896)			12/31/2020
Enhance Capabilities	CRS Voice Agent SW MN-10753	D.0002199.003	Common Intangible Plant	(351,006)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 EMS Infra HW MN	D.0002208.001	Electric General Plant		(127,328)		12/31/2021
Aging Technology	BUD-ITC-Purch 2020 Handheld Mobile	D.0002209.001	Common General Plant		(62,140)		6/30/2021
Aging Technology	BUD-ITC-Purch 2020 IT INFS Ref HW M	D.0002210.001	Common General Plant	(1,893,750)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 Planned PC HW MN	D.0002211.001	Common General Plant	(2,069,650)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 Plan Server HW M	D.0002212.001	Common General Plant	(750,000)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 Storage HW MN	D.0002213.001	Common General Plant	(1,700,000)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 UnPlan PC HW MN	D.0002215.001	Common General Plant	(600,000)			12/31/2020
Aging Technology	BUD-ITC-Purch 2020 Unplan Server HW	D.0002216.001	Common General Plant	(250,000)			12/31/2020
Aging Technology	BUD-ITC-Purch 2021 Unplan PC HW MN	D.0002217.001	Common General Plant		(600,000)		12/31/2021
Aging Technology	BUD-ITC-Purch 2022 Unplan PC HW MN	D.0002218.001	Common General Plant			(750,000)	12/31/2022
Aging Technology	BUD-ITC-Purch 2023 Plan PC HW MN	D.0002219.001	Common General Plant				12/31/2023
Aging Technology	BUD-ITC-Purch 2023 Unplan PC HW MN	D.0002220.001	Common General Plant				12/31/2023
Aging Technology	BUD-ITC Active Directory 2020 SW MN	D.0002221.002	Common Intangible Plant	(396,684)			12/31/2020
Aging Technology	BUD-ITC-Cust Care IVR SW MN	D.0002223.002	Common Intangible Plant		(1,913,772)		12/31/2021
Enhance Capabilities	BUD-ITC Cust Care Stop Start SW MN	D.0002224.002	Common Intangible Plant			(748,196)	12/31/2022
Aging Technology	BUD-ITC-Purch Data Center HW MN	D.0002225.005	Common General Plant				3/31/2023
Aging Technology	BUD-ITC-DMZ SW MN	D.0002226.002	Common Intangible Plant			(1,748,318)	12/31/2022
Aging Technology	BUD-ITC-GIS SW MN	D.0002227.002	Common Intangible Plant				12/31/2023
Aging Technology	BUD-ITC Integrated Energy Mgmt SW M	D.0002228.002	Electric Intangible Plant				12/31/2023
Aging Technology	BUD-ITC-Internet Explorer SW MN	D.0002229.002	Common Intangible Plant			(1,692,602)	12/31/2022
Aging Technology	BUD-ITC-Purch 2021 Plan Converged H	D.0002230.001	Common General Plant		(2,462,500)		12/31/2021
Aging Technology	BUD-ITC-Purch 2022 Plan Converged H	D.0002231.001	Common General Plant			(2,337,500)	12/31/2022
Aging Technology	BUD-ITC-Purch 2023 Plan Converged H	D.0002232.001	Common General Plant				12/31/2023
Aging Technology	BUD-ITC-Purch 2021 Plan PC HW MN	D.0002233.001	Common General Plant		(2,187,494)		12/31/2021
Aging Technology	BUD-ITC-Purch 2022 Plan PC HW MN	D.0002234.001	Common General Plant			(2,450,007)	12/31/2022
Aging Technology	BUD-ITC-SCCM 2021 SW MN	D.0002235.001	Common Intangible Plant		(522,287)		12/31/2021
Aging Technology	BUD-ITC-Software Defined Data SW MN	D.0002236.002	Common Intangible Plant		(8,439,181)		12/31/2021
Enhance Capabilities	BUD-ITC-TRIRIGA Construction SW MN	D.0002238.002	Common Intangible Plant			(682,376)	12/31/2022
Aging Technology	BUD-ITC-VDI 2020 SW MN	D.0002239.001	Common Intangible Plant	(1,307,332)			12/31/2020
Enhance Capabilities	BUD-ITC-Integrated Financial SW MN	D.0002242.002	Common Intangible Plant				12/31/2023
Customer	BUD-CXT NSPMN	D.0002246.001	Common Intangible Plant	(13,064,636)	(13,588,109)	(12,096,288)	12/31/2022
Enhance Capabilities	BUS SYS Purch Net Equip Crown Wind	A.0001705.006	Electric General Plant	(326,893.46)			7/1/2020
Enhance Capabilities	ITC Purch BUS SYS Net Eq Jeffers WI	A.0001721.002	Electric General Plant	(255,846.65)			11/30/2020
Enhance Capabilities	ITC-Purch BUS SYS Net Eq Comm WIND	A.0001722.002	Electric General Plant	(254,442.97)			11/30/2020

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O&M Costs by Cost Element Account
NSPM Electric

Posting Accou	Description	2016 Actuals	2017 Actuals	2018 Actuals	2019 July Forecast	2020 Forecast	2021 Forecast	2022 Forecast
5540001	Productive Labor	9,445,867.32	11,489,995.52	14,392,160.77	20,013,380.25	26,618,582.03	27,438,069.42	28,245,647.27
5540180	Premium Time Labor	3,664.02	4,407.80	3,534.97	2,321.89			
5540185	Other Compensation Accruals	101,105.02	1,077.65					
5540220	Labor Overtime	156,096.03	180,120.97	231,961.35	82,998.61			
5540260	Other Compensation	16,479.69	13,086.27	28,707.15	16,721.42			
5540270	Welfare Fund				1,150.63			
5600001	Contract Labor	5,702,636.57	7,369,602.20	6,604,799.37	7,647,724.41	7,779,023.98	17,405,908.89	12,932,487.81
5600006	Consulting Professional Services Other	3,812,047.49	1,879,969.09	2,160,301.27	1,563,284.01	1,414,567.55	1,396,813.96	1,403,070.47
5600016	Consulting Professional Eng and Design			3,699.90				
5600021	Consulting Professional Services Legal	2,348.69	11,138.18	96,418.71	80,059.43			
5600031	Consulting Legal Regulatory	(6.45)						
5600041	Outside Vendor Contract	33,000.79	109,172.39	216,815.85	215,683.14	84,985.51	84,985.52	84,985.47
5600051	Outside Services Customer Care	924.77	236.89	1,729.25	198.20			
5600066	Materials	225,406.40	175,940.20	153,838.55	102,931.94	66,971.51	67,119.25	67,268.09
5600069	Service Consumption			2,298.41	2,889.04			
5600070	Material - Direct Purchase			21.61				
5600073	Material Small Cap Purchases	15.90						
5600091	Print and Copy Cost - Other	4,358.66	7,065.35	10,794.62	5,520.10	4,294.61	4,294.61	4,294.61
5600106	Equipment Maintenance	898,701.26	858,020.06	466,173.02	649,508.39	1,109,648.23	1,138,725.21	1,168,610.64
5600116	IT Hardware Maintenance	1,327,486.65	1,367,195.26	2,449,287.07	3,207,812.24	4,415,084.19	6,014,404.92	5,540,848.42
5600121	IT Hardware Purchases	283,075.98	255,842.36	388,866.39	219,516.48	229,586.25	237,827.35	246,269.20
5600126	Software License Purchase - Perpetual	395,562.71	388,398.81	766,721.33	402,055.31	515,519.51	535,916.07	557,128.41
5600131	Software License Purchase - Term	1,838,213.72	2,697,602.55	3,103,080.36	3,832,168.82	4,418,479.60	4,941,501.30	5,382,050.63
5600136	Software Maintenance	16,742,281.24	18,319,353.96	19,912,536.46	20,808,379.47	27,047,680.10	28,289,357.96	28,878,350.24
5600141	Network Services	424,470.01	305,101.08	710,233.46	270,114.88	406,460.31	406,456.33	406,288.96
5600146	Network Voice	3,455,268.09	3,710,632.45	3,501,184.26	3,157,451.10	2,416,631.87	2,426,543.25	2,389,662.89
5600151	Network Data	4,973,833.21	4,486,014.98	5,996,223.92	11,108,871.60	12,356,769.47	12,355,940.41	12,315,150.01
5600156	Network Telecommunication	8,507,920.09	8,623,754.37	6,232,358.54	1,175,169.01	181,761.22	181,991.50	180,531.24
5600161	Network Radio	1,593,947.30	814,638.80	1,680,717.57	1,698,628.97	539,918.98	539,918.85	539,918.97
5600166	Mainframe Services	753,878.57	760,457.86	1,071,116.24	1,262,353.05	1,614,724.91	1,477,614.80	1,477,614.80
5600171	Distributed Systems Services	9,377,993.58	3,718,164.42	2,943,690.32	2,318,769.18	2,107,676.24	2,180,520.86	2,254,847.55
5600176	Application Development and Maintenance	9,740,307.36	8,560,964.78	7,751,183.49	9,806,799.24	9,252,251.15	9,279,977.26	8,990,494.18
5600186	Software - ASP	1,404,737.15	1,101,757.07	733,196.26	1,195,689.89	1,716,581.41	1,757,717.85	1,815,822.59
5600191	Employee Expenses Airfare	107,549.38	110,909.06	156,094.23	191,583.06	180,136.03	183,308.00	186,710.63
5600196	Employee Expenses Car Rental	11,128.32	10,012.97	12,080.71	13,394.85	18,969.96	19,333.29	19,712.81
5600201	Employee Expenses Taxi and Bus	9,845.45	11,867.22	15,570.00	16,413.71	18,204.17	18,510.44	18,819.54
5600206	Employee Expenses Mileage	26,536.61	24,175.29	19,246.46	19,361.76	16,302.29	16,642.41	16,987.00
5600211	Employee Expenses Conf Seminar Trng	85,239.68	136,435.39	75,503.50	85,748.55	110,574.35	113,705.09	115,745.30
5600216	Employee Expenses Hotel	131,614.53	160,492.84	197,294.94	169,974.81	159,597.04	162,233.88	164,975.40
5600221	Employee Expenses Meals	70,528.41	54,983.52	77,853.59	56,239.38	61,651.10	62,586.78	63,546.39
5600226	Employee Expenses Meals Non-Employee	13,209.46	18,986.68	17,492.32	10,540.43	1,992.90	2,021.37	2,049.60

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5600231	Employee Expenses Parking	34,515.04	23,213.79	44,353.20	55,468.73	73,027.39	73,237.04	73,454.51
5600236	Employee Expenses Per Diem	645.33	6,405.12	(113.40)	18.00			
5600241	Employee Expenses Safety Equipment	18,740.05	9,900.05	3,390.25	2,986.35	8,844.08	8,851.56	8,851.56
5600246	Employee Expenses Other	(276,570.85)	72,057.96	58,502.73	61,313.38	42,881.83	42,992.50	43,828.86
5600251	Employee Expense Personal Communication	482,044.55	559,814.79	640,067.13	201,994.58	372,445.66	373,482.95	374,748.26
5600256	Office Supplies	47,921.19	24,466.16	37,807.19	54,440.03	71,887.37	71,969.31	72,052.03
5600261	Workforce Administration Expense	49.69	278.14	35.99				
5600271	Safety Recognition	33,895.88						
5600276	Life Events	2,743.48	2,315.96	3,758.57	2,256.04	942.47	942.47	948.18
5600291	Transportation Fleet Cost	77,020.77	39,452.41	485.00	77,613.19	170,972.06	170,972.06	170,972.06
5600296	Janitorial - Routine				2,951.81	5,903.63	5,903.63	5,903.63
5600306	Fire Life Safety Maintenance		1,467.80	4,218.62	792.92			
5600311	General Interior Exterior Maintenance	50.00	290.33	2,035.83	3,991.68			
5600316	Use Costs	5.37		1,828.06	855.29			
5600336	Trash Removal Costs		50.00					
5600341	Water Use Costs			358.08	204.92			
5600351	Moves Adds Changes	12,112.08	13,929.48	91.17	34,382.58	6,411.88	6,488.33	6,564.78
5600381	Rent - Space	786.50	192.83	169.46	3,541.06	7,082.13	7,082.14	7,082.13
5600382	Rent - Equipment	4,041.48	255.71	1,868.22	1,118.97	1,888.57	1,888.57	1,888.57
5600436	Postage	32,677.84	35,926.93	32,882.30	30,222.07	32,001.75	32,619.19	33,253.76
5600516	Advertising - General			55.48				
5600546	Customer Program - Advertising		58.86					
5600566	Customer Program - Non-Recoverable		99.00					
5600591	Dues - Professional Association	130,296.10	19,037.47	34,348.43	50,129.84	54,320.93	54,575.77	54,830.83
5600596	Dues - Utility Association Other	(1,096.99)	1,500.00	1,000.00	3,000.00			
5600601	Dues - Utility Association		11,650.16		6,556.49			
5600721	Environmental Permits and Fees			198.86				
5600726	License Fees and Permits	4,731.54	56,567.77	12,385.72	5,819.45			
5600778	Removal Salvage	(2,337.25)		(2,079.93)				
5600781	O and M Credits - Other	(5,687.62)						
5600861	Shared Asset Costs	19,965,797.23	24,528,479.80	23,814,823.56	29,537,058.80	38,418,314.92	37,610,104.49	45,733,295.76
5600866	Shared Assets - Owning Co Credit	(27,026,164.78)	(33,166,416.75)	(25,379,661.93)	(27,799,858.36)	(33,870,939.56)	(33,671,599.04)	(34,453,235.86)
5600871	Other	182,335.74	3,539.58	90,363.58	(5,190,565.89)			
5600896	Online Information Services	602,382.50	525,656.25	784,942.39	1,242,211.92	1,045,419.90	1,082,030.27	1,126,956.64
5600951	Purchasing Overhead Expense		(88.48)					
5610000	External Settlement Labor	(89.90)	1,315.47	25,125.59	6,066.44			
5610003	External Settlement Contract Labor	(901.52)	13,296.17	114,072.13	3,425.57			
5610004	External Settlement Consulting	(447.59)	18,629.74	15,116.62	2,897.13			
5610005	External Settlement Contract Outside Ven		303.36	(120.31)	94.04			
5610006	External Settlement Materials	(0.46)	(2.53)	1,370.43	0.77			
5610007	External Settlement Employee Expense	(0.01)	66.70	58.89	1,141.37			
5610008	External Settlement Transportation		(3,852.02)					
5610009	External Settlement Miscellaneous	1,798.10	1,771.50	19,190.96	704.57			
5610011	External Settlement Overhead	37,044.97	191,440.32	5,296.24	(2,160.92)			
8000000	Prod Labor Bargaining Benefit Group 1	(30,410.83)	131,312.69	7,842.24	1,421.76			
8000005	Prod Labor Bargaining Benefit Group 6		(7,966.15)		7.98			
8000020	Prod Labor Non-Bargaining Benefit Grp 1	166,680.99	535,547.20	54,773.61	(61,054.94)			

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8000022	Prod Labor Non-Bargaining Benefit Grp 3	25.75						
8000023	Prod Labor Non-Bargaining Benefit Grp 4	2,071.44	4,798.93	13,175.62	(122.62)			
8000025	Prod Labor Non-Bargaining Benefit Grp 6	(258.84)						
8000037	Productive Labor Non-Barg No Load	(7,126.07)	(1,803.92)	(43.26)	60.58			
8000100	Premium		(9.10)					
8000105	Overtime	1,585.43	21,751.87	488.80	563.39			
8000110	Other Compensation		3,454.18					
8000115	Other Compensation Craft Welfare Fund		(4,331.86)		5.83			
8100000	Non-Prod Labor Bargaining Benefit Grp 1	185,797.37	256,895.24	256,040.07	111,249.95			
8100020	Non-Prod Labor Non-Bargaining Ben Grp 1	1,495,538.35	1,873,789.34	2,213,205.59	1,229,449.62			
8100022	Non-Prod Labor Non-Bargaining Ben Grp 3	1,345.59						
8100023	Non-Prod Labor Non-Bargaining Ben Grp 4	4,984.56	13,068.50	16,920.25	10,439.69			
8100205	AG Overhead	0.59						
8100260	Purchasing - Overhead	140,326.78		213,145.45	153,896.17			
8100315	Warehouse - Overhead	0.03						
8100500	NonProd Bargaining Labor G1_OH Alloc	3,696.27	4,867.22	943.32				
8100502	NonProd NonBarg Labor G1_OH Alloc	31,105.09	4,074.66	21,998.53				
8100530	Purchasing_OH Allocation	(45,631.62)		262,424.10	81,958.48			
8100532	Fleet_OH Allocation	(7,458.89)						
8100533	Warehouse Energy Supply_OH Allocation	199.72						
8100534	Purchasing Nuclear_OH Allocation	(0.08)						
8100540	NonProd NonBarg Labor G3_OH Alloc	(409.32)						
8100541	NonProd NonBarg Labor G4_OH Alloc	676.63	(372.78)	(41.25)				
8100550	Fleet-Base Rates		39,359.37	76,148.08	38,513.55			
	Total	77,978,351.02	73,605,079.47	85,690,032.49	91,378,469.54	111,306,031.47	124,611,488.08	128,731,284.83

Northern States Power Company
AGIS: AMI and FAN Expenditures

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
Communications Network																			
FAN Bus Sys Costs	1,709	51,120	88,387	59,329	56,142	15,200	0	0	0	0	0	0	0	0	0	0	0	**271,887**	**217,842**
FAN Bus Sys WiMAX Cost	334,633	10,011,076	17,309,267	11,618,600	10,994,506	2,976,466	0	0	0	0	0	0	0	0	0	0	0	**53,244,549**	**42,660,847**
FAN Bus Sys Contingency	73,854	1,267,037	2,253,221	1,166,606	1,103,942	298,863	0	0	0	0	0	0	0	0	0	0	0	**6,163,522**	**4,979,818**
TOTAL - Communications	***410,196***	***11,329,233***	***19,650,875***	***12,844,535***	***12,154,590***	***3,290,528***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***59,679,958***	***47,858,507***
IT Systems and Integration																			
IT Hardware	1,504,080	2,537,978	2,141,049	545,521	556,814	568,340	580,104	0	0	0	0	0	0	0	0	0	0	**8,433,885**	**7,028,256**
IT Software	1,064,115	1,552,117	5,536,877	4,669,670	323,141	0	0	0	0	0	0	0	0	0	0	0	0	**13,145,919**	**10,838,063**
IT Labor + Project Management	1,725,374	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,725,374**	**1,621,097**
IT Contingency	0	0	0	11,176,589	605,252	548,564	174,031	0	0	0	0	0	0	0	0	0	0	**12,504,436**	**9,642,915**
TOTAL - IT Systems and Integration	***4,293,568***	***4,090,095***	***7,677,926***	***16,391,780***	***1,485,207***	***1,116,904***	***754,136***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***35,809,615***	***29,130,330***
TOTAL CAPITAL	**4,703,764**	**15,419,328**	**27,328,801**	**29,236,315**	**13,639,797**	**4,407,432**	**754,136**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**95,489,573**	**76,988,837**
O&M ITEMS																			
Communications Network																			
FAN Network Business Systems	0	0	335,766	3,171,422	2,673,589	1,491,278	499,575	671,918	685,827	700,023	714,514	729,304	744,401	759,810	775,538	791,592	807,978	**15,552,536**	**9,460,970**
FAN WiMAX Cost	233,600	357,245	427,150	434,290	562,241	1,048,049	653,607	0	0	0	0	0	0	0	0	0	0	**3,716,182**	**2,782,723**
NOC Opco Allocation	200,000	408,280	625,097	638,037	651,244	664,725	678,485	692,529	706,864	721,497	736,432	751,676	767,235	783,117	799,328	815,874	832,762	**11,473,181**	**6,445,717**
FAN Network Bus Sys Contingency	0	0	301,130	686,305	623,871	517,616	243,271	124,153	0	0	0	0	0	0	0	0	0	**2,496,348**	**1,830,131**
TOTAL - Communications	***433,600***	***765,525***	***1,689,144***	***4,930,054***	***4,510,945***	***3,721,669***	***2,074,937***	***1,488,601***	***1,392,691***	***1,421,520***	***1,450,946***	***1,480,980***	***1,511,636***	***1,542,927***	***1,574,866***	***1,607,466***	***1,640,740***	***33,238,246***	***20,519,541***
IT Systems and Integration																			
IT Hardware	42,114	1,654,282	1,678,585	1,705,324	1,740,624	1,776,655	1,813,432	1,850,970	1,889,285	1,928,393	1,968,311	2,009,055	2,050,642	2,093,091	2,136,418	2,180,642	2,225,781	**30,743,604**	**17,268,781**
IT Software	27,285	85,988	983,487	1,845,314	2,011,390	2,053,026	2,095,523	2,138,900	2,183,176	2,228,367	2,274,495	2,321,577	2,369,633	2,418,685	2,468,752	2,519,855	2,572,016	**32,597,467**	**17,432,600**
IT Labor	0	2,056,405	1,553,273	1,750,246	1,680,090	1,717,226	1,721,011	1,789,073	1,859,799	1,933,290	2,009,656	2,089,007	2,171,461	2,257,136	2,346,156	2,438,653	2,534,759	**31,907,241**	**17,784,018**
Common Corporate Business System development-Allocation	646,904	4,270,861	5,304,505	11,866,886	12,378,199	10,847,247	10,347,121	0	0	0	0	0	0	0	0	0	0	**55,661,724**	**41,239,207**
IT Contingency	0	997,287	9,826,939	4,112,864	2,099,639	2,145,629	2,192,624	2,240,646	2,289,716	2,339,857	2,391,093	2,443,448	2,496,946	2,551,611	2,607,470	2,664,547	2,722,871	**46,123,186**	**28,075,602**
TOTAL - IT Systems and Integration	***716,303***	***9,064,823***	***19,346,789***	***21,280,633***	***19,909,942***	***18,539,783***	***18,169,711***	***8,019,589***	***8,221,975***	***8,429,907***	***8,643,555***	***8,863,087***	***9,088,683***	***9,320,523***	***9,558,795***	***9,803,697***	***10,055,427***	***197,033,221***	***121,800,207***
TOTAL O&M	**1,149,903**	**9,830,348**	**21,035,932**	**26,210,687**	**24,420,887**	**22,261,452**	**20,244,648**	**9,508,190**	**9,614,666**	**9,851,427**	**10,094,500**	**10,344,068**	**10,600,319**	**10,863,450**	**11,133,661**	**11,411,162**	**11,696,167**	**230,271,467**	**142,319,748**
GRAND TOTAL CAPITAL & O&M	**5,853,667**	**25,249,675**	**48,364,733**	**55,447,002**	**38,060,684**	**26,668,884**	**20,998,783**	**9,508,190**	**9,614,666**	**9,851,427**	**10,094,500**	**10,344,068**	**10,600,319**	**10,863,450**	**11,133,661**	**11,411,162**	**11,696,167**	**325,761,039**	**219,308,585**

Northern States Power Company
AGIS: FLISR and FAN Expenditures

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Category
CAPITAL ITEMS - SUMMARY																							
Communications Network																							
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	62,744	1,877,077	3,245,488	2,178,488	2,061,470	558,087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,983,353**	**7,998,909**	**Direct and Tangible**
FAN Bus Sys Contingency	48,467	831,493	1,478,676	765,585	724,462	196,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**4,044,811**	**3,268,006**	**Direct and Tangible**
TOTAL - Communications	**111,210**	**2,708,569**	**4,724,164**	**2,944,073**	**2,785,932**	**754,216**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**14,028,164**	**11,266,914**	
IT Systems and Integration																							
ADMS FLISR Integration	0	372,780	503,962	521,853	1,023,270	1,059,597	807,499	836,165	865,849	896,587	0	0	0	0	0	0	0	0	0	0	**6,887,562**	**4,636,414**	**Direct and Tangible**
IT Contingency	0	0	0	299,788	632,358	654,807	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,586,953**	**1,147,107**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***372,780***	***503,962***	***821,641***	***1,655,629***	***1,714,403***	***807,499***	***836,165***	***865,849***	***896,587***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,474,515***	***5,783,521***	
TOTAL CAPITAL	**111,210**	**6,214,857**	**13,637,130**	**10,048,307**	**13,491,578**	**10,910,457**	**7,146,728**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**84,093,414**	**59,596,959**	
O&M ITEMS - SUMMARY																							
Communications Network																							
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	
TOTAL O&M	**43,800**	**66,983**	**80,091**	**81,429**	**105,420**	**196,509**	**122,551**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**696,784**	**521,761**	
GRAND TOTAL CAPITAL & O&M	**155,010**	**6,281,841**	**13,717,220**	**10,129,736**	**13,596,999**	**11,106,966**	**7,269,279**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**84,790,198**	**60,118,719**	

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Exhibit___(DCH-1), Schedule 10
Page 1 of 1

Northern States Power Company
AGIS: IVVO and FAN Expenditures

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Categories
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**189**		
CAPITAL COSTS																							
Communications Network																							
Communications Operations-IVVO Budget	0	0	61,332	115,547	110,814	104,193	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**391,886**	**293,733**	**Direct and Tangible**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	20,915	625,692	1,081,829	726,163	687,157	186,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,327,784**	**2,666,303**	**Direct and Tangible**
FAN Bus Sys Contingency	16,156	277,164	492,892	255,195	241,487	65,376	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,348,270**	**1,089,335**	**Direct and Tangible**
TOTAL - Communications	37,070	902,856	1,636,054	1,096,905	1,039,458	355,598	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**5,067,941**	**4,049,371**	
IT Systems and Integration																						**0**	
Xcel Personnel [ADMS IVVO Integration]	0	0	803,466	1,375,982	2,021,270	2,024,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,225,118**	**4,611,361**	**Direct and Tangible**
External resources (Consultants, contractors etc.) [GEMS]	0	0	520,914	265,849	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**786,763**	**639,234**	**Direct and Tangible**
GEMS hardware	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**	**Direct and Tangible**
Varentec PM & Services	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**	**Direct and Tangible**
IT Project Management	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**	**Direct and Tangible**
IT Travel Expenses	0	0	10,418	5,317	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,735**	**12,785**	**Direct and Tangible**
Security	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**	**Direct and Tangible**
Contingeuncy	0	0	130,158	158,367	190,817	188,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**667,722**	**500,682**	**Direct and Tangible**
Program Management	0	0	104,183	319,018	325,622	332,362	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,081,185**	**802,089**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***0***	***1,881,688***	***2,284,042***	***2,537,708***	***2,545,144***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***9,248,582***	***6,949,692***	
TOTAL CAPITAL	**37,070**	**902,856**	**3,517,741**	**3,380,947**	**3,577,166**	**2,900,742**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**14,316,523**	**10,999,063**	
O&M ITEMS																							
Communications Network																							
On-going Communications Network costs	0	0	0	0	4,920	15,829	25,585	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	**567,832**	**250,941**	**Direct and Tangible**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	14,600	22,328	26,697	27,143	35,140	65,503	40,850	0	0	0	0	0	0	0	0	0	0	0	0	0	**232,261**	**173,920**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	***14,600***	***22,328***	***26,697***	***27,143***	***40,060***	***81,332***	***66,435***	***35,371***	***36,103***	***36,850***	***37,613***	***38,392***	***39,187***	***39,998***	***40,826***	***41,671***	***42,533***	***43,414***	***44,312***	***45,230***	***800,094***	***424,861***	
IT Systems and Integration																							
Program Management	0	0	22,576	35,446	36,180	36,929	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**131,132**	**98,245**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***0***	***22,576***	***35,446***	***36,180***	***36,929***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***131,132***	98,245	
TOTAL O&M	14,600	22,328	49,273	62,590	76,240	118,261	66,435	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	931,225	523,106	
GRAND TOTAL CAPITAL & O&M	51,670	925,184	3,567,014	3,443,536	3,653,406	3,019,003	66,435	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	15,247,748	11,522,169	

PUBLIC DOCUMENT – NOT PUBLIC DATA HAS BEEN EXCISED
Schedule 11 – Business Systems AMI RFP Results
Schedule 12 – Business Systems FAN RFP Results

Trade Secret Justification

Schedules 11 and 12 are 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. These summaries were prepared by Business Systems and Sourcing employees and their representatives in 2017 (Schedule 11) and 2015 (Schedule 12), 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. These Schedules contain 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.

Direct Testimony and Schedules
Christopher C. Cardenas

Before the Minnesota Public Utilities Commission
State of Minnesota

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

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

Customer Care and Bad Debt Expense

November 1, 2019

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Christopher C. Cardenas. I am Vice President of Customer Care for Xcel Energy Services Inc. (XES), which provides services to Northern States Power Company (NSPM or the Company).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have more than 20 years of experience in the areas of customer service and finance for energy utilities, cable and telecommunication companies. I joined XES in January 2019, previously serving as Vice President of Customer Services for PPL Electric Utilities in Pennsylvania. In my current position, I am responsible for the overall business performance of the Customer Care organization. Prior to this, I held various customer service and financial leadership roles with Time Warner Cable, Comcast Cable, U.S. Cellular and Sprint Nextel. I have also held various positions in corporate strategy, customer service operations and business development. My resume is provided as Exhibit___(CCC-1), Schedule 1.

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

A. My testimony provides an overview of the Customer Care organization and its 2020-2022 Operation and Maintenance (O&M) expense levels. I share ways we measure customer satisfaction for work Customer Care performs. I also present and discuss the Company's commodity and non-commodity bad debt expense, and the actions we have taken to minimize and manage it to the benefit of customers. Finally, I discuss impacts that Advanced Grid Infrastructure and Security (AGIS), and specifically Advanced Metering

Infrastructure (AMI), will have on Customer Care costs, functions, and processes, as well as changes that are needed to facilitate the transition to AMI for customers.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Customer Care organization has achieved strong customer satisfaction results, controlled its O&M expenses, and outperformed other utilities in managing bad debt expense. The 2020 test year O&M expense I propose for the Customer Care organization is $33.2 million for the State of Minnesota Electric Jurisdiction. This level of O&M expense continues Customer Care's trend of relatively flat levels of O&M expense since 2016, while continuing to achieve strong results in the Company's service quality measures and high levels of satisfaction with the service we provide our customers.

The 2020 test year bad debt ratio we propose is 0.35 percent, which results in a 2020 test year commodity bad debt expense of $11.3 million, and approximately $80,000 for non-commodity bad debt expense for the State of Minnesota Electric Jurisdiction. In addition to bad debt performance comparing favorably to other utilities, this bad debt ratio is consistent with performance since 2016.

The AGIS initiative is a comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. Implementation of advanced metering technology and the communications network will enable the availability of detailed and timely data, system automation, and communications enhancements that will impact and provide benefits for our customers and the Customer Care organization. As I will describe below, the process changes enabled by advanced grid implementation will help reduce Customer Care O&M expenses in meter reading, and potentially other areas.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present the remainder of my testimony in the following sections:

- *Customer Care Organization.* I discuss my organization in terms of the business functions it provides to the Company and its customers. I also discuss the improvements we have made to various aspects of our service and the research we have done to understand our customers and to measure their satisfaction with the service we provide. In addition, I summarize the Company's service quality results. In this section, I also present the overall Customer Care O&M budget and the budgets by business function.
- *Commodity Bad Debt Expense.* This is the bad debt expense associated with the provision of energy services. I discuss the test year expense and proposed bad debt ratios, as well as how we determine our bad debt ratios and manage our bad debt expense.
- *Non-Commodity Bad Debt Expense.* This is bad debt expense associated with all types of retail customer billing, other than the provision of energy services. I discuss the Company's test year levels of expense, the various components of non-commodity bad debt expense, and what the various business functions do to manage non-commodity bad debt expense.
- *The AGIS Initiative.* I discuss Customer Care's responsibilities with respect to implementation of the Company's proposed AGIS initiative, including meter reading and billing, as well as direct customer contacts

that will support and facilitate AGIS implementation. I also discuss the impacts and benefits of AGIS from the Customer Care perspective, the framework for customer opt-out provisions, and how advanced grid capabilities will enable new products and services for our customers. I also discuss potential impacts to Customer Care operational and customer service metrics, and how the Company plans to track and report progress metrics as AGIS is implemented.

II. CUSTOMER CARE ORGANIZATION

A. Overview

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR TESTIMONY.

A. In this section, I discuss the structure of the Customer Care organization and describe the various functions involved in providing service to the Xcel Energy organization, including NSPM and the other Operating Companies and their customers. I also present the Company's test year O&M expense, and discuss how we have managed to keep O&M expenses relatively flat since 2012 while introducing new customer programs and options and maintaining high levels of customer satisfaction relative to the work Customer Care performs.

Q. PLEASE DISCUSS THE FUNCTIONS OF THE CUSTOMER CARE ORGANIZATION AND HOW THEY RELATE TO THE COMPANY'S OVERALL BUSINESS GOALS.

A. The Customer Care organization performs essential functions that help the Company effectively provide its customers energy products and services and high levels of customer service. We ensure energy use is measured and billed accurately, collect and process customer payments, and assist our customers

Only the testimony necessary to support the Company's Advanced Grid Intelligence and Security (AGIS) Initiative have been included in the Integrated Distribution Plan (IDP) filing. Accordingly, we have excised non-AGIS pages from this attachment.

Table 11

Non-Commodity Bad Debt Expense by Business Area

State of Minnesota Electric Jurisdiction

($ millions)

	Actual Expense			July Forecast	Test Year	Plan Years	
	2016	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**
Customer Care	$0.09	$0.08	$0.08	$0.07	$0.08	$0.08	$0.08
Distribution Operations	$0.60	$0.68	$0.44	$0.19	$0.15	$0.15	$0.15
Total	*$0.69*	*$0.76*	*$0.51*	*$0.27*	*$0.23*	*$0.23*	*$0.23*

Q. HOW DID THE COMPANY DEVELOP THE 2020 THROUGH 2022 NON-COMMODITY BAD DEBT EXPENSE LEVELS?

A. Each of the functions identified above assesses its current reserve in light of expected test year activities, such as expected billing amounts and Company credit policies, and then budgets accordingly.

V. THE ADVANCED GRID INFRASTRUCTURE AND SECURITY INITIATIVE

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

A. In this section, I discuss Customer Care's responsibilities with respect to implementation of the Company's proposed Advanced Grid Infrastructure and Security (AGIS) initiative. Specifically, Customer Care is responsible for meter reading and billing, as well as direct customer contacts that will support and facilitate AGIS implementation. I discuss the impacts and benefits of

AGIS from the Customer Care perspective. I provide details on how the Customer Care team will manage customer questions and concerns as the AGIS initiative is being deployed, the framework of a customer opt-out option, and how advanced grid capabilities will enable new products and services for our customers. I also discuss impacts to Customer Care operational and customer service metrics, and how the Company plans to track and report progress metrics as AGIS is implemented.

Q. HOW IS THE COMPANY PRESENTING ITS OVERALL SUPPORT FOR THE AGIS INITIATIVE?

A. In addition to my testimony, a discussion of the overall AGIS initiative and customer experience is provided in the Direct Testimony of Mr. Gersack. The budget for AGIS implementation is primarily split between the Distribution Operations and Business Systems areas of the Company, as those areas are responsible for implementing the technologies and systems for the AGIS initiative. Company witnesses Ms. Kelly A. Bloch and Mr. David C. Harkness provide testimony for those business areas, respectively. Mr. Gersack provides support for program management costs and the overall AGIS customer experience. A summary of AGIS cost and benefits analyses are addressed in the Direct Testimony of Company witness Dr. Ravikrishna Duggirala.

Q. HOW IS THIS SECTION OF YOUR TESTIMONY ORGANIZED?

A. I first describe the AGIS initiative and Customer Care's role with respect to implementation. This includes an overview of the impacts, benefits and opportunities associated with AGIS from the Customer Care perspective.

I then discuss our current meter reading technology, what will change with installation of advanced meters, and how that affects meter reading operations.

Next, I discuss how Customer Care will provide support for AGIS during the advanced meter installation phase. While Mr. Gersack describes our overall customer education plan, I discuss how Customer Care will work in conjunction with Customer Communications to ensure customers are informed about the new meters and capabilities, and that we answer all questions as they arise. This includes plans for the Company's contact center as well as the meter installation vendor as it relates to direct contact with our customers. I also discuss the opt-out framework we have developed for customers who choose to decline advanced meter installation.

I then discuss impacts to billing operations and the minimal changes necessary to enable AMI billing. I also discuss how AGIS implementation will enable new capabilities, products and services, and the benefits related to Customer Care and certain other business areas that intersect. I detail which capabilities will be available to customers upon installation of the advanced meters, and which will be enabled through new products or services that will require separate Commission approval. For example, these future filings may address a pre-pay option for customers, use of remote reconnection and disconnection capabilities, or full residential time of use rates. We recognize that these new products and services will require additional filings with the Commission and may involve a stakeholder engagement processes to inform development, but they are important to understand in assessing the potential benefits of AGIS.

I also provide details related to the quantifiable benefits of AGIS implementation that are related to Customer Care. I describe these benefits here to support their inclusion in the Cost Benefit Analysis (CBA) as discussed by Dr. Duggirala.

Finally, I discuss tracking and reporting of Customer Care's operational and quality of service metrics. For those metrics that we expect will be impacted by AGIS implementation, I discuss how the Company plans to track and report these metrics as AGIS is implemented. I also discuss future filings with the Commission and separate proceedings that may be necessary to ensure stakeholder review and input relative to the Company's service quality reporting.

A. AGIS Overview

Q. WHAT IS AGIS?

A. The AGIS initiative is a comprehensive plan that will advance the Company's electric distribution system, provide customers with more choices, and enhance the way the Company serves its customers. AGIS provides the foundation for an interactive, intelligent, and efficient grid system that will be even more reliable and better prepared to meet the energy demands of the future.

Q. TO PROVIDE A FRAMEWORK FOR THE REMAINDER OF YOUR TESTIMONY, PLEASE IDENTIFY THE CORE COMPONENTS OF AGIS THAT WILL IMPACT THE CUSTOMER CARE ORGANIZATION.

A. As outlined in Mr. Gersack's testimony, and discussed in detail in the testimonies of Ms. Bloch and Mr. Harkness, the core components of AGIS that will impact Customer Care are the Advanced Metering Infrastructure (AMI) and the Field Area Network (FAN).

- *AMI* is an integrated system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between the Company's business and operational data systems and customer meters. AMI enables timely monitoring and communication between the meter and Advanced Distribution Management System (ADMS) about, among other things, energy usage and outages, and is a necessary first step to better customer data, enhanced customer service, and the addition of applications and options for future energy management and optionality.

- *The FAN* is the communications network that will enable communications between the existing communications infrastructure for the distribution system and the new advanced grid components.

These two components work in conjunction with the foundational ADMS that the Company is currently implementing.

Q. WHAT IS THE OVERALL IMPLEMENTATION SCHEDULE FOR AGIS?

A. As outlined by Mr. Gersack, the Company already has begun limited deployment of AMI and the FAN to support the Company's residential Time of Use (TOU) pilot scheduled to launch in April 2020. To ensure communications are in place for AMI functionality, the FAN deployment precedes AMI by approximately three to six months. Beyond the TOU pilot phase, our present AMI plan for Minnesota is to begin full AMI deployment in 2021 and to conclude in 2024, in anticipation of the end of the support for AMR meters and the end of our present service agreement. Ms. Bloch and Mr. Harkness describe the implementation plan in more detail.

Q. HOW WILL THESE COMPONENTS IMPACT THE CUSTOMER CARE ORGANIZATION?

A. The availability of detailed and timely data, system automation, and communications enhancements, will impact and provide benefits for our customers and the Customer Care organization. As discussed in detail in Mr. Harkness' testimony, work of the Business Systems organization will include integration of AMI with "back office applications," meaning the software applications that support the Company's customer service needs, billing, payment remittance, service order management, outage management, meter reading, and asset inventory lifecycle management applications to utilize the customer data, outage data, and other information supplied by the advanced distribution grid. This will enable changes to current business practices, and positively transform the nature of interactions with our customers.

Further, as I will describe below, the process changes enabled by advanced grid implementation will help reduce Customer Care O&M expenses in meter reading, and potentially other areas.

Q. ARE THERE SPECIFIC COSTS FOR AGIS IMPLEMENTATION IN THE CUSTOMER CARE BUDGET IN THIS CASE?

A. No. The overall budget to implement AGIS is split between the Distribution Operations and Business Systems budgets, which are presented and supported in the testimonies of Ms. Bloch and Mr. Harkness. However, O&M cost reductions attributed to reduced meter reading costs as a result of AGIS implementation are reflected in Customer Care's MYRP O&M budget in this case. I discuss this O&M cost reduction further in the next section.

Q. ARE THERE OTHER QUANTIFIABLE BENEFITS OF AGIS IMPLEMENTATION RELATED TO THE CUSTOMER CARE ORGANIZATION?

A. Yes. As it relates to the Customer Care organization, AMI technology enables cost reductions primarily due to remote connection and disconnection capabilities and improved data and analytics. Specifically, the Company anticipates benefits related to reductions in energy theft, consumption at inactive premises, and uncollectible/bad debt. I address these quantifiable benefits in Section F below, and Dr. Duggirala discusses how these benefits are reflected in the CBA.

Q. ARE THESE COST REDUCTIONS INCLUDED IN CUSTOMER CARE'S MYRP BUDGETS IN THIS CASE?

A. No. Unlike the meter reading O&M expense reduction, these benefits are not anticipated during the term of the multi-year rate plan. In addition, realization of these benefits may require future filings and Commission approvals.

B. Meters and Meter Reading

1. *Current Meter Technology and Service Agreement*

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT METER TECHNOLOGY AND METER READING SERVICE AGREEMENT.

A. As discussed above, the Company currently uses AMR technology. Meter readings are collected and provided to the Company via a proprietary network by Cellnet. In addition to providing the meter readings, Cellnet owns and maintains the communication network and software used to transmit the readings. Cellnet also owns and maintains meter communication modules which refers to the radio interface that is installed as part of the electric meter. The Company's payments to Cellnet for these services are reflected as O&M expense in our budgets.

The Cellnet AMR system in service in Minnesota is nearing end of life. Cellnet has informed the Company that it will stop manufacturing the AMR meter reading modules and components compatible with the current system in 2022, so there will be no support for ongoing maintenance after that time. Further, our current contract with Cellnet for meter reading services ends at the end of 2025, with an option to extend it through 2026 at increased cost.

Given these circumstances, the Company must plan an electric metering solution for the years 2022 and beyond. Ms. Bloch and Mr. Harkness discuss the Company's approach to this process, our consideration of alternatives, and the additional customer and system benefits enabled by advanced metering technology. Below I describe how the AMI and FAN solutions affect customers through our Customer Care organization.

2. AMI and Meter Reading Cost Reductions

Q. PLEASE DESCRIBE, AT A HIGH LEVEL, THE AMI TECHNOLOGY THE COMPANY IS PROPOSING TO IMPLEMENT.

A. AMI is a system of advanced meters, communication networks, and data processing and management systems that enables secure two-way communication between Xcel Energy's business and operational data systems and customer meters. AMI enables timely monitoring and communication about, among other things, energy usage and outages, and is a necessary first step to better customer data, enhanced customer service, and the addition of applications and options for future energy management and optionality.

Q. PLEASE DISCUSS THE CURRENT CELLNET CONTRACT IN LIGHT OF THE PLANNED TRANSITION TO AMI.

A. The current Cellnet contract requires the Company to pay for meter reading services for a minimum of two million (total electric and gas) meters through December 31, 2021. The Company currently has 2.4 million Cellnet meters in service. Beginning in 2022, the Company can reduce meter reading costs when it transitions below two million Cellnet meters as a result of our anticipated AMI deployment schedule. Customer Care's meter reading O&M expenses would decline over time as AMI electric meters are deployed in Minnesota. These reductions are incorporated into our O&M budget in this case.

Q. HOW WILL METER READING CHANGE AFTER AMI DEPLOYMENT?

A. AMI technology will provide for automated meter reading via the Company-owned FAN communications network. There may be instances when a meter is not read by the AMI system, primarily due to network communication issues or meter issues. In these cases, the meter will be manually read, which is the same as we do today when the Cellnet system is unable to communicate with a specific meter. In addition, there may be customers who opt-out of AMI meter installation, which will require that the Company manually read meters for these customers. In the following section, I discuss the Company's plans for allowing customers to opt out of an AMI meter if they choose.

Q. WHAT ARE THE FORECASTED METER READING O&M COST REDUCTIONS ASSOCIATED WITH AMI DEPLOYMENT?

A. The forecasted O&M cost reductions associated with AMI deployment that are reflected in Customer Care's 2020 through 2022 budgets are represented in a separate line item "reduction" based on our forecasted deployment timeline. O&M budget reductions would generally grow over time as meters are deployed, reaching almost $8.9 million in annual savings by 2024. These cost savings are shown in Table 12 below.

Table 12
Anticipated Customer Care O&M Savings in Meter Reading Costs
From AMI Electric Meter Deployment
State of Minnesota Electric

Year	Customer Care O&M Savings	Annual AMI Meter Deployment	Cumulative AMI Meter Deployment
2019	$4,000	8,916	8,916
2020	$95,000	8,584	17,500
2021	$786,000	121,800	139,300
2022	$3,097,000	630,000	769,300
2023	$8,231,000	590,000	1,359,300
2024	$8,875,000	40,000	1,399,300

These reductions are reflected in Customer Care's O&M budget forecasts for 2020-2022 in this case. In Section F, I discuss how the Cost-Benefit analysis presented by Dr. Duggirala incorporates this reduction over the term addressed by the CBA.

C. AMI Installation

1. Customer Care Support for AMI Installation

Q. WHAT ARE CUSTOMER CARE'S PLANS TO SUPPORT AMI INSTALLATION BEGINNING IN 2021?

A. Customer Care is working closely with Customer Communications to support all phases of the Customer Communications and Education Plan (Communications Plan) discussed in Mr. Gersack's direct testimony. This Communications Plan is designed to inform customers before, during, and after AMI deployment regarding what they can expect and how they can use and benefit from AMI.

Q. HOW WILL YOU PREPARE CUSTOMER CARE EMPLOYEES TO PROVIDE SUPPORT TO CUSTOMERS REGARDING THE AMI DEPLOYMENT?

A. Training for Customer Care employees is an important step to enhance customer understanding and satisfaction, as well as reduce customer complaints. In anticipation of AMI deployment in Colorado, we have already developed and started to deliver training to Customer Care employees regarding AMI technology, the benefits for customers, and how it will impact their work. This training will help prepare our employees for Minnesota AMI meter deployment, as well as for deployments in other states, such as Colorado.

Training has been and will continue to be developed and delivered based on an employee's role in the organization, what they need to know to do their job, and when they need to know it. The Company has utilized training experts from inside and outside the organization to create the training developed so far. Training development and delivery is an existing function and competency within the Company today. Customer Care employees receive training throughout the year to perform their jobs well and learn about changes impacting their work to best serve customers. AMI-related training development and delivery will continue as new knowledge needs to be shared over time.

All Customer Care employees will take general AMI program overview training to become familiar with the technology, benefits and general program plan. After that, training will be tailored to an employee's role. For example, a contact center agent would take training regarding the Minnesota TOU pilot, how a customer can opt out of the TOU pilot, and how to handle an AMI-related customer inquiry. Some of the training is universal and applies to AMI implementation in any state. Other training will be targeted to a particular state's deployment and offerings. The training is delivered and assigned through an online Learning Management System (LMS) for efficient delivery and tracking to insure completion within appropriate timeframes.

Q. WHAT EFFORTS WILL THE COMPANY UNDERTAKE TO HELP MITIGATE ANY INCONVENIENCE TO CUSTOMERS DURING AMI DEPLOYMENT?

A. The Communications Plan noted earlier uses an integrated, expansive, and multi-channel approach to reach as many customers a possible. The plan is designed to build awareness of advanced grid capabilities, proactively educate customers about the AMI installation process, and keep customers informed at every stage leading up to installation and during installation. Customer Care is working closely with Customer Communications to provide the necessary information and answer questions when customers contact our call centers. In addition, as I discuss in the next section, we are developing plans with respect to our meter installation vendor as they will also have direct contact with our customers.

Q. WHAT ARE CUSTOMER CARE'S PLANS TO TRACK CUSTOMER FEEDBACK RELATED TO AMI INSTALLATION?

A. I discuss our plans for tracking customer feedback in our service quality reporting in Section G below, along with our plans for tracking call center activity related to AMI installation.

2. *Meter Installation Vendor Support*

Q. HOW DOES CUSTOMER CARE PLAN TO WORK WITH THE METER INSTALLATION VENDOR DURING AMI DEPLOYMENT?

A. The Company is committed to working with our meter installation vendor during AMI implementation to ensure our customers receive excellent service. We recognize that due to the volume of meter installations and the number of customers affected during the AMI deployment phases, the impact goes well beyond that of any other projects we would engage in during the normal course of providing service to our customers. As such, the Company and the meter installation vendor will work together to provide coordinated support and address all customer inquiries and any issues that may arise.

Q. PLEASE DISCUSS AT A HIGH LEVEL THE METER INSTALLATION VENDOR SELECTED BY THE COMPANY.

A. The Company selected Itron as the AMI meter vendor to provide the meters, installation, and project management. Ms. Bloch discusses the Itron selection for AMI meters in her testimony. Itron has extensive experience providing direct customer support during AMI meter deployments. They have worked on projects for several utilities, including Consumers Energy (1.8 million electric and 600,000 gas meter AMI deployment) and British Columbia Hydro (1.8 million electric meter AMI deployment currently in progress). They will also begin work for Nova Scotia Power (500,000 electric meter AMI deployment) in October 2019.

Q. PLEASE DISCUSS HOW THE COMPANY AND METER VENDOR WILL COORDINATE CUSTOMER SERVICE EFFORTS.

A. Itron is committed to working with the Company to address and resolve all customer inquiries related to the new meters throughout deployment. This will involve any communications received via telephone, email, letter, social media, PUC complaint, or other communication channel.

The meter installation vendor will be a key point of contact for the Company's customers during the meter installation process and will have a dedicated call center phone number for Xcel Energy's customers. The various communications and materials we plan to provide to customers prior to and during the installation will include specific directions to ensure our customers have the right contact information so any questions or issues will be resolved as quickly as possible. Our plan is to direct customers to call the vendor with any questions related to installation. However, if the vendor receives calls that should instead be directed to the Company, the vendor will also have the ability to warm transfer calls to the Company. (Warm transfer means the vendor representative would remain on the line to ensure the call is answered and the customer is successfully connected with a live Company agent.) Similarly, the Company will have the ability to warm transfer calls to the meter installation vendor as needed.

3. Opt-Out Provisions

Q. PLEASE DESCRIBE THE OPT-OUT PROVISIONS FOR CUSTOMERS ELECTING TO DECLINE INSTALLATION OF ADVANCED METER TECHNOLOGY.

A. The Company can provide the greatest benefits for all our customers by deploying advanced meters throughout our entire service territory. We also recognize the importance of providing our customers with the opportunity to decline the installation of an advanced meter, or have an advanced meter removed at any time, and discuss how we intend to provide clear information regarding this option.

We intend to provide the option for eligible customers to decline installation of an AMI meter. However, we believe these customers should also pay the cost of doing so in light of standard cost-causation principles. For a customer choosing a non-transmitting meter, the Company would need to manually probe the meter to obtain data for billing and energy use analysis, instead of having an AMI meter transmit meter readings electronically. The full set of data, including interval readings, would still be available to customers and could be used to bill advanced rates, such as time of use. This data would be available on a monthly basis after the readings were manually obtained, but it would not be transmitted at the time the interval readings occurred. This results in incrementally higher metering costs for the customer who opts out of an advanced meter.

Q. HOW DOES OPTING OUT OF AN AMI METER RESULT IN INCREMENTAL COSTS?

A. Primarily, the incremental costs associated with opting out of an AMI meter are due to the need for manual meter readings. This includes the cost to obtain manual meter readings in the field to bill consumption. There would also be incremental cost for field visits to remove a meter that does not communicate meter readings electronically and install an AMI meter for the next customer at that premise, or install a meter that does not communicate meter readings electronically after the initial meter deployment has occurred. We do not believe an additional charge associated with initial meter installation would be required if a customer made this choice prior to or at the time of initial meter deployment.

Q. PLEASE OUTLINE THE PROCESS FOR REQUESTING COMMISSION APPROVAL OF OPT-OUT PROVISIONS.

A. We plan to submit a separate filing with the Commission with our detailed opt-out proposal in 2020. Initial deployment of advanced meters is anticipated to begin in 2021. The timing of our filing will allow enough time for the proceeding to include stakeholder input and final Commission approval so that we can incorporate the necessary information when we begin pre-deployment communications with our customers. Our proposal will include the necessary tariff sheets reflecting the incremental costs and service provisions for customers who decline installation of AMI meters or choose to have the AMI meter removed at any time, as well as any associated rule variances.

D. Billing

Q. HOW WILL AMI IMPLEMENTATION AFFECT CUSTOMER BILLS?

A. AMI billing itself will result in one minor change to the customer bill, which will require a variance from Minn. R 7820.3500 on billing content. Minn. R 7820.3500 (A) requires that a customer's bill include "the present and last preceding meter readings." Customer bills currently include this information, with usage for the billing period determined as the difference between these two meter readings. In contrast, interval billing using AMI technology does not use this method of subtraction to calculate usage; instead, it individually measures consumption at predictable intervals (for example, every 15 minutes) and calculates the total amount to be billed for a given period without reference to the prior billing period. As such, with no other billing format changes, AMI bills will show 0 for the "previous reading," and the "current reading" will show the total energy usage for the billing period.

I note that the Company already bills many larger commercial customers using interval meter readings today, so our billing employees are familiar with this type of billing.

Although the necessary bill format change is limited as described above, with AMI, customers will be provided additional granular information and energy usage data on the MyAccount web portal. For customers opting into potential new services enabled by AMI technology, information may also be provided via other digital channels, which is discussed further in Mr. Gersack's testimony

Q. IS THE COMPANY REQUESTING THIS RULE VARIANCE AS PART OF THIS RATE CASE FILING?

A. No. We plan to submit a separate filing with the Commission requesting approval of the necessary rule variance in 2020. Initial deployment of advanced meters is anticipated to begin in late 2021. The timing of our filing will allow enough time for Commission review and approval prior to commencement of AMI installation.

Q. IS THE COMPANY ALSO CONSIDERING BILL FORMAT CHANGES?

A. Yes. As part of the coordinated customer experience efforts planned in 2020, a team will be re-evaluating the bill format in light of AMI deployment and considering other best practices. As a result, the Company may wish to propose additional bill format changes prior to AMI installation. We may submit a filing encompassing all proposed changes, not only the limited format change that may be required to implement AMI billing itself.

Q. HOW WILL AMI IMPLEMENTATION AFFECT CUSTOMER CARE'S BILLING OPERATIONS?

A. Billing Operations will perform the same work it does today, which is to address exceptions identified by the customer meter data and billing systems because they fall outside of established parameters and require intervention. The volume of meter data and billing exceptions that need to be handled by Billing Operations is expected to increase given the large number of meter exchanges that will occur during meter deployment.

Q. PLEASE DESCRIBE THE ADDITIONAL WORK ANTICIPATED WITH THE METER EXCHANGES.

A. Although the change to the actual customer bill is limited as described above, a typical meter exchange bill can be complex due to the meter being exchanged in the middle of a billing cycle and the manual entry of information. A sample bill showing a typical meter exchange bill is provided as Exhibit___(CCC)-1), Schedule 9.

Q. WHY DO METER EXCHANGE EXCEPTIONS GENERALLY OCCUR?

A. Meter exchange exceptions occur for several reasons, including a final reading that is incorrectly entered from a removed meter, an error in the date noted for the meter exchange, or a meter exchange that occurs during the normal billing window for a premise. An exception requiring intervention is typically flagged using pre-determined system parameters. Once flagged, it is routed to a work queue for review by Billing Operations. This typically happens before a bill is issued to a customer. Rarely, a bill may be issued containing an error. When the Company is notified by a customer of an error, a bill may need to be cancelled and re-issued.

Q. WILL AMI HAVE ANY IMPACT ON CUSTOMER CARE'S METER READING OR BILLING METRICS THAT ARE REPORTED UNDER THE SERVICE QUALITY RULES?

A. As with any comprehensive deployment of meter equipment and systems, the Company expects there may be an impact to meter reading or billing statistics initially during the installation phase, but not over the longer term. As I discuss further in Section G below, we will track and report these statistics using the established service quality reporting process. Any impacts specifically related to AGIS will be addressed in our separate service quality proceedings.

E. Customer Care Benefits

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF AMI IMPLEMENTATION FROM A CUSTOMER CARE PERSPECTIVE AND THE IMPACTS AND BENEFITS TO THE CUSTOMER CARE ORGANIZATION.

A. Initial deployment of advanced meters is anticipated to begin in late 2021. This initial deployment will be heavily focused on "getting the basics right."

For Customer Care, the basics include things like accurate, on-time customer billing, and ensuring we provide meaningful information and resolve any issues for customers about the installation process for new AMI meters.

Building on the basics, Mr. Gersack discusses in more detail how we intend to deploy new products and services, or improve existing services for our customers. We will take a judicious approach to deploying new products and services, focusing on areas where the cost-benefit is the highest, or where the satisfaction value is highest for our customers. Some of these new services impacting Customer Care may include a pre-pay billing option and remote connection and disconnection.

To enable the customer benefits or cost-savings these services would provide, we will need to make separate filings for Commission approval. In the following section I provide information on the quantifiable benefits that these services or AMI implementation, in general, are expected to provide.

Q. HOW WILL THE COMPANY PURSUE THE ADDITIONAL REGULATORY AND TARIFF CHANGES THAT WILL BE NEEDED TO ENABLE THE TRANSITION TO AMI METER TECHNOLOGY?

A. The Company plans to make a separate filing in 2020 to request approval of the rule variance that will be needed to transition to AMI meters.

In addition, to leverage the operational functionality the technology enables, we would also make separate filings for approval of any new products or services that may follow in the future. We recognize there are stakeholders who will have interest in these matters and how any changes affect customers.

We believe it is important to engage in a process to solicit stakeholder perspectives, discuss options, consider implications, and seek consensus; and intend to do so as we contemplate future services.

Q. WHAT ARE THE BENEFITS ASSOCIATED WITH REMOTE CONNECTION AND DISCONNECTION CAPABILITIES ENABLED BY AMI TECHNOLOGY?

A. The ability to remotely connect or disconnect service, when paired with customer protections, provides both cost and convenience benefits. When a customer wants to start service at a single-phase premise today, a field visit is necessary. This involves a fee for the customer and requires someone to be present at the location to meet a Company representative. With remote connection capability, a customer would not need to be present and a lower fee could be possible.

Another scenario where remote capabilities could be beneficial for a customer involves seasonal disconnections, where a customer may want electric service disconnected for a lengthy period of time because a home is unused. Instead of incurring the cost for two field visits to disconnect and reconnect service, a customer could schedule a remote disconnection and reconnection aligned with their occupancy needs. This would save customers money through reduced fees and energy usage and would be more convenient for them.

There would also be benefits when changes in tenants occur. AMI remote disconnection will enable the Company to disconnect electric service between tenants if there was no landlord agreement in place. Today, it is typically cost prohibitive to disconnect the account given the expense to send employees into the field. This is considered part of the line loss factor and can result in electricity being consumed with no responsible party to bill. While this benefit does not reside in Customer Care's O&M budget, Customer Care could positively reduce this loss by changing current business practices through AMI remote disconnection functionality. Remote disconnection and reconnection can also help reduce the cost of an unoccupied retail location for a building owner who has a vacant property that is between tenants as well.

Q. WHAT REGULATORY APPROVALS WOULD BE NEEDED TO IMPLEMENT REMOTE DISCONNECTION AND RECONNECTION OF SERVICE?

A. Use of remote connection/disconnection capabilities of AMI would require a variance from Minn. R 7820.2500, which requires a field visit prior to disconnection of service. This would be to enable the benefits described above related to start, stop, and transfer of service, shut-off between tenants, and seasonal disconnect/reconnect.

Q. DOES THE COMPANY PLAN TO MAKE A FILING TO ENABLE THE BENEFITS OF REMOTE CONNECTION/DISCONNECTION CAPABILITIES?

A. Yes. The Company anticipates submitting this filing in the future, and will include in such a filing a discussion of customer protections and benefits at that time. As I discuss further below, the AMI CBA assumes a level of cost reduction for remote connect/disconnect capabilities beginning in 2023. The Company would make a filing requesting Commission approvals necessary to enable these capabilities, allowing for stakeholder input into proposed changes and service provisions.

Q. ARE THERE OVERALL ADDITIONAL BENEFITS ASSOCIATED WITH REMOTE CONNECTION AND DISCONNECTION CAPABILITIES USED IN CONNECTION WITH NON-PAYMENT?

A. Yes. I note that for customers experiencing payment issues, the Company works to engage with them through proactive contacts, encourages them to seek energy assistance, and tries to establish a payment plan that works with their budget and personal situation. However, in cases where disconnection for non-payment is appropriate, the Company incurs significant costs to disconnect service. These costs are ultimately borne by a combination of the affected customers and the customer base as a whole. In addition, remote reconnection of service would reduce the cost of reconnecting service and enable faster service restoration for disconnected customers. Customer and employee safety would be enhanced as well.

While the Company believes it will be important to consider the use of remote disconnection and reconnection for customer non-payment, we recognize that any proposed changes would need to be addressed in a separate proceeding before the Commission. Implementing remote disconnection through AMI for non-paying accounts would require approval of a variance to Minn. R 7820.2500, as described above, as well as changes to our collection practices. The Company would engage with stakeholders during the development of any processes and procedures the Company would ultimately propose for Commission approval that would leverage these capabilities of the advanced grid.

Q. ARE THERE OTHER CAPABILITIES ENABLED BY AMI THAT PROVIDE ADDITIONAL CUSTOMER CARE BENEFITS?

A. Yes. Improved data and analytics enabled by AMI technology will also help reduce energy theft through better detection and prevention capability, which can provide an overall cost benefit for all of our customers. Today, customers who have been disconnected and try to reconnect their service illegally typically do so by removing the meter, removing the "boots" placed on the meter contacts, and then replacing the meter. This is an extremely unsafe and illegal practice. When AMI technology is in place, remotely disconnecting service will involve opening a disconnection switch on the meter to disconnect power to the customer. However, the meter still has power and can communicate over the network. If a customer removes the meter from the socket to bypass it, the Company would receive a notification flag over the network to indicate meter tampering. This will improve detection of instances where customers illegally bypass our meter to receive electricity without paying for it. These situations require time-intensive identification to detect today, but they can be detected automatically through AMI technology. For safety reasons, however, these situations will still require a physical visit to remedy.

Q. HOW DO ADVANCED GRID CAPABILITIES ENABLE THE PRE-PAYMENT OPTION YOU MENTIONED EARLIER IN YOUR TESTIMONY?

A. The advanced grid enables the Company to offer a pre-payment option due to the frequent energy usage measurements provided by AMI metering, and the ability to remotely disconnect and reconnect service.

Q. WHAT ARE THE BENEFITS OF OFFERING CUSTOMERS A PRE-PAY OPTION?

A. The main direct benefits for customers are fewer missed payments and no late payment fees, helping customers save money on their energy bills, and giving them greater control. Utility companies benefit from fewer missed payments, reduced costs for disconnections due to non-payment, and generally reduced costs and financial risk, which ultimately also benefit our customers. Several other utilities offer this option to customers, including Salt River Project, Alabama Power, APS, and Consumers Energy.

Q. DOES THE COMPANY ANTICIPATE OFFERING THIS PAYMENT OPTION TO CUSTOMERS?

A. Yes. The Company would like to offer a pre-payment option in the future enabled by our proposed investments in advanced grid technology and plans to include a detailed proposal in a future regulatory filing.

F. Quantifiable Benefits

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section, I discuss the quantifiable benefits of AGIS implementation that are related to Customer Care. I describe these benefits here to support their inclusion in the CBA as discussed by Dr. Duggirala. These benefits include:

- Reduction in meter reading costs;
- Reduction in the amount of energy theft;
- Reduced consumption at inactive premises; and
- Reduced uncollectible/bad debt.

Although the reduction in energy theft and reduced consumption at inactive premises would not impact Customer Care's O&M budget, these benefits are related to Customer Care operations and processes so are discussed in my testimony. The bad debt O&M expense reduction would impact Customer Care's O&M budget, but is not included in our budget in this case because these benefits are assumed to begin after the multi-year rate plan period. Additionally, to enable the necessary capabilities to realize the reduction in the amount of energy theft and bad debt expense, the Company would need to submit separate filings with the Commission.

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN METER READING EXPENSES?

A. First, I note that the reduction in meter reading O&M expense is reflected in the Customer Care O&M rate case budget forecast. This is due to AMI implementation that will begin during the multi-year rate plan.

Q. ARE THESE O&M REDUCTIONS REFLECTED IN THE AMI CBA?

A. Yes, but not as a separate line item. The CBA presented by Dr. Duggirala essentially looks at AMI costs and benefits compared to a reference case scenario, which is an AMR drive-by basic alternative. In other words, by implementing AMI, the Company will avoid costs associated with the alternative of replacing the current AMR Cellnet meter reading services with another service or potential drive-by meter reading option. This is a fixed benefit value calculated at the time the CBA analysis was done. The amount represents an avoided cost of a potential AMR basic alternative, besides AMI investment, since the current Cellnet system requires replacement in any case, as I discussed earlier. In this way, the meter reading O&M cost reduction is reflected in the CBA, not as cost reduction or "benefit" of AMI itself, but rather, as it is incorporated into the cost of the AMR alternative.

The avoided O&M meter reading expense was calculated by comparing the projected costs to replace the Cellnet system with a drive-by AMR solution. These reductions are included in the AMI cost benefit analysis as shown in Exhibit___(CCC-1), Schedule 10.

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN ENERGY THEFT?

A. As described above, the improved data and analytics enabled by AMI technology will help reduce meter tampering and energy theft through better detection and prevention capability, which can provide an overall benefit for all of our customers. To differentiate these instances more quickly from dead and malfunctioning meters, the Company will use an analytics software that enables frequent recording of energy consumption and detect anomalous patterns of energy resulting from theft and tampering. The Company will proceed to change the meter or make field adjustments and bring the situation to a normal condition, and will then bill and charge to customers the appropriate unbilled estimates.

To quantify these benefits, the Company estimated the reduction in the amount unbilled energy. We based this estimate on average sales for the five-year period 2014-2018. Industry organizations, such as EEI, estimate between 1 percent and 2 percent of revenue is lost to tampering and theft. Because there is no way to actually track this amount, the Company used 1 percent to provide a conservative estimate of lost revenue due to tampering and theft. Using the estimated amount of lost revenue, the Company's benefit calculation provides a conservative estimate of 0.1 percent (residential) and 0.15 percent (small C&I) reduction in unbilled energy. In other words, the Company anticipates the estimated lost revenue amount will decrease by these percentages. As a comparison, the Company also looked at Ameren Illinois' business case for AMI implementation. Our estimate is consistent with Ameren's energy theft reduction estimate.

As noted above, this benefit does not result in a reduction to the Customer Care budget, but rather an overall reduction to costs for energy that would not be offset by revenue. These reductions are included in the AMI cost benefit analysis as shown in Schedule 10.

Q. HOW DID THE COMPANY QUANTIFY THE REDUCTION IN CONSUMPTION ON INACTIVE METERS?

A. This benefit is related to electric consumption during a gap between two separate user accounts and the process to disconnect and connect service between tenants or owners. With the remote connect/disconnect capability; the Company will reduce usage on inactive meters.

To quantify these benefits, the Company calculated the average cost of consumption on inactive meters between the years 2014 through 2018, and estimates a 20 percent benefit. We believe this is a conservative benefit estimate.

As a comparison, the Company also looked at Ameren's business case for AMI implementation, which included a 56 percent reduction in consumption on inactive meters. Xcel Energy took a conservative approach for this benefit estimate due to Minnesota's Cold Weather Rule and the assumption that the Company will continue with its current practice, choosing not to disconnect residential heat-affected premises in the winter. With Minnesota's cold weather disconnection rules in effect between October 15 and April 15 (six months of the year), we believe a conservative benefit estimate would be half of Ameren's estimated benefit. This assumption is based, in part, on the difference between Illinois and Minnesota winter disconnection rules. The Illinois winter disconnection rule applies only if a customer is an electric heat customer and electricity is the customer's primary heat source. Additionally, the period it is in effect is shorter in duration than Minnesota's and does not apply to premises that do not have a responsible party. Even though not entirely comparable, our comparison with Ameren's estimate is informative. Further, our benefit estimate also assumes the Company would not use remote disconnection when there is a gap between tenants of less than three days. For these reasons, we believe our 20 percent benefit estimate is conservative.

As noted above, this benefit does not result in a reduction to the Customer Care budget, but rather an overall reduction to costs for energy that would not be offset by revenue. These reductions are included in the AMI cost benefit analysis as shown in Schedule 10.

Q. HOW DID THE COMPANY QUANTIFY THE POTENTIAL REDUCTION IN COMMODITY BAD DEBT EXPENSE?

A. Due to the manual nature of the existing disconnect for non-payment process, the Company is not able to complete all the physical disconnections for non-payment orders issued in a given year. As described above, the Company plans to propose the use of the AMI remote disconnect capabilities in the future as approved by the Commission, with input from stakeholders. This would result in a reduction in commodity bad debt expense.

To quantify these benefits, the Company calculated the average commodity bad debt expense between the years 2014 through 2018, and estimates that an 8 percent reduction in residential customer commodity bad-debt expense could be realized. This estimate is consistent with data provided to the Federal Energy Regulatory Commission in other utilities' pre- and post-AMI deployment reporting. We looked at eight utilities comparable to Xcel Energy and calculated the average commodity bad debt expense reduction, comparing their post-AMI deployment reports to pre-AMI deployment reports. Our estimate is consistent with the average. I also note that the remote disconnect capability may also reduce non-commodity bad debt expense, but non-commodity bad debt makes up only a small portion of Customer Care's bad debt expense. Regardless, we have not assumed any benefit associated with non-commodity bad debt expense in the CBA.

As described above, with the necessary regulatory approvals, these benefits would be reflected in Customer Care's O&M budgets in the future as a reduction in bad debt expense. These reductions are included in the AMI cost benefit analysis as shown in Schedule 10.

G. Metrics and Reporting

Q. WHAT INFORMATION DO YOU PROVIDE IN THIS SECTION?

A. In this section I discuss the tracking and reporting of Customer Care's operational and quality of service metrics. For those metrics that we expect will be impacted by AGIS implementation, I discuss how the Company plans to track and report these metrics as AGIS is implemented. I also discuss our future service quality filings with the Commission, as we believe those proceedings provide the appropriate venue to ensure stakeholder input relative to the Company's service quality reporting.

Q. HOW DOES THE COMPANY CURRENTLY REPORT SERVICE QUALITY METRICS?

A. Like other utilities, the Company reports service quality metrics under Minn. R 7826, Electric Utility Standards, on safety, reliability, and service quality. The Company also has a Quality of Service Plan (QSP)[7] that includes additional metrics, specifies thresholds, and includes penalties for performance not meeting the thresholds. Our service quality tariff was established and has evolved over many years in proceedings before the Commission, and is the result of extensive stakeholder input and agreements. Given the process to establish those metrics and baseline performance thresholds, we propose to address any changes in a separate proceeding to allow for full stakeholder review and input on any changes that may be necessary.

Q. HOW DOES THE COMPANY EXPECT AMI DEPLOYMENT AND AMI FUNCTIONALITY WILL IMPACT THE CUSTOMER CARE SERVICE QUALITY METRICS?

A. We believe several metrics related to Customer Care in the Company's QSP may be impacted and should be reviewed and re-evaluated in light of an AMI deployment. The QSP metrics that could be impacted both during and after AMI rollout include: customer complaints; billing accuracy and timeliness; and telephone response time. Ms. Bloch discusses potential impacts to QSP metrics related to Distribution Operations in her testimony.

[7] See the Company's Minnesota Electric Rate Book, Section 6, General Rules and Regulations, Subsection 1.9, Service Quality.

Q. HOW COULD THE LEVEL OF CUSTOMER COMPLAINTS, AS MEASURED BY THE CUSTOMER COMPLAINT QSP METRIC, BE IMPACTED BY AMI DEPLOYMENT AND ENABLING AMI FUNCTIONALITY?

A. The Company will carefully plan and seeks to deliver a seamless and easy experience for customers as they receive their new electric meter and understand and use the information and insights it will provide. However, we recognize that some customer dissatisfaction, resulting in increased customer complaints, could occur as we visit 1.4 million customer premises to exchange electric meters. This meter deployment is not business as usual.

Q. DESCRIBE HOW THE CUSTOMER COMPLAINT QSP METRIC IS CALCULATED AND HOW IT WORKS TODAY.

A. Currently, the Company has a limit on the number of complaints per customer that can be filed with the Commission in a year. Exceeding the complaint limit of 0.2059 complaints per 1,000 customers carries a $1 million fine annually. The number of customers in this metric is measured by the total number of natural gas and electric meters reported annually to the Commission.

The complaint limit is based on historical performance, reflects past business practices, and does not consider fault. Every complaint filed by a customer counts against the Company's annual limit, regardless of whether the Company adhered to rules, tariffs, and reasonable business practices, or whether the complaint otherwise has any merit.

Q. HOW DOES THE COMPANY EXPECT AMI IMPLEMENTATION MAY IMPACT THE NUMBER OF CUSTOMER COMPLAINTS?

A. While the Company has not exceeded the complaint limit since the QSP has been in place, we believe this significant initiative to convert to AMI meters warrants consideration of how complaints will be counted against a QSP limit both during and after deployment. The Company has created complaint-type codes related to AMI that could be used for tracking AMI-related complaints during deployment. This could be used to monitor and exclude these complaints from the QSP limit during meter deployment. In addition, complaint levels could be impacted beyond meter deployment, especially concerning potential changes to collections practices if such changes are approved by the Commission through a later filing.

Q. HOW COULD BILLING ACCURACY AND TIMELINESS METRICS, AS MEASURED BY THE INVOICE ACCURACY AND INVOICE ADJUSTMENT TIMELINESS QSP METRICS, BE IMPACTED BY AMI DEPLOYMENT?

A. The large volume of meter exchanges that will occur during a mass meter deployment will generate billing exception work requiring manual intervention as described earlier. Exception work is normal and occurs during the course of business today. However, the volume of meter exchanges that will occur during AMI deployment and the time required to process the resulting exceptions could impact both the invoice accuracy and invoice adjustment timeliness metrics.

The Company believes that invoice accuracy and invoice adjustment timeliness could be impacted during deployment, but should not be impacted following that timeframe. The Company believes an exclusion to the QSP penalty for these two metrics may be appropriate during the deployment window. The Company could still report performance during the deployment for trending and transparency. The Company will closely monitor Billing Operations work during meter deployment and will determine whether staffing increases may be warranted.

Q. HOW COULD TELEPHONE RESPONSE TIME, AS MEASURED BY THE TELEPHONE RESPONSE TIME QSP METRIC, BE IMPACTED BY AMI DEPLOYMENT?

A. The telephone response time QSP metric measures the percent of calls into the Company's contact centers or business office that are answered within 20 seconds during a year.

While customers will be advised to contact the meter deployment vendor regarding meter deployment issues, we recognize that some customers will contact the Company's customer service number instead. This could increase call volume and impact telephone response time during meter deployment, which could adversely impact the telephone response time metric. It is also reasonable to assume that customers may have questions regarding their new meter, its functionality and how to use it, as well as any new rates that may impact them.

While there may be impacts to telephone response time during and after deployment, the level of that impact is not known at this time. Customer education is being carefully planned to inform customers about their new meter and its benefits to help answer questions at the time they are most likely to have them. A digital experience, including a customer portal, will be deployed for customers to use and interact with their enhanced usage data and insights as well. Mr. Gersack discusses the customer education plan and customer portal functionality.

The Company will monitor call center volume and performance and will make every effort to maintain the prompt telephone response time our customers receive from us today, which may require staffing increases not included in O&M budgets today. The Company proposes to address call center response time in our service quality report, to the extent this QSP metric may be impacted as we move through the AMI deployment process and actual deployment impacts become better known.

H. AGIS Customer Care Summary

Q. PLEASE SUMMARIZE YOUR TESTIMONY AS IT RELATES TO CUSTOMER CARE'S RESPONSIBILITIES WITH RESPECT TO IMPLEMENTATION OF THE AGIS INITIATIVE.

A. Implementation of the AGIS initiative, and specifically advanced metering technology and the communications network, will enable the availability of detailed and timely data, system automation, and communications enhancements that will impact and provide benefits for our customers and the Customer Care organization. The process changes enabled by advanced grid implementation will help reduce Customer Care O&M expenses in meter reading, and potentially other areas. Customer Care has plans in place with respect to customer service, meter reading, and billing during AMI deployment and beyond as future advanced grid capabilities are enabled.

Q. PLEASE SUMMARIZE THE COMPANY'S PLANS WITH RESPECT TO FUTURE FILINGS NECESSARY FOR AMI IMPLEMENTATION, AS WELL AS THOSE TO ADDRESS FUTURE CAPABILITIES AND IMPACTS OF AGIS.

A. The Company intends to submit the following future filings requesting necessary Commission approvals and eliciting stakeholder input:

- Opt-out provisions – requesting approval of the processes, cost structure, and tariffs necessary to allow customers to opt out of AMI meter installation (2020);
- AMI billing – requesting approval of a rule variance and any tariff changes necessary to enable AMI interval billing (2020);
- Future filing to enable remote connect/disconnect capabilities;
- Future filing to request approval of a pre-pay option for customers; and
- Future service quality reporting under Minnesota Rules (beginning April 1, 2022) and the Company's QSP (beginning May 1, 2022) to address any impacts to service quality metrics as a result of AGIS implementation.

VI. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Customer Care organization continues to achieve strong customer satisfaction results and effectively manage its O&M expense levels. It continues to perform favorably to other electric utilities in managing bad debt expense and the cost to perform overall Customer Care functions. Therefore, the Customer Care organization's overall O&M expenses, including commodity and non-commodity bad debt expense, are reasonable and should be approved. Finally, Customer Care is preparing to realize the benefits of

AMI deployment through reduced O&M costs for meter reading and improved service offerings to customers.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Résumé

Christopher C. Cardenas
Vice President, Customer Care
Xcel Energy
1800 Larimer Street, Suite 1500, Denver, Colorado

Current Responsibilities (2019 - Present)

Provides leadership and direction for the Company's customer care functions, including meter reading, field collection, billing, credit and collection, customer contact centers, and related business support functions.

Previous Positions

PPL Electric Utilities
2014 - 2018 Vice President, Customer Services

Time Warner Cable
2012 – 2014 Vice President, Customer Service Operations

Comcast Cable
2011 – 2012 Director, Customer Service

U.S. Cellular
2007 – 2010 Director, Customer Service Operations

Sprint
2001 – 2007 Senior Manager, Business Customer Support

Education

Bachelor's Degree, Business Administration in Finance, Texas Lutheran University; Master's Degree, Business Administration (Finance emphasis), Webster University

Business / Industry Activities

Chair, Customer Service Committee for Association of Edison Illuminating Companies (AEIC); Advisory Board, J.D. Power (Electric Utility Industry); Advisory Board, CS Week; Advisory Board, Utility Analytics Institute

NORTHERN STATES POWER COMPANY

SERVICE ADDRESS	ACCOUNT NUMBER		DUE DATE
CUSTOMER NAME STREET ADDRESS CITY ST ZIP CODE	51-1234567-8		08/06/2019
	STATEMENT NUMBER	STATEMENT DATE	AMOUNT DUE
	666666666	07/10/2019	$57.81

YOUR MONTHLY ELECTRICITY USAGE

DAILY AVERAGES	Last Year	This Year
Temperature	76° F	73° F
Electricity kWh	0.0	16.8
Electricity Cost	$0.39	$2.57

QUESTIONS ABOUT YOUR BILL?

See our website: xcelenergy.com
Email us at: Customerservice@xcelenergy.com

Call Mon - Fri 7 a.m.-7 p.m. or Sat 9 a.m.-5 p.m.

Please Call: 1-800-895-4999
Hearing Impaired: 1-800-895-4949
Español: 1-800-687-8778

Or write us at: XCEL ENERGY
PO BOX 8
EAU CLAIRE WI 54702-0008

Like us on Facebook · Follow us on Twitter

SUMMARY OF CURRENT CHARGES (detailed charges begin on page 2)

Electricity Service	06/14/19 - 07/09/19	421 kWh	$64.36
Current Charges			**$64.36**

ACCOUNT BALANCE *(Balance de su cuenta)*

Previous Balance	As of 06/14	$563.95
Payment Received	Check 06/26	-$563.95 **CR**
	Check 06/18	-$6.55 **CR**
Balance Forward		**-$6.55 CR**
Current Charges		$64.36
Amount Due *(Cantidad a pagar)*		**$57.81**

028400 1/2

INFORMATION ABOUT YOUR BILL

Thank you for your payment.

Call *before* you move

If you're moving, remember to contact us in advance so we can stop your natural gas and electricity billing at your current address and start service, if needed, at your new one. Save yourself money and ensure a smooth transition to your new place. Please call or submit your changes at xcelenergy.com up to 45 days in advance.

RETURN BOTTOM PORTION WITH YOUR PAYMENT • **PLEASE DO NOT USE STAPLES, TAPE OR PAPER CLIPS**

ACCOUNT NUMBER	DUE DATE	AMOUNT DUE	AMOUNT ENCLOSED
51-1234567-8	08/06/2019	$57.81	

Please see the back of this bill for more information regarding the late payment charge. Pay on or before the date due to avoid assessment of a late payment charge.
Make your check payable to XCEL ENERGY

AUGUST						
S	M	T	W	T	F	S
				1	2	3
4	5	6	7	8	9	10
11	12	13	14	15	16	17
18	19	20	21	22	23	24
25	26	27	28	29	30	31

11

------ manifest line ---------

CUSTOMER NAME
STREET ADDRESS
CITY ST ZIP CODE

XCEL ENERGY
P.O. BOX 9477
MPLS MN 55484-9477

31 000000643600000005781

SERVICE ADDRESS	ACCOUNT NUMBER		DUE DATE
CUSTOMER NAME STREET ADDRESS CITY ST ZIP CODE	51-1234567-8		**08/06/2019**
	STATEMENT NUMBER	STATEMENT DATE	AMOUNT DUE
	666666666	07/10/2019	**$57.81**

SERVICE ADDRESS: STREET ADDRESS CITY ST ZIP CODE
NEXT READ DATE: 08/09/19

ELECTRICITY SERVICE DETAILS

PREMISES NUMBER: 300000000
INVOICE NUMBER: 0777777777

METER READING INFORMATION			
METER 66666666	Read Dates: 06/14/19 - 06/14/19 (0 Days)		
DESCRIPTION	CURRENT READING	PREVIOUS READING	USAGE
Total Energy	26175 Actual	26175 Estimate	0 kWh

METER READING INFORMATION			
METER 999999999	Read Dates: 06/14/19 - 07/09/19 (25 Days)		
DESCRIPTION	CURRENT READING	PREVIOUS READING	USAGE
Total Energy	421 Actual	0 Actual	421 kWh

ELECTRICITY CHARGES — RATE: Residential Service

DESCRIPTION	USAGE UNITS	RATE	CHARGE
Basic Service Chg			$6.67
Energy Charge Summer	421 kWh	$0.103010	$43.37
Fuel Cost Charge	421 kWh	$0.026318	$11.08
Decoupling Adj	421 kWh	- $0.001625	- $0.68 **CR**
Res Savers Switch AC			- $8.18 **CR**
Affordability Chrg			$0.81
Resource Adjustment			$3.02
Subtotal			**$56.09**
City Fees			$3.75
Transit Improvement Tax		0.50%	$0.30
County Tax		0.15%	$0.10
State Tax		6.875%	$4.12
Total			**$64.36**

INFORMATION ABOUT YOUR BILL

For an average residential customer, 51% of your bill refers to power plant costs, 11% to high voltage line costs and 38% to the cost of local wires connected to your home.

THANKS, MINNESOTA.

Our Minnesota customers have electric bills that are 22 percent lower than the national average. Thank you for supporting our investments in clean energy and participating in our energy efficiency programs.

Learn more at **xcelenergy.com/KeepingCostsLow**.

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Avoided O&M Meter Reading Costs																			
Drive-by Meter Reading Cost - O&M	2,155	86,393	1,085,789	2,460,063	3,740,671	3,587,859	4,153,792	4,287,938	4,426,475	4,562,493	4,702,691	4,847,197	4,996,143	5,149,667	5,307,907	5,471,011	5,639,126	**64,507,370**	**33,455,306**
TOTAL - Reduction in Meter Reading Costs	***2,155***	***86,393***	***1,085,789***	***2,460,063***	***3,740,671***	***3,587,859***	***4,153,792***	***4,287,938***	***4,426,475***	***4,562,493***	***4,702,691***	***4,847,197***	***4,996,143***	***5,149,667***	***5,307,907***	***5,471,011***	***5,639,126***	***64,507,370***	***33,455,306***
TOTAL O&M BENEFITS	**2,155**	**86,393**	**1,085,789**	**2,460,063**	**3,740,671**	**3,587,859**	**4,153,792**	**4,287,938**	**4,426,475**	**4,562,493**	**4,702,691**	**4,847,197**	**4,996,143**	**5,149,667**	**5,307,907**	**5,471,011**	**5,639,126**	**64,507,370**	**33,455,306**
OTHER BENEFITS																			
Cost reductions																			
Reduced Consumption on Inactive Meters	0	0	0	0	350,052	714,596	1,458,776	1,488,973	1,519,795	1,551,255	1,583,366	1,616,141	1,649,595	1,683,742	1,718,595	1,754,170	1,790,482	**18,879,538**	**9,235,364**
Reduced Uncollectible / Bad Debt Expense	0	0	0	0	259,816	538,078	1,114,360	1,153,920	1,194,884	1,237,303	1,281,227	1,326,711	1,373,809	1,422,579	1,473,081	1,525,375	1,579,526	**15,480,670**	**7,493,278**
Theft / Tamper Detection & Reduction	0	0	0	0	847,310	1,729,700	3,531,009	3,604,101	3,678,706	3,754,855	3,832,580	3,911,915	3,992,891	4,075,544	4,159,908	4,246,018	4,333,911	**45,698,446**	**22,354,455**
TOTAL - Cost Reductions	0	0	0	0	1,457,178	2,982,374	6,104,146	6,246,994	6,393,385	6,543,412	6,697,173	6,854,766	7,016,295	7,181,865	7,351,584	7,525,563	7,703,918	***80,058,654***	***39,083,097***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,457,178**	**2,982,374**	**6,104,146**	**6,246,994**	**6,393,385**	**6,543,412**	**6,697,173**	**6,854,766**	**7,016,295**	**7,181,865**	**7,351,584**	**7,525,563**	**7,703,918**	**80,058,654**	**39,083,097**
GRAND TOTAL BENEFITS	**2,155**	**86,393**	**1,085,789**	**2,460,063**	**5,197,849**	**6,570,233**	**10,257,938**	**10,534,932**	**10,819,860**	**11,105,905**	**11,399,864**	**11,701,963**	**12,012,439**	**12,331,532**	**12,659,491**	**12,996,574**	**13,343,044**	**144,566,024**	**72,538,404**

Direct Testimony and Schedules
Ravikrishna Duggirala

Before the Minnesota Public Utilities Commission
State of Minnesota

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

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

Advanced Grid Cost Benefit Analysis

November 1, 2019

Table of Contents

Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Ravikrishna Duggirala. I am the Director of Risk Strategy for Xcel Energy Services Inc. (XES), the service company affiliate of Northern States Power Company, a Minnesota corporation (NSPM or the Company) and an operating company of Xcel Energy Inc. (Xcel Energy).

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I joined Xcel Energy in 2002, and have held my current position, in which I am responsible for Enterprise Risk Management, Asset Risk Management, risk analytics, and modeling, since 2008. Previously, I was the Manager of Energy Sales Risk for XES, where I was responsible for retail sales risk analysis, key risk analysis, sensitivity analysis, and risk analytics. I was also a Risk Consultant at Xcel Energy between 2002 and 2005. I received my Ph.D in Engineering from Purdue University in 1996, and my Master's Degree in Business Administration from Washington University in St. Louis in 2000. My Statement of Qualifications is provided as Exhibit___(RD-1), Schedule 1.

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

A. The purpose of my Direct Testimony is to present the Company's overall assessment of the costs and quantifiable benefits of the future components of its Advanced Grid Intelligence and Security (AGIS) initiative. I present the structure of the Company's overall cost benefit model, which is provided with the Company's AGIS supporting files compact disc in Volume 2B of this filing. I identify its purpose as one tool to utilize in assessing the quantifiable costs and benefits of the Company's overall plans for the AGIS initiative. I also support specific types of benefits in the model, which include avoided peak capacity and customer savings resulting from the implementation of time-of-use rates with our Advanced Metering Instructure (AMI) component of AGIS. Additionally, I summarize some of the qualitative benefits that are difficult to capture in a quantitative model.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony supports the Company's cost benefit model for the AGIS initiative, which was required by the Minnesota Public Utilities Commission (Commission) for our advanced grid planning. Overall, I explain why the model is appropriate and presents a reasonable comparison of the costs and quantifiable benefits of the future components of the AGIS initiative from the customer perspective. I note that the model has some limitations, in that it only presents costs and benefits that the Company has converted to dollars – whereas some benefits (like customer satisfaction) cannot be quantified, and the Company is not comfortable attaching a cost basis to other benefits (like human safety). As such, the cost benefit analysis (CBA) is simply one useful tool to assess certain aspects of the Company's proposed AGIS initiative.

In my Direct Testimony, I begin by introducing the structure of, and our approach to the model. I explain that the model is intended to present a conservative comparison of the net present value (NPV) of the costs of the components of the AGIS initiative with the NPV of benefits of those components, on a revenue requirements basis. The model also presents a composite NPV comparison between costs and benefits of the overall AGIS initiative. I identify the cost and benefit inputs, stated in terms of capital, operations and maintenance (O&M), or other benefits. While I present these inputs within the cost benefit model itself, the costs and benefits are largely supported by our business area witnesses, namely Mr. David C. Harkness on Information Technology (IT) components, Ms. Kelly Bloch on Distribution Operations, Mr. Michael Gersack on Program Management, and Mr. Christopher Cardenas on Customer Care. These witnesses support costs and benefits for each component of the AGIS initiative (AMI, Fault Location Isolation and Service Restoration (FLISR), Integrated Volt-VAr Optimization (IVVO), and associated components of the Field Area Network (FAN)). In my testimony, I identify where information about the costs and benefits can be found. I also support the aspects of our modeling assumptions related to avoided peak capacity and peak pricing avoidance as a result of AMI, and reduced carbon emissions as a result of AMI and IVVO, illustrating why those assumptions are reasonable.

Next, I provide the ranges of results of the Company's CBA for each of the components of the AGIS initiative, as well as the overall AGIS CBA. Our model results in a ratio of estimated benefits to costs for each component, as well as the composite ratio of estimated benefits to costs for the overall initiative. A ratio of 1.0 or higher indicates quantifiable benefits are expected to equal to or exceed the costs, whereas a ratio of less than 1.0 indicates costs are expected to exceed quantifiable benefits:

Table 1
Range of AGIS Benefit-to-Cost Ratios[1]
(Includes allocated components of FAN)

	<u>Low Sensitivity</u> *IVVO 1.0% Energy Savings, With Contingency*	<u>Baseline</u> *IVVO 1.25% Energy Savings, With Contingency*	<u>High Sensitivity</u> *IVVO 1.5% Energy Savings, No Contingency*
AMI	0.83	0.83	0.99
FLISR	1.31	1.31	1.53
IVVO	0.46	0.57	0.72
Overall AGIS	**0.86**	**<u>0.87</u>**	**1.03**

I also provide discussion regarding the limitations of a cost benefit model, both with respect to unquantifiable qualitative benefits and in relation to the need to update aging distribution infrastructure that is a central requirement of an electric service delivery business. While Company witnesses Mr. Gersack and Ms. Bloch describe those benefits in their testimony, I provide context for these unquantifiable benefits and explain how they support the Company's overall advanced grid strategy.

Finally, I provide "Least-Cost/Best-Fit" summaries of the relative functions, limitations, costs, and benefits (to the extent applicable) for metering and communications network alternatives. These comparisons underscore why we have selected our AMI and FAN solutions, as described in extensive detail in the testimony of Ms. Bloch and Mr. Harkness.

Overall, I conclude that the Company's cost benefit model is one reasonable means of assessing quantifiable costs and benefits of the overall AGIS

[1] The Overall AGIS ratio is not intended to be a sum or simple average of other ratios, but rather is a consolidated ratio as I discuss in Section II.C of my Direct Testimony.

initiative, but a comprehensive assessment requires consideration of additional factors that are discussed by the Company's other AGIS witnesses.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. I present the remainder of my testimony in the following sections:

- Section II: AGIS Quantitative Cost Benefit Model
- Section III: Least-Cost/Best-Fit Alternatives
- Section IV: Qualitative Benefits of AGIS
- Section V: Conclusion

II. AGIS QUANTITATIVE COST BENEFIT MODEL

A. Model Structure and Requirements

Q. WHAT IS THE PURPOSE OF THE AGIS CBA, FROM THE COMPANY'S PERSPECTIVE?

A. The Company is presenting its CBA to illustrate its assessments of the quantitative value of the requirements for and benefits of the AGIS initiative. This model is intended to aid the Commission and other stakeholders in evaluating the overall prudence of the AGIS proposals, and was likewise required by the Commission's Order Point 9.B in its Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements, dated September 27, 2019 in our 2017 Transmission Cost Recovery (TCR) rider (Docket No. E002/M-17-797) (TCR Rider Order).

Q. PLEASE INTRODUCE THE COMPANY'S COST BENEFIT MODEL IN THIS MATTER.

A. The CBA model compares the costs with the quantifiable benefits of each component of the Company's AGIS initiative, as well as the overall costs and quantifiable benefits of the initiative. More specifically, the model calculates the benefit-to-cost ratios for the proposed components of the AGIS initiative that the Company is planning to pursue at this time – namely, AMI, FLISR, and IVVO. The cost components of the FAN are also incorporated into the CBA because the FAN benefits are realized through its support of the other components of the AGIS initiative. The CBA utilizes specific cost and quantifiable benefit estimates and assumptions provided by Company witnesses Mr. Gersack, Ms. Bloch, Mr. Harkness, and Mr. Cardenas. I also support certain benefits, as discussed later in my Direct Testimony.

The Company's CBA model utilizes the Discounted Cash Flow (DCF) procedure and the 2019 Net Present Value (NPV) for quantifiable costs and benefits, to determine the value of the AGIS investments. Specifically, the benefit-to-cost ratio evaluates the standalone costs and benefits of each of AMI, IVVO, and FLISR respectively, including the FAN costs allocated to each of these components. Finally, the model evaluates the NPV benefit-to-cost ratio for AMI, IVVO, and FLISR on a combined basis.

Q. HOW WAS THE COST BENEFIT MODEL DEVELOPED?

A. The structure and form of the CBA are consistent with the Company's general approach to CBAs, including the CBA provided to the Colorado Public Utilities Commission in our Public Service Company of Colorado AGIS Certificate of Public Convenience and Necessity (CPCN) proceeding. (That matter, Proceeding No. 16A-0588E, resulted in an unopposed settlement approving the Company's need for the components of AGIS for which it needed a CPCN.) In structuring the CBA for grid modernization investments specifically, we also looked at similar analyses conducted by others for similar types of assets. For example, our framework is similar to that used by Ameren Illinois in their grid modernization efforts. We also considered the Electric Power Research Institute (EPRI's) technical report on Estimating the Costs and Benefits of the Smart Grid.[2]

Q. WHY DID THE COMPANY SELECT THIS FORM OF QUANTITATIVE MODEL?

A. This CBA is just one phase of a much more extensive assessment performed by the Company prior to seeking Commission approval for the four AGIS components presented in this case. This assessment included evaluation of the needs and goals of our distribution system, customers, the Commission, and other stakeholders, and then assessments of the alternatives to meet those needs and goals. These processes are described in detail in the testimony of Company witnesses Mr. Gersack, Ms. Bloch, Mr. Cardenas, and Mr. Harkness. (For example, Ms. Bloch and Mr. Cardenas explain the status of the current meters on our system and the extensive planning, information gathering, RFP processes, and consideration of alternate vendors, devices, systems, and programs that we undertook prior to selecting our current AMI plan.[3]) Now, as we are at the point of proposing our overall strategy and plan to the Commission, we provide this cost benefit model to identify and discuss the cost-effectiveness of the components of that plan (including the avoided costs of necessary alternative solutions) and of the total AGIS initiative.

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[2] https://www.smartgrid.gov/files/Estimating_Costs_Benefits_Smart_Grid_Preliminary_Estimate_In_201103.pdf.

[3] To the extent it makes sense, I have summarized these considerations in the least-cost/best-fit segment later in my testimony, which illustrates our conclusions with respect to alternatives to AMI and the FAN.

Q. HOW DID THE COMPANY STRUCTURE THE CBA PRESENTED IN YOUR TESTIMONY?

A. The model compares the upfront and ongoing project implementation costs (including planning and installation), as well as avoided costs, against the quantifiable benefits of the Company's proposed project over the analysis period. The model incorporates the Distribution costs and Customer Care costs of the systems, as well as the Business Systems costs required for the implementation of the projects, including integration, software-hardware, project management, and other costs in order to provide a complete picture of AGIS initiative costs.

Further, the model views costs and benefits from the customer perspective, meaning that it quantifies the estimated net impact of costs and savings to customers, including Commission-approved measures of societal benefits.[4] In this respect, all quantifiable utility costs and benefits were estimated in the model as they would be effectuated through utility electric rates. For example, the Company estimated the total cost of meter installation and operation in terms of revenue requirements.

We also estimated reasonably quantifiable direct customer benefits of improvements in the Company's electric service. These benefits can take many different forms, such as cost savings in system management or reduced energy and generation needs that benefit the customer through rates; pricing opportunities for customers through time-of-use rates; reduced outage impacts to customers' own activities; and avoidance of lost revenue through

[4] For example, carbon dioxide emission reductions can be measured and quantified via the Commission-ordered externality values.

meter tampering. In measuring such benefits, we took into account past Commission determinations of value (as with the social cost of carbon, as described in my testimony) and feedback on previous submissions (as with the CMO values, as described in Ms. Bloch's testimony).

Q. ONCE THE QUANTIFIABLE COSTS AND BENEFITS FROM THE OTHER WITNESSES ARE IN THE MODEL, WHAT CALCULATIONS DOES THE MODEL MAKE TO ESTIMATE THE CUSTOMER IMPACT?

A. First, it is necessary to take the projected capital costs and benefits and estimate a net capital revenue requirement. The net capital revenue requirement is the aggregate impact of both the capital costs and the capital savings over the analysis period. Therefore, the net capital revenue requirement estimates how the capital related costs and benefits would impact the customer through electric rates.

The model takes the annual capital costs and capital benefits and makes assumptions regarding how those costs and benefits may be reflected in rate base, and estimates a net capital revenue requirement as a function of depreciable book and tax lives for the assets, as well as the Company's weighted average costs of capital (WACC) and tax rates. The estimated net revenue requirement associated with the capital costs and benefits represents the annual impact of the capital spend, which is how the Company would calculate electric rate recovery on the underlying investment.

Second, for O&M costs and savings, fuel savings, and other benefits, the model assumes that those costs and benefits would be expensed or earned in the year they were incurred, and are embedded in the Company's electric rates. Any such changes will flow through to the customers.

Q. HOW DOES THE MODEL CONVERT THE ESTIMATES OF NET CAPITAL REVENUE REQUIREMENT, O&M COSTS, AND BENEFITS TO A BENEFIT-TO-COST RATIO?

A. Once the stream of the net capital revenue requirements, O&M costs and benefits are calculated, the streams are compared on an NPV basis. Each stream of costs or benefits is present-valued back to 2019 dollars utilizing the Company's WACC as a discount rate. Then, by dividing the net present value of benefits by the net present value of costs, a benefit-to-cost ratio is calculated. A benefit-to-cost ratio of 1.0 indicates benefits of that component of the AGIS initiative – or of the overall initiative – equal costs; a ratio of less than 1.0 means costs exceed benefits; and a ratio of greater than 1.0 means benefits exceed costs.

Q. PLEASE DESCRIBE THE PERIOD OF TIME THE MODEL EXAMINES.

A. The model for AMI (including the TOU Pilot) examines the period beginning in 2019 and ending 2035. The period for IVVO and FLISR is longer (2019 through 2038), due to the longer useful life of the underlying assets.

Q. WHY DOES THE MODEL EXAMINE THESE PERIODS OF TIME?

A. For AMI, the model reflects the current phase of work beginning in 2019, and future installation phases beginning in 2021, as described by Ms. Bloch. This includes the assumption that AMI meters and associated software and hardware, as well as the necessary components of the FAN will begin depreciation upon installation. It also includes the meters we are installing for 2019 and 2020 for the TOU pilot evaluation period, which will subsequently be replaced with meters with Distributed Intelligence capabilities at no cost to the Company or customers.

While additional meters will be installed after 2021, the IT components will need to be in place by the time of the initial meter installations in order for the system to function. Thus by 2035 (after the fifteen-year period from 2021-2035), the network will be fully depreciated. Additionally, while the potential service life of AMI meters is between 15 and 20 years in the industry, we have utilized a fifteen-year period for AMI examination. This is consistent with the 15-year depreciation terms presently approved by the Commission for our existing automated meter reading (AMR) meters and reflects the challenging climate in Minnesota.

As Ms. Bloch further describes, the FLISR and IVVO assets are expected to have a 20-year life. The twenty-year life for IVVO and FLISR follows the industry standard for the life cycle evaluation of similar projects. While FLISR and IVVO devices will be installed beginning in 2020 and 2021 respectively, as with AMI the underlying IT systems must be in place before device installation. As a result, the 2019-2038 IVVO and FLISR CBA timelines capture the estimated costs and benefits from installation for the projected life of the system.

While some of the distribution assets installed may be useful beyond this timeframe, overall, our timeframes are intended to be conservative and therefore support a conservative assessment of total benefits and costs.

Q. CAN YOU PROVIDE MORE INFORMATION ON HOW THE COMPANY DEVELOPED THE COST AND BENEFIT INPUTS INTO THE MODEL?

A. Yes. The capital and O&M costs and benefits of AMI (including the TOU pilot), FLISR, and IVVO, including the associated FAN components, were determined by our Customer Care, Business Systems, and Distribution areas (including business area financial teams), with additional support from the AGIS Program Management Office, as discussed in more detail below. Our Program Management Office, Risk Management, and the Regulatory Department coordinated and developed modeling assumptions consistent with these cost and benefit estimates. The testimonies of Mr. Gersack, Ms. Bloch, Mr. Harkness, and Mr. Cardenas provide detail regarding the cost and benefit assumptions for each component of the AGIS projects, while I summarize those model inputs and provide explanations on the overall results of our CBAs.

Q. WHY DO YOU REFER TO AMI, FLISR, AND IVVO COSTS AND BENEFITS AS "INCLUDING THE ASSOCIATED FAN COMPONENTS"?

A. As Company witnesses Ms. Bloch and Mr. Harkness discuss in their Direct Testimony, the FAN will be a single, general-purpose, field area wireless networking resource that enables two-way communication of information and data to and from infrastructure at the Company's substations and the field devices. The FAN will provide the necessary communication capacity for the AGIS initiative, while also ensuring that the data being transmitted is secure. However, the FAN is not a standalone program and does not provide benefits on its own; rather, it is the communications network to enable AMI, IVVO, and FLISR functionality and provide their respective benefits to customers.

As such, we have incorporated FAN costs into the models for AMI, FLISR, and IVVO.

Q. HOW WERE THE FAN COMPONENTS THEN INCORPORATED INTO THE MODEL?

A. The model allocated FAN costs across the analyses for the individual AGIS components the FAN serves. Specifically, as explained by Mr. Harkness in his Direct Testimony, the FAN structure is primarily made up of two technological modules: WiMAX and WiSUN. WiMAX (Worldwide Interoperability for Microwave Access) is used to transfer data over different transmission modes such as point to point and multipoint modes. WiSUN (Smart Utility Network) is a low rate wireless system that must be in place to enable AMI device-to-device and device-to-headend communication. Because AMI is the predominant beneficiary of the WiSUN system, WiSUN costs have been completely allocated to AMI.

The meters and repeaters that constitute the AMI, the IVVO capacitors and voltage monitors, and the FLISR reclosers will each have embedded communication modules that will allow them to communicate directly with the FAN's access points on the WiMAX core infrastructure. But while the WiMAX system will provide coverage for all of NSPM's service territory, including 1050 feeders that all will contain AMI meters, Ms. Bloch explains that only a subset of the feeder population will have FLISR and IVVO equipment installed. Specifically, FLISR equipment will be initially installed on 208 feeders, while IVVO will be installed on 189 feeders. Likewise, each program will benefit from the communication system based proportionally on the amount of data needed and transferred. WiMAX costs are therefore distributed between AMI, FLISR, and IVVO according to the number of devices in proportion to the number of feeders.

Based on the total number of devices installed by feeder for each program, and given that additional devices affecting the WiMAX component may be installed in the future for both IVVO and FLISR, the business has estimated an allocation to capture that growth of AMI at 80 percent, IVVO at 5 percent, and FLISR at 15 percent. These percentages are also consistent with the total initial capital investment required by each program.

Consequently, the AMI, IVVO, FLISR, and consolidated models assume implementation of the FAN from 2019 through 2024, consistent with the timeline to subsequently implement the AMI meters, IVVO, and FLISR assets.

Q. CAN YOU ALSO PROVIDE MORE DETAIL AS TO HOW THE IT COMPONENTS ARE INCORPORATED INTO THE MODEL?

A. Yes. As described by Company witness Mr. Harkness, IT efforts include the costs of integrating the components of the AGIS initiative with existing Company back-end applications that will utilize the data. Similarly, IT efforts are necessary to ensure the security of the data collected and transmitted from advanced metering. As with the FAN, IT work is not a standalone program that provides benefits on its own; rather, it is a necessary component of the AGIS programs. Therefore, the costs of IT efforts for AMI, FLISR, and IVVO are included in the cost benefit model for these components.

Q. WHY IS THE CBA FOCUSED ON AMI (INCLUDING THE TOU PILOT), FLISR, AND IVVO, WITH ASSOCIATED COMPONENTS OF THE FAN?

A. These are the components of the AGIS initiative that are forward-looking, and which the Company plans to undertake as an integrated plan for the advancement of our distribution system. While they build on the Advanced Distribution Management System (ADMS), the ADMS was previously approved by the Commission through Docket No. E002/M-15-962 under Minn. Stat. § 216B.2425, before other components of the AGIS initiative were submitted or approved, and is necessary regardless of other selected advanced grid efforts. Consequently, the CBA is structured to aid the Commission's decision-making for the future, both from rate recovery and Integrated Distribution Planning (IDP) perspectives.

Q. HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR THE FIRST FIVE-YEAR PERIOD, FROM 2019 THROUGH 2023?

A. Each subject matter expert provided estimated capital and O&M costs and benefits in 2019 dollars, by year, for the period 2019 through 2023. The dollars for 2020-2022 align with the Company's multi-year rate plan (MYRP) in this proceeding (plus one year).

These costs and benefits, except for fixed price items, were then converted into nominal dollars within the model using assumptions for labor and non-labor inflation over the analysis period.

Q. HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR 2024 THROUGH 2038?

A. The additional capital and O&M costs beyond 2023 were estimated for each respective part of the project through 2035 for AMI and 2038 for IVVO and FLISR, in order to capture the costs and benefits of each of the programs beyond the initial implementation period. These O&M and capital costs were provided in 2019 dollars by or at the direction of Company witnesses Mr. Gersack, Ms. Bloch, and Mr. Harkness, and were escalated to nominal dollars for either the full twenty-year (FLISR, IVVO) or fifteen-year (AMI) analysis period.

Benefits were also estimated for this period based on when we expect customers to experience these benefits, including continued escalation of benefits beginning in 2023 or earlier to the appropriate future year.

Q. HAVE THE COSTS LISTED IN THE MODEL BEEN CORRELATED TO THE COMPANY'S RATE CASE BUDGET?

A. Yes. My group worked closely with the Financial Planning area to ensure that the two are consistent. However, it is important to be clear that there are some differences in how the numbers are presented. In particular, the analysis is based on net present value of revenue requirements, with capital investment costs captured in the year the investment is in service and costs stated in 2019 dollars. The MYRP budgets presented by other AGIS witnesses are stated in annual capital expenditure and capital addition dollars. As a result, the numbers in the CBA correspond to the rate case budgets but will not look exactly the same.

Q. HOW ARE THE COSTS IN THE MODEL CATEGORIZED?

A. It is possible to review the costs in the model from several perspectives. The costs, which are set forth in Exhibit___(RD-1), Schedules 2, 3, 4 and 5 of my Direct Testimony, are identified as:

- Rate case budgets to the extent they are for the years of the Company's MYRP, or longer-range planning costs for the years after 2022;
- Either capital or O&M;
- Either Business Systems or Distribution costs; and
- Direct, Indirect, Tangible, or Intangible costs, consistent with Order Point A.3 in the Commission's September 27, 2019 TCR Rider Order.

Q. PLEASE PROVIDE THE COMPANY'S DEFINITIONS OF DIRECT, INDIRECT, TANGIBLE, INTANGIBLE, AND "REAL" COSTS FOR PURPOSES OF ITS AGIS INITIATIVE.

A. The Company defines these categories of costs as follows:

- *Direct costs* – the cost of the materials and the workers that are involved when a company makes a particular product or provides a particular service that can be easily traced to that product, department, or project – similar to costs that are assigned rather than allocated.
- *Indirect costs* – a cost that cannot be directly traced to a particular product, department, activity, project, or providing a particular service – similar to overhead, or costs that are allocated rather than assigned.
- *Tangible costs* – Like direct costs, a tangible cost (or benefit) is a quantifiable cost related to an identifiable source or asset. It can be directly connected to a material item used to conduct operations or run a business. Tangible costs represent expenses arising from such things

as purchasing materials, paying employees or renting equipment. The costs in the CBA are tangible.

- *Intangible costs* – an unquantifiable cost (or benefit) relating to an identifiable source. Intangible costs represent a variety of expenses such as losses in productivity, customer goodwill, drops in employee morale, or damage to corporate reputation. Most qualitative costs and benefits are intangible, although the Company has chosen not to assign a dollar value to some potentially tangible costs (like human safety).
- *Real costs* – total costs the utility incurs to produce a good or service or to implement a program, including the cost of all resources used and the cost of not employing those resources in alternative uses. Real costs analysis gives a greater picture of a product and the spending associated with it. The CBA model is intended to identify Real Costs throughout.

These categories do at times overlap, as most tangible costs are also assigned or allocated and are therefore either an Indirect or Direct cost. Where overlap occurs in the Company's AGIS modeling, both categories are identified.

Q. ARE INTERNAL AND EXTERNAL LABOR COSTS INCLUDED IN THE COSTS OF EACH COMPONENT OF THE AGIS INITIATIVE INCLUDED IN THE MODEL?

A. Yes. As Mr. Gersack discusses, both the model and our overall support for the AGIS initiative in this proceeding are intended to capture the "all-in" costs of the project. Further, the Company is seeking base rate recovery for project costs being incurred or placed-in service during the MYRP; therefore, it is appropriate to include both internal and external labor costs. The support for these costs is provided by Ms. Bloch and Mr. Harkness.

Q. DO THE COST INPUTS FOR AMI, FLISR, AND IVVO INCLUDE CONTINGENCY ASSUMPTIONS?

A. Yes. In addition to the cost estimates, the Distribution and Business Systems areas developed contingency estimates for each aspect of the project that warranted a contingency. These contingency estimates are depicted on Exhibit___(RD-1), Schedule 2 (AMI CBA Summary), Schedule 3 (FLISR CBA Summary), and Schedule 4 (IVVO CBA Summary) as cost line items. Since by definition the amount and type of contingency dollars that will actually be spent cannot be wholly defined up front, the Company prepared CBAs summaries for each component both with and without contingency dollars, to provide insight into how the range of potential contingency amounts could affect the overall benefit-cost ratio. The testimonies of Ms. Bloch, Mr. Harkness, and Mr. Gersack provide additional support for the contingency amounts included in the CBA.

Q. HOW WERE THE ESTIMATES OF CONTINGENCY FOR EACH WORK STREAM INTEGRATED INTO THE MODEL?

A. The estimates of contingency were added to the estimated costs of the project and input into the model as a cost. In essence, the model evaluates the cost of the project as if the Company needed to spend up to the full contingency amounts or none of the contingency. This allows both the most conservative view of potential benefit-to-cost ratios (all contingency used), as well as the greatest calculated benefit-to-cost ratio, providing a view of range of potential outcomes.

Q. WHAT STEPS DID THE COMPANY UNDERTAKE TO VERIFY THAT THE MODEL IS STRUCTURALLY SOUND?

A. The model structure was based on models and similar analyses undertaken by the Company and other utilities in support of similar AMI and grid advancement programs. A number of business areas within the Company, including Regulatory Administration, Risk, Corporate Development, Capital Asset Accounting, Revenue Requirements, Demand Side Management, Business Systems and Distribution, subsequently collaborated to develop and ensure the model incorporated requirements necessary to properly estimate the known and quantifiable life cycle value proposition.

Q. OVERALL, IS THIS CBA AN APPROPRIATE TOOL FOR EVALUATING THE QUANTIFIABLE ASPECTS OF THE AGIS INITIATIVE?

A. Yes. By developing the model from the customer's perspective, the Company is providing clear and comprehensive information about the overall quantifiable impact of implementing these programs to customers. By this we mean that the CBA includes benefits that can be both quantified generally and stated in terms of a reasonably calculable dollar value.

The cost benefit model also provides a high-level look at the costs versus the quantifiable benefits of the overall AGIS initiative for customers, as well as a more detailed breakdown of individual costs and benefits assumptions for each program. However, the cost benefit model does not address all reasons for undertaking the AGIS program or the benefits of the program because many such reasons and benefits cannot be quantified or reduced to a dollar value. Therefore, the cost benefit model provides an appropriate perspective on the quantifiable costs and benefits of the program but not on all relevant considerations.

Q. WHY DO YOU SAY THE MODEL PROVIDES AN APPROPRIATE PERSPECTIVE ON QUANTIFIABLE CONSIDERATIONS?

A. Because a CBA is, by definition, intended to quantify costs and benefit, it can only capture the quantifiable. As discussed later in my testimony, examples of benefits that were not quantified include customer satisfaction, customer choice, planning and control of the grid, greater hosting capacity, job creation, improved quality of service delivered, and safety, among others described by Ms. Bloch, Mr. Cardenas, Mr. Gersack, and myself. This is why the CBA is one tool, but it should not be regarded as a definitive analysis on the merits of AGIS, because it cannot consider factors that are qualitative or on which the Company has not put a price (like human safety).

In addition, a model based on measureable considerations does not take into account any fundamental need for the infrastructure in question. For example, the Company must have meters in order to provide and bill for electric service. We therefore must plan for the pending expiration of the Cellnet AMR service contract while also taking into account that Xcel Energy is the last company using the Cellnet technology embedded in the Company's current meters. However, a cost versus benefit model cannot fully reflect that the primary function of updated meters is not necessarily to reduce the net cost of meters compared to aged technology, but rather to enable the utility to provide services to meet the needs and expectations of the customer.

Finally, while the model can and does reflect the costs of AMI versus AMR technology as an avoided cost alternative, it cannot fully assess whether it would be short-sighted or impracticable for the Company to replace aging technology with other aging technology, nor the effect of using older technology on unquantifiable customer expectations (like better outage and service restoration communications, and more timely energy consumption data) that is more dependent on advanced metering technology. All told, the model is a helpful assessment tool within the scope of its intended purpose. And because the Company has taken a conservative approach to modeling the benefits and costs of the AGIS strategy, we believe it is a reliable and helpful tool.

B. Quantitative Inputs

1. AMI Inputs

Q. WHAT ARE THE KEY COSTS AND BENEFITS OF AMI?

A. Company witness Ms. Bloch discusses the costs and benefits of AMI in detail in her testimony. At a high level, the benefits of AMI include: (i) providing more granular customer energy usage information that supports greater customer energy usage choice, pricing flexibility, and carbon reduction; (ii) reducing field and meter service and meter reading costs; (iii) reducing unaccounted for energy; (iv) assisting with identification of service outages and foster restoration; (v) providing voltage measurement information to assist in load flow and voltage calculations performed in the ADMS; (vi) serving as signal repeaters for other AMI meters and FAN network components; and (vii) improving infrastructure investment efficiencies. The purchase of AMI meters also enables the Company to retire the end-of-life Cellnet technology that will no longer be supported in the future (as described by Company witness Mr. Cardenas) and avoid the purchase of other, less functional advanced meter reading (AMR) meters in the near future. As discussed below, not all of the benefits of AMI are quantifiable or able to be reduced to a dollar value. In the cost benefit model, however, we have identified and captured the costs and quantifiable benefits associated with the technology.

The key costs of AMI include the meters themselves, including the labor cost of installation and testing, supporting FAN and IT resources, AMI program and management, and other supporting labor for operations.

Q. HOW WERE AMI CAPITAL COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the AMI program were developed by the Company's subject matter experts and are detailed in the Direct Testimonies of Ms. Bloch, Mr. Harkness, Mr. Gersack, and Mr. Cardenas, as set forth in Tables 2 through 6 below. My Exhibit ___ (RD-1), Schedule 2 provides a summary of each component of the quantifiable AMI costs and benefits, as they appear in the CBA.

Table 2

AMI Capital Costs

Capital Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Meters and Installation	Capital costs portion of AMI meter purchase and installation. Capital costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(D)(5)
Field Area Network (AMI)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
	Capital costs associated with installation of pole-mounted devices.	Direct Testimony of Ms. Bloch, Section V(E)(3)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of AMI.	Direct Testimony of Mr. Harkness, Section V(E)(3)(c)
Program and Change Management	Capital costs associated with internal management of AMI.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 3

AMI Capital Benefits

Capital Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved capital spend efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Avoided Meter Purchases for Failed Meters	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.	Direct Testimony of Ms. Bloch, Section V(D)(4)
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	Direct Testimony of Ms. Bloch, Section V(D)(4)

Q. HOW WERE AMI O&M COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. O&M estimates for the AMI program were likewise developed by the Company's other AGIS witnesses, as set forth in Tables 3,4, and 5 below.

Table 4

AMI O&M Costs

O&M Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Field Area Network (AMI) allocated portion	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of AMI.	Direct Testimony of Mr. Harkness, Section V(E)(3)(c)
AMI Operations (Personnel)	O&M costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(D)(5)
Program Management	O&M costs associated with internal change management and oversight for AMI.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 5

AMI O&M Benefits

O&M Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Avoided O&M Meter Reading Cost	O&M cost component of a drive-by meter reading system alternative to AMI, since current Cellnet system requires replacement	Direct Testimony of Mr. Cardenas, Section V(F)
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved O&M efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)

Table 6

Other Quantifiable AMI Benefits

Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Consumption Inactive Premise	Expedited ability to turn off power quickly when determined premise has been vacated.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible/bad debt.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Outage Duration	Direct benefit to customers associated with reduced outage duration.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Critical Peak Pricing	Customer demand savings in response to new rate structures.	Brattle Group Report, Exhibit ___ (RD-1), Schedule 6 and additional detail in this Section of my Direct Testimony
TOU Customer Price Signals	Difference in energy prices paid by consumers in response to new rate structures.	Integrated Resource Plan – RP-19-368 Appendix F2 and additional detail in this Section of my Direct Testimony
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to shifted load.	Additional detail in this Section of my Direct Testimony

Q. CAN YOU SUMMARIZE THE BENEFITS YOU DESCRIBE IN YOUR TESTIMONY?

A. Yes. As noted in Table 6 above, I discuss how the Company calculated AMI benefits associated with critical peak pricing and TOU customer price signals (combined, "load flexibility" benefits), as well as reduced CO_2 emissions. Exhibit ___ (RD-1), Schedule 5 identifies the quantification of these benefits for purposes of the CBA.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE COMPANY'S LOAD FLEXIBILITY ASSUMPTIONS?

A. Yes. 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), which is attached to my Direct Testimony as Exhibit___ (RD-1), Schedule 6. The Brattle Study developed quantification of the benefits of potential TOU and CPP rates, which were in turn incorporated into our CBA.[5] 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.

Q. WHY DID THE COMPANY RELY ON THE BRATTLE STUDY?

A. Brattle is a well-respected economic consulting and analytics firm, and conducted a similar study for Public Service Company of Colorado (Xcel Energy's Colorado utility operating company), in relation to its portion of the AGIS initiative. As a result, we have experience with this group and have found their studies to be robust and reasonable.

Q. PLEASE DESCRIBE THE TOU ASSESSMENT IN THE BRATTLE STUDY.

A. The Brattle Study assumes a static price signal with higher prices during the five-hour period around system peak on non-holiday weekdays, and models both opt-in and opt-out approaches to time of use rates.[6] Demand reduction

[5] I note that while Brattle modeled CPP rates and we have used this information in our CBA in this case, there are a variety of peak demand rate design structures the Company may explore, such as peak time rebates.

[6] Brattle Study at p.6.

grows modestly as TOU adoption and utilization expands. Based on these assumptions and the base case in the Brattle analysis, this rate has the potential to shift demand approximating 161 Megawatts (MW) for residential customers and 52 MW for medium commercial and industrial customers from on-peak to off-peak.[7] The overall result is cost savings to customers.

Q. WHAT ARE THE BENEFITS ASSOCIATED WITH CRITICAL PEAK PRICING?

A. The potential CPP rate "provides customers with a much higher rate during peak hours on 10 to 15 days per year."[8] CPP rates were modeled by Brattle 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. This rate has the potential to reduce peak demand at the generator level by 164 MW for residential customers and 90 MW for medium commercial and industrial customers under the base case scenario.[9]

Q. HOW WERE THESE CHANGES IN THE COMPANY'S CUSTOMER PRICE SIGNALS TRANSLATED TO BENEFITS IN THE AGIS AMI CBA?

A. The Company utilized the peak demand reduction assumptions from the Brattle Study to generate an estimated energy shift from peak to off-peak hours. This shift from peak to off-peak was then multiplied by the difference in the Minnesota Hub on and off-peak price forecasts filed with our Integrated Resource Plan (Docket No. E002/RP-19-368) on page 13 of Appendix F2. This estimates the savings in energy prices customers will experience in shifting their demand from on to off-peak.

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7 Brattle Study at Appendix D, p.68.
8 Brattle Study at p.6.
9 Brattle Study at Appendix D, p. 68.

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT DUE TO REDUCTIONS IN CARBON DIOXIDE EMISSIONS FOR AMI?

A. The Company utilized load shifting estimates in MWh for TOU rates from The Brattle Study. The Company estimated on-peak and off-peak average CO_2 emissions by year using internal tools. The difference in those two estimates represents the emissions improvement. This amount is multiplied by the MWh shifted due to TOU rates. The avoided carbon emission is valued by multiplying the avoided emissions by the Commission-ordered externality values from Docket No. E999/CI-14-643.

Q. HOW DOES THE BRATTLE GROUP'S FRAMEWORK COMPARE TO OTHERS FOR MEASURING LOAD FLEXIBILITY?

A. As noted by Brattle on page ii of the Study, its modelling framework "builds upon the standard approach to quantifying [demand response] potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs." The Brattle Group then goes on to identify those differentiating features, each of which is intended to enhance the reliability and sophistication of the analysis. The Company therefore relied upon the Brattle Study to assume that a consistent reduction in peak demand would be reasonable and achievable as a function of the demand rates AMI will enable as part of the Company's proposal. This reduction is then incorporated into the CBA as a benefit of AMI.

Q. WHAT ASSUMPTIONS ARE MADE WITH RESPECT TO CUSTOMER ADOPTION OF THESE NEW TECHNOLOGIES?

A. As discussed in more detail by Company witness Mr. Cardenas, we propose an opt-out approach to AMI metering, meaning that customers will be automatically integrated into the new system unless they actively opt out. In addition, the opt-out deployment approach tends to result in overall higher enrollment rates than when utilities adopt an opt-in approach to AMI, and therefore enables larger aggregate demand impacts via the more advanced rate structures AMI enables. Overall, the Brattle Study notes that an opt-out approach – with the default being the customer receives AMI functionality – "maximizes the overall economic benefit of the program."[10] The Brattle Group modeled this opt-out approach as the default rate offering.

Q. WHAT IS THE IMPACT OF THESE OPT-OUT ASSUMPTIONS ON THE CBA?

A. There is no direct net cost impact because, as Mr. Cardenas explains, we propose to have those customers who opt out pay for the cost of a new meter capable of storing data needed for future rate designs. In addition, customers who opt out would incur a monthly charge to cover the cost of meter reading. Because these charges would be established in an amount that directly offsets the costs of opting out, there is no direct material net cost impact to the CBA. However, the opt-out approach does improve the benefit as described above.

2. FLISR Inputs

Q. WHAT IS THE FLISR PROGRAM?

A. The Fault Location Isolation and Service Restoration (FLISR) component of the AGIS initiative is a synchronized system of devices that can reduce the

[10] Brattle Study at p. 31.

number of customers impacted by a fault via automatically isolating the trouble area and restoring service to remaining customers by transferring them to adjacent circuits. The fault isolation feature of the technology can help crews locate the trouble spots more quickly, resulting in shorter outage durations for the customers impacted by the faulted section. In short, the purpose of FLISR is to reduce the duration and impact of outages on our customers. Company witness Ms. Bloch discusses the purpose of FLISR in more detail.

Q. WHAT ARE THE COSTS OF FLISR?

A. The majority of the FLISR costs are the asset/device costs, as well as the labor cost of installation. Other costs include the supporting FAN components and IT resources. As previously noted, FLISR costs also include contingency amounts.

Q. HOW WERE FLISR COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the FLISR program (including contingencies) are detailed in the Direct Testimony of Company witnesses Ms. Bloch and Mr. Harkness, as set forth in Tables 6 through 8 below. FLISR's quantifiable benefits relate primarily to Customer Minutes Out (CMO) measures of reduced customers' outage duration; therefore, the benefits of FLISR are not directly O&M or capital-related. My Exhibit___(RD-1), Schedule 3 provides a summary of each component of the quantifiable FLISR costs and benefits, as they appear in the CBA.

Q. WHAT ARE THE CAPITAL COSTS AND BENEFITS OF FLISR?

A. A summary of capital costs is set forth in Table 7, below.

Table 7

Capital Costs of FLISR

Capital Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	Capital costs of the FLISR devices and installation, including both internal and external support	Direct Testimony of Ms. Bloch, Section V(F)(6)
Field Area Network (FLISR)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of FLISR.	Direct Testimony of Mr. Harkness, Section V(E)(5)(b)

Q. HOW WERE FLISR O&M INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. FLISR O&M costs and benefits were developed by Ms. Bloch and Mr. Harkness as set forth below:

Table 8

FLISR O&M Costs

O&M Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	O&M costs of the FLISR devices and installation.	Direct Testimony of Ms. Bloch, Section V(F)(6)
Field Area Network (FLISR)	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of FLISR.	Direct Testimony of Mr. Harkness, Section V(E)(5)(b)

Table 9

Other Quantifiable FLISR Benefits

Benefits	**Description**	**Supporting Witness (including Section of Testimony)**
Customer Minutes Outage – Savings	Benefits to customers associated with reduced outage duration	Direct Testimony of Ms. Bloch, Section V(F)(5)
Outage Patrol Time Savings	Benefit associated with reduction in time spent by field crews responding to outages	Direct Testimony of Ms. Bloch, Section V(F)(5)

3. IVVO Inputs

Q. WHAT IS INTEGRATED VOLT-VAR OPTIMIZATION?

A. Generally speaking, IVVO is a leading technology that automates and optimizes the operation of distribution voltage regulating devices and VAr control devices to maximize system efficiency. As described in more detail in the Direct Testimony of Ms. Bloch, through the implementation of IVVO the Company will be able to control the voltage on a distribution feeder to a tighter tolerance, permitting the Company to lower the voltage on that controlled feeder while still maintaining a high level of service quality. This lower voltage will effectuate energy and demand savings for the system and for the customer.

Q. WHAT ARE THE PRIMARY COSTS AND BENEFITS OF IVVO?

A. The primary costs of implementing IVVO relate to installation of application assets as well as the labor cost of installation. Other costs include FAN communications, IT systems and integration, and program management. The benefits of IVVO that were quantified in the CBA are the fuel and energy savings and capacity savings associated with the program, which are described by Ms. Bloch, and the associated carbon reduction that I describe. The costs of IVVO also include contingency amounts, which are supported by Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack.

Q. HOW WERE IVVO CAPITAL INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost estimates for the IVVO program (including contingencies) are detailed in the Direct Testimony of Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack, as set forth in Tables 10 through 13 below. My Exhibit___(RD-1), Schedule 4 provides a summary of each component of the quantifiable IVVO costs and benefits, as they appear in the CBA.

Q. WHAT ARE THE CAPITAL COSTS AND BENEFITS OF IVVO?

A. A summary of capital costs and benefits is set forth in Table 10 and 11, below.

Table 10

IVVO Capital Costs

Capital Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	Capital costs of the IVVO devices and installation. Capital costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(G)(5)
Field Area Network (IVVO)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of IVVO.	Direct Testimony of Mr. Harkness, Section V(E)(6)(b)
Program Management	Capital costs associated with internal management of IVVO.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 11

IVVO Capital Benefits

Capital Benefits	**Description**	**Supporting Witness (including Section of Testimony)**
Avoided Capacity Costs	Avoided generation, transmission and distribution capacity achieved through demand reduction	Direct Testimony Ms. Bloch, Section V(G)(4)

Q. HOW WERE IVVO O&M AND OTHER INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. IVVO O&M costs and Other benefits were developed as set forth below:

Table 12

IVVO O&M Costs

O&M Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	O&M costs of the IVVO devices and installation.	Direct Testimony of Ms. Bloch, Section V(G)(5)
Field Area Network (IVVO)	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of IVVO.	Direct Testimony of Mr. Harkness, Section V(E)(6)(b)
Program Management	O&M costs associated with internal management of IVVO.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 13

Other Quantifiable IVVO Benefits

Other Benefits	**Description**	**Supporting Witness (including Section of Testimony)**
Fuel Savings (Energy Reduction)	Fuel cost savings associated with avoided energy usage	Direct Testimony of Ms. Bloch, Section V(G)(4)
Fuel Savings (Energy Reduction)	Fuel cost savings associated with reduction in line losses	Direct Testimony of Ms. Bloch, Section V(G)(4)
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to load reduction.	My Direct Testimony, below

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT DUE TO REDUCTIONS IN CARBON DIOXIDE EMISSIONS FOR IVVO?

A. As described by Company witness Ms. Bloch, the Company estimated the energy savings associated with the IVVO program. This reduction in energy usage was converted to avoided CO_2 emissions based on projected CO_2 intensity per MWh. We then calculated the societal benefit of these avoided CO_2 emissions using the Commission-ordered externality values from its

January 3, 2018, Order Updating Environmental Cost Values in Docket No. E999/CI-14-643.

Q. ARE THERE ANY UNIQUE ASPECTS OF IVVO FOR CBA PURPOSES, AS COMPARED TO THE OTHER COMPONENTS OF AGIS?

A. Yes. As Ms. Bloch describes in more detail, IVVO benefits depend on assumptions about the level of energy and demand savings that can be achieved on NSPM's specific system. She explains that while the Company feels confident that 1 percent average energy savings and 0.6 percent capacity savings are the most readily achievable levels, the Company also identified 1.5 percent energy savings and 0.8 percent capacity savings as the higher end of the achievable range. For purposes of the CBA, we utilized the mid-point of the range (1.25 percent energy savings and 0.7 percent capacity savings), and also present as sensitivities that utilize the lower (1.0 percent energy/0.6 percent capacity savings) and upper (1.5 energy/0.8 percent capacity savings) ends of the identified range. Below I provide the resulting benefit-to-cost ratios with and without contingency.

Q. OVERALL, HOW WOULD YOU CHARACTERIZE THE COST AND BENEFIT BUDGETING ASSUMPTIONS IN THIS MODEL FOR EACH OF THE COMPONENTS OF THE AGIS INITIATIVE?

A. Particularly for the modeling results that include 100 percent of the Company's planned contingencies, I would characterize this model as a conservative representation of estimated costs and benefits. Because AMI, FLISR, and IVVO are still in their early phases, the contingencies represent early estimates of potential additional costs. Likewise, the Company has estimated customer adoption and response on the basis of the Brattle Study;

as technologies continue to improve, the benefits associated with these technologies may also increase. Our goal is to represent a conservative but realistic analysis to support the Commission's review of our cost benefit model for the AGIS initiative.

C. CBA Results

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE AMI PROGRAM.

A. Table 14 summarizes the results of the Company's evaluation of AMI, both with and without contingency.

Table 14
AMI Benefit-to-Cost Ratio

NSPM-AMI-NPV	**Total ($MM)**
Benefits	446
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	(538)
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**
Benefit/Cost Ratio (no contingencies)	**0.99**

Exhibit___(RD-1), Schedule 3 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of AMI, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF AMI?

A. On a total resource benefit-to-cost ratio basis, AMI is expected to have a benefit-to-cost ratio of approximately 0.83-0.99, which indicates that the costs somewhat exceed quantitative benefits over the analysis period.

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE FLISR PROGRAM.

A. Table 15 summarizes the results of the Company's evaluation of FLISR:

Table 15

FLISR Benefit-to-Cost Ratio

NSPM FLISR- NPV	**Total ($MM)**
Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**
Benefit/Cost Ratio (no contingencies)	**1.53**

Exhibit___(RD-1), Schedule 3 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of FLISR, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF THE FLISR PROGRAM, INCLUDING THE FAN COMPONENT?

A. On a total resource benefit-to-cost ratio basis, FLISR benefits are expected to exceed FLISR cost, with an expected benefit-to-cost ratio of approximately 1.31 to 1.53.

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE IVVO PROGRAM.

A. Table 16 summarizes the results of the Company's evaluation of IVVO, showing sensitivities for contingency ranges and levels of capital/O&M savings assumptions.

Table 16

IVVO Benefit to Cost Ratio

NSPM IVVO- NPV	**Total ($MM)**
Benefits	**22**
Other Benefits	19
CAP Benefits	3
Costs	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (CVR 1.25% energy; 0.7% capacity)	**0.57**
Benefit/Cost Ratio (no contingencies)	**0.61**
Low Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1% energy; 0.6% capacity)	0.46
Benefit/Cost Ratio (no contingencies)	0.49
High Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1.5% energy; 0.8% capacity)	0.67
Benefit/Cost Ratio (no contingencies)	0.72

Exhibit___(RD-1), Schedule 4 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of IVVO, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF THE IVVO PROGRAM, INCLUDING THE FAN COMPONENT?

A. On a total resource benefit-to-cost ratio basis, IVVO costs are expected to exceed quantifiable IVVO benefits, with an expected benefit-to-cost ratio of 0.57 to 0.61, within a range of sensitivities between 0.46 to 0.72.

Q. DO YOU ALSO PROVIDE A COMBINED SUMMARY OF THE COSTS AND QUANTITATIVE BENEFITS OF THE PROGRAMS?

A. Yes. To determine the combined cost benefit ratio for the AGIS initiative, we identified and aggregated the benefits of each project into four different categories: O&M, Capital, Customer, and Other benefits. At the same time, we aggregated the two types of costs of each project: O&M and Capital/ Change in Revenue Requirements. The final combined ratio is the result of dividing the aggregated benefits by the aggregated costs. Table 17 summarizes the results of the Company's evaluation of the combined AMI/FLISR/IVVO program:

Table 17

AGIS Initiative Combined Cost Benefit Ratio

NSPM -AMI, FLISR, IVVO-NPV	**Total ($MM)**
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
Capital Benefits	193
Costs	**(656)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Baseline Benefit-Cost Ratio (IVVO 1.25% energy, 0.7% capacity, with contingencies)	**0.87**
High Benefit/No Contingency Sensitivity (IVVO 1.5% energy/0.8% capacity, no contingency)	1.03
Lower Benefit/With Contingency Sensitivity (IVVO 1.0% energy/0.6% capacity, with contingencies)	0.86

Exhibit___(RD-1), Schedule 7 to my Direct Testimony provides the overall relative costs and benefits of the AGIS initiative.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL QUANTITATIVE OUTCOMES OF THE AGIS CBA?

A. On a combined basis, the quantifiable benefits of AMI, FLISR, and IVVO are expected to be lower than or in line with program costs, with an expected benefit-to-cost ratio of approximately 0.86 under our low scenario and up to 1.03 with our high sensitivity IVVO benefits and no contingencies. These totals represent a simple combination of AMI, FLISR, and IVVO respective costs and benefits, inclusive of the costs attributable to that portion of the FAN needed to enable AMI, FLISR, and IVVO, presented on a NPV basis.

In the next section of my Direct Testimony, I address other cost/benefit considerations that factor into the overall prudence of the Company's proposed AGIS initiative.

III. LEAST-COST/BEST-FIT ALTERNATIVES

Q. DID THE COMPANY ALSO DEVELOP ANY LEAST-COST/BEST-FIT ANALYSES TO COMPARE METERING ALTERNATIVES?

A. Yes. While Company witness Ms. Bloch also provides extensive discussion regarding the relative costs and benefits of various meter-reading alternatives, my Table 18 summarizes the results of the Company's evaluation. The aggregated benefits and capabilities provided by the AMI system related to its costs definitely surpasses other options, considering the increasing needs and choices demanded by the customers and the upcoming operational distribution-grid challenges. This assessment essentially summarizes the bases for our selection of the AMI solution we are presenting in this case.

Table 18

Meter Reading Least-Cost Best-Fit Alternative

Item	Description	Alternative: Manual	Alternative: AMR 1 way/ Limited 2 way	Alternative: AMR Drive-By	Alternative: AMI
Meter Capabilities	Time of use data	◔	◑	◔	●
	Real time notification of power outages	○	◑	○	●
	Fast response to customers inquires	○	◔	○	●
	Support integrated systems that offer customers	○	◔	○	●
	Vehicle to grid interconnects	○	○	○	●
	Remote reconfiguration/ firmware updates	○	○	○	●
	Availability of real time data	○	○	○	●
	Availability of power quality events	○	○	○	●
	Remove availability of meter diagnostic data	◔	◔	◔	●
	Remote disconnect/ connect	○	○	○	●
	Detect unsafe field metering conditions	○	○	○	●
	Energy Theft	◔	◔	◔	●
	Support for advanced rates	○	○	○	●
	Support for ADMS	○	○	○	●
Operational Features	Time consuming activity	A	NA	NA	NA
	Labor intensive - Safety Concerns	A	NA	PA	NA
	Cost of paying someone to read the meters.	A	NA	PA	NA
	Need access to meters to read them.	A	NA	NA	NA
	Accuracy of the meter read, human error.	A	NA	NA	NA
	Usually carried out infrequently (monthly).	A	PA	PA	NA
	Doesn't usually match invoice billing period.	A	PA	PA	NA
	Cost of system maintenance	NA	A	A	A
	Relying on technology	NA	A	A	A
NPV (2019)	Calculated COSTS - CAP Change in RR and O&M			$223M	$539M
	BENEFITS-Incremental to current reading/ billing			$0M	$442M
	NET COST-OUTCOME			**$223M**	**$97M**
	Least-Cost, Best-Fit Alternative Selected				**AMI System**

Legend for Capabilities

Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

Legend for Operational Features

Applicable	Partially Applicable	Non-Applicable
A	PA	NA

Q. HOW DID YOU CALCULATE THE COSTS AND BENEFITS OF THE AMR AND AMI SOLUTIONS FOR PURPOSES OF THIS LEAST-COST/BEST-FIT ANALYSIS?

A. The AMR Drive-by cost and benefit assessments were provided by Company witness Ms. Bloch, and are discussed in her Direct Testimony. The total cost of this system results from the incremental capital and O&M necessary to implement an AMR drive-by solution as a replacement for our current meters. However, this system does not provide any incremental benefit to the current Cellnet meter/billing structure. The costs and benefits of the AMI system were provided by Ms. Bloch, Mr. Harkness, and Mr. Cardenas, as described earlier in my testimony. In contrast, we did not calculate the cost of manual or AMR limited two-way alternatives because we did not consider these realistic solutions given the state of the industry and the needs of our system, customers, and other stakeholders. Table 18 above underscores why we are proposing an AMI solution.

Q. DID YOU COMPLETE A SIMILAR ASSESSMENT WITH RESPECT TO THE COMMUNICATIONS NETWORK NECESSARY TO SUPPORT THE AGIS INITIATIVE?

A. Yes. Company witness Mr. Harkness provides an extensive discussion relative to the costs and benefits of the three communication network alternatives the Company considered. My Table 19 summarizes the results of the Company's evaluation of the aggregated capabilities and protections provided by the FAN with a mesh network, compared to other alternatives.

Table 19

Communications Least-Cost Best-Fit Alternative

Item	Feature/ Requirement	Alternative: Cellular	Alternative: Dedicated AMI	Alternative: FAN Mesh
Network Capabilities	Two way communications	●	●	●
	Peer-to-Peer	◔	◕	●
	Multipurpose	◕	◔	●
	Latency Requirements	●	◕	●
	Security	◑	●	●
	Dedicated traffic	◔	◕	●
	Priority traffic	◔	●	●
	O&M Costs Impact (run state)	◔	◑	●
	Resiliency	◑	◑	●
Operational Features	Cost of paying a third party for service	A	NA	NA
	Unable to fully control the system "end-start"	A	NA	NA
	Unable to implement to some AGIS processes	NA	PA	NA
	Relying on technology	A	A	A
NPV (2019)	Calculated COSTS - CAP Change in RR and O&M			$102M
	BENEFITS-Incremental to current reading/ billing			$0M
	NET COST-OUTCOME			**$102M**
	Least-Cost, Best-Fit Alternative Selected			**FAN Mesh**

Legend for Capabilities

Full	Most	Partial	Minimal	None
●	?	?	?	○

Legend for Operational Features

Applicable	Partially Applicable	Non-Applicable
A	PA	NA

Q. HOW DID YOU CALCULATE THE COSTS OF THE COMMUNICATION NETWORK ALTERNATIVES IN THE LEAST-COST/BEST-FIT ANALYSIS?

A. The cost of the FAN components and deployment were provided by Company witness Mr. Harkness, and are described in his testimony. Additionally, Mr. Harkness explains that in comparing alternatives to the FAN, the Company determined that a cellular option would likely have a similar device cost with additional O&M costs; therefore, the cost is expected to be at best equal to and more likely higher than FAN costs. Furthermore, Mr. Harkness explains that a dedicated AMI network was ruled out because it would not allow non-AMI devices to connect to each other or to back office applications, affecting overall system functionality. As such, Table 19 does not show specific cost vs. benefit estimates for alternatives to the FAN, but rather focuses on the relative capabilities of all three alternatives.

Q. DID THE COMPANY COMPLETE A LEAST-COST/BEST-FIT ANALYSIS FOR IVVO OR FLISR?

A. No; it would not have made sense for these components of the AGIS initiative. IVVO and FLISR are, more simply, additional ADMS capabilities. In contrast, there are different fundamental types of meter solutions and communication networks. While there are forms of IVVO and FLISR devices that have different individual capabilities, such comparisons were conducted in the RFP processes, as discussed by Ms. Bloch.

Q. WHAT DO THESE LEAST-COST/BEST-FIT ANALYSES SHOW?

A. They provide another means (in addition to the CBA and the extensive narrative testimony) of comparing the AGIS solutions with alternatives. They largely summarize the analyses Ms. Bloch, and Mr. Harkness provide in much greater detail, and underscore why it was prudent to select AMI and the FAN.

IV. QUALITATIVE BENEFITS OF AGIS

Q. ARE THERE SPECIFICALLY IDENTIFIABLE BENEFITS THE AMI PROGRAM WILL PROVIDE TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. There are a number of benefits of AMI that cannot be quantified either in whole or in part. For example, it is difficult to quantify customers' need and broad expectation to have more choice in and control over their energy usage, or their frustration with older technologies that cannot be updated without better data access. Our analysis captures estimates of customer adoption of technologies to support customer choice and the impacts on energy usage, but cannot fully quantify customer satisfaction associated with having better energy usage and pricing information. Nor can it fully quantify the convenience to customers of better outage management.

The unquantifiable benefits, or benefit the Company did not model in the CBA, are largely discussed by Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack. These include but are not limited to:

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

Q. ARE THERE ANY BENEFITS THAT THE FLISR PROGRAM PROVIDES TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. As with AMI, there are benefits of FLISR that the Company did not attempt to quantify. It is important to note that FLISR does not avoid outages altogether, but works to minimize their impacts on customers when they do occur, improving the customer's experience and leading to customer satisfaction. Thus the qualitative benefits include but are not limited to:

- Improved public and employee safety,
- Value of the data provided by FLISR for system planning purposes, and
- Overall customer satisfaction with utility service.

Q. ARE THERE ANY BENEFITS THAT THE IVVO PROGRAM PROVIDES TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. As with AMI and FLISR, there are benefits of IVVO that the Company did not attempt to quantify. They include but are not limited to:

- Customer bill savings specific to customers whose feeders are equipped with IVVO assets;
- Enhanced automatic access of low income customers to energy efficiency savings;
- Greater efficiencies from the customers' personal electrical devices; and
- Increased hosting capacity of distributed energy resources.

Q. CAN YOU PROVIDE MORE DETAIL REGARDING THESE QUALITATIVE BENEFITS OF IVVO?

A. Yes. With respect to low income customers' access to energy efficiency savings, I note that Ms. Bloch explains how IVVO can reduce voltage, and therefore save customers money without requiring any change in energy usage or activities on the customers' part. Additionally, IVVO is not tied to any particular energy efficiency program, so it has the added benefit of saving money for customers – including low income customers – who are sometimes unable to take advantage of such programs.

Q. WHY DIDN'T THE COMPANY ATTEMPT TO QUANTIFY THESE BENEFITS?

A. Although the Company feels strongly that these benefits are meaningful to our customers, it is difficult and often highly subjective to attempt to place a dollar value on them. For example, customer satisfaction and empowerment are important to the Company's business model and role as a public utility, but do not easily lend themselves to monetization.

The Company therefore concluded that it was best to provide a cost and benefit analysis to the Commission that fairly represents the cost and benefits of quantifiable projects components, and which we were able to value with reasonable confidence, and then ask the Commission to weigh the other impacts to our customers as it sees fit. In this way, the Commission may rely on the CBA as a baseline of our business case for our projects, and then evaluate and discuss the merits of the additional beneficial impacts to our customers.

Q. WHY SHOULD THE COMMISSION CONSIDER APPROVING COST RECOVERY FOR AMI, FLISR, AND IVVO IF COMBINED PROGRAM COSTS EXCEED THE OVERALL QUANTITATIVE BENEFITS?

A. There are several reasons why AMI, FLISR, and IVVO are overall valuable resources, even if costs slightly exceed estimated quantifiable benefits.

First, the Company AMI, FLISR, and IVVO implementation will allow the Company to achieve greater visibility into its distribution system, greater opportunities for demand side management, and improved reliability. Conversely, we cannot make the same progress in these areas without enhancing the distribution grid. As Mr. Gersack discusses, these are also necessary components of any new rate structures or other initiatives the Commission may wish to implement; right now, the Company simply does not have the technical capability or insight into customer usage to implement such technologies or customer support without AMI, FLISR, and IVVO.

Second, I would not necessarily expect quantifiable benefits to exceed costs, particularly for AMI, because it is necessary to replace aging technology. On the one hand, the Company's current meters will no longer be considered current technology nor supported as the Cellnet contract comes to an end, but on the other hand a CBA does not take into account that we cannot function without metering. Further, the model cannot fully reflect that AMR meters are an outdated option that will not provide the functionality customers, stakeholders, and the Commission have come to expect, nor the system support necessary in the age of DER.

Third, this model is not the only manner in which we measure the value of the grid advancement options available to us. Much of the Company's comparison of alternative options is completed in the Request for Information (RFI) and Request for Proposal (RFP) proceedings, rather than in a CBA based on our final selections. As described by Ms. Bloch, we have made careful and prudent AMI selections and negotiated a strong contract with our new AMI vendor. Ms. Bloch also discusses alternative considerations and vendor options for other system devices. Likewise, the FAN communications network is the product of robust RFP processes discussed by Mr. Harkness.

Given this prudent approach to selection of infrastructure, the ultimate question is whether overall costs are reasonable.

Fourth, this model can only quantify that which is quantifiable. Its expression of benefits does not include such qualitative benefits as customer choice and convenience, human safety, and potential support for future distributed energy resources. We recognize that choice, convenience, and greater control over energy costs and usage are of increasing importance to our customers. Customer satisfaction and customer empowerment with respect to their energy choices are of central importance to the public utility model.

Fifth and finally, the Company's AGIS witnesses describe at length why it is important to advance the NSPM grid to continue providing safe, increasingly reliable electric service to our customers not just in the present but also into the future. While we cannot predict every new technology that will arrive, we know that our current system is not future-proofed. Conversely, the AGIS program will support a fundamental utility function while improving existing infrastructure that is no longer maximizing service to our customers. It makes future applications, optionality, and distributed energy resources available in a way it is not possible to fully measure because it is not possible to fully predict the future. But as Mr. Gersack describes, utilities nationwide are making these important grid investments because "doing nothing" is not a realistic option. Therefore, the Company feels that this is both the right time and an important time to modernize critical components of its distribution grid.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's AGIS CBA is a tool that is helpful, but not sufficient, to assess the overall prudence of the AGIS strategy and investments. We believe it is realistic and appropriate that our CBA shows individual and composite benefit-to-cost ratios that approach 1.0 (or exceed 1.0 in the case of FLISR), even before taking into account unquantifiable benefits. With those qualitative considerations and benefits, the Company believes the value of the AGIS initiative and its respective components substantially exceed the costs. Finally, both the CBA itself and our least cost/best fit summative analyses underscore that our AGIS program is reasonable given the need to replace aging technology, bring our distribution grid into the future, meet customer needs and offer greater customer choice, and take advantage of opportunities to use technology to support demand side management, peak demand reductions, and build a more resilient and responsive grid.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

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Director, Risk Strategy
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Ravikrishna Duggirala has more than 25 years of diverse experience in various industries in the areas of Engineering, Operations, Business Development, and Risk Management. Dr. Duggirala joined Xcel Energy in 2002 and is currently Director of Risk Strategy, where he is responsible for Enterprise Risk Management, Asset Risk Management, risk analytics, and modeling. He has held this position since 2008. Previously, Dr. Duggirala was the Manager of Energy Sales Risk for Xcel Energy from 2005 through 2008, where he was responsible for retail sales risk analysis, key risk analysis, sensitivity analysis, and risk analytics. Dr. Duggirala was also a Risk Consultant with the Company between 2002 and 2005, where he was responsible for monitoring and reporting of trading risks, managing risk policies and procedures and supporting Corporate Risk Management Oversight Committee. Prior to working for Xcel Energy, Dr. Duggirala worked at other companies including Enron, Monsanto, and Purdue University in various capacities.

Dr. Duggirala received his Masters Degree in Business Administration from Washington University in St. Louis in 2000, and his Ph.D in Engineering from Purdue University in 1996.

Northern States Power Company
AMI Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
AMI Meters																			
AMI Meters Purchase	1,408,513	1,024,373	13,875,456	71,769,600	67,212,800	4,636,544	1,771,935	1,826,384	1,882,506	1,940,352	1,999,976	2,061,432	2,124,776	2,190,067	2,257,364	2,326,730	2,398,226	**182,707,036**	**132,855,955**
AMI Meter Installation	620,017	450,922	5,054,700	26,145,000	24,485,000	1,689,050	645,500	665,335	685,779	706,852	728,573	750,961	774,036	797,821	822,337	847,606	873,652	**66,743,140**	**48,567,278**
RTU's (Return to Utility- Estimate 3% of installed meters)	0	0	303,282	1,568,700	1,469,100	101,343	0	0	0	0	0	0	0	0	0	0	0	**3,442,425**	**2,619,423**
Vendors deployment Project Management	0	381,182	733,817	1,198,410	1,223,217	624,270	0	0	0	0	0	0	0	0	0	0	0	**4,160,897**	**3,204,164**
AMI Operations (Internal Personnel)	843,677	983,487	1,869,203	2,046,398	2,186,980	1,903,327	0	0	0	0	0	0	0	0	0	0	0	**9,833,071**	**7,716,691**
AMI Operations (External Personnel)	0	0	658,073	1,372,663	1,365,055	637,919	0	0	0	0	0	0	0	0	0	0	0	**4,033,710**	**3,053,879**
Shop & Lab equipment (AMI Field Test, Lab equip)	0	25,888	217,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**243,288**	**203,171**
Distribution Contingencies	442,320	441,341	3,497,637	16,031,519	15,083,091	1,477,238	0	0	0	0	0	0	0	0	0	0	0	**36,973,146**	**28,259,602**
TOTAL - AMI Meters	3,314,527	3,307,193	26,209,569	120,132,290	113,025,244	11,069,690	2,417,435	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***308,136,713***	***226,480,162***
Communications Network																			
FAN Infrastructure Distribution	100,005	650,501	1,279,994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,030,499**	**1,729,867**
FAN Distribution WiMax	322,537	2,097,993	4,128,233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,548,763**	**5,579,166**
FAN Bus Sys Costs	1,709	51,120	88,387	59,329	56,142	15,200	0	0	0	0	0	0	0	0	0	0	0	**271,887**	**217,842**
FAN Bus Sys WiMAX Cost	334,633	10,011,076	17,309,267	11,618,600	10,994,506	2,976,466	0	0	0	0	0	0	0	0	0	0	0	**53,244,549**	**42,660,847**
FAN Bus Sys Contingency	73,854	1,267,037	2,253,221	1,166,606	1,103,942	298,863	0	0	0	0	0	0	0	0	0	0	0	**6,163,522**	**4,979,818**
TOTAL - Communications	***832,739***	***14,077,726***	***25,059,102***	***12,844,535***	***12,154,590***	***3,290,528***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***68,259,221***	***55,167,540***
IT Systems and Integration																			
IT Hardware	1,504,080	2,537,978	2,141,049	545,521	556,814	568,340	580,104	0	0	0	0	0	0	0	0	0	0	**8,433,885**	**7,028,256**
IT Software	1,064,115	1,552,117	5,536,877	4,669,670	323,141	0	0	0	0	0	0	0	0	0	0	0	0	**13,145,919**	**10,838,063**
IT Labor + Project Management	1,725,374	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,725,374**	**1,621,097**
IT Contingency	0	0	0	11,176,589	605,252	548,564	174,031	0	0	0	0	0	0	0	0	0	0	**12,504,436**	**9,642,915**
TOTAL - IT Systems and Integration	***4,293,568***	***4,090,095***	***7,677,926***	***16,391,780***	***1,485,207***	***1,116,904***	***754,136***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***35,809,615***	***29,130,330***
Program Management																			
Change Management	0	1,000,000	1,035,500	1,072,260	1,110,325	1,149,742	1,190,558	0	0	0	0	0	0	0	0	0	0	**6,558,386**	**4,950,734**
Environment/Release Management	0	28,071	2,064,464	2,318,348	1,044,303	355,017	99,666	0	0	0	0	0	0	0	0	0	0	**5,909,870**	**4,617,070**
Finance	0	109,959	193,798	194,658	145,467	0	0	0	0	0	0	0	0	0	0	0	0	**643,882**	**516,017**
PMO	0	288,790	506,590	508,944	381,346	0	0	0	0	0	0	0	0	0	0	0	0	**1,685,670**	**1,350,955**
Security	0	1,105,737	1,144,991	1,185,638	1,227,728	0	0	0	0	0	0	0	0	0	0	0	0	**4,664,093**	**3,748,708**
Supply Chain	0	477,703	487,591	497,685	507,987	0	0	0	0	0	0	0	0	0	0	0	0	**1,970,966**	**1,585,917**
Talent Strategy	238,852	349,325	361,726	185,901	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,135,803**	**977,689**
Delivery and Execution Leadership	0	374,158	1,294,786	1,314,010	667,319	0	0	0	0	0	0	0	0	0	0	0	0	**3,650,273**	**2,916,840**
Contingency	11,943	186,687	354,472	363,872	254,224	75,238	64,511	0	0	0	0	0	0	0	0	0	0	**1,310,947**	**1,033,197**
TOTAL - Program Management	***250,795***	***3,920,430***	***7,443,919***	***7,641,315***	***5,338,699***	***1,579,997***	***1,354,735***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***27,529,891***	***21,697,127***
TOTAL CAPITAL	**8,691,629**	**25,395,444**	**66,390,515**	**157,009,920**	**132,003,740**	**17,057,120**	**4,526,306**	**2,491,719**	**2,568,285**	**2,647,205**	**2,728,549**	**2,812,393**	**2,898,813**	**2,987,889**	**3,079,701**	**3,174,336**	**3,271,878**	***439,735,439***	***332,475,159***
O&M ITEMS																			
Communications Network																			
FAN Network Infrastructure Distribution	0	0	130,976	298,507	271,352	225,136	105,810	54,000	55,118	56,259	57,424	58,612	59,826	61,064	62,328	63,618	64,935	**1,624,966**	**1,036,835**
FAN Network Business Systems	0	0	335,766	3,171,422	2,673,589	1,491,278	499,575	671,918	685,827	700,023	714,514	729,304	744,401	759,810	775,538	791,592	807,978	**15,552,536**	**9,460,970**
FAN WiMAX Cost	233,600	357,245	427,150	434,290	562,241	1,048,049	653,607	0	0	0	0	0	0	0	0	0	0	**3,716,182**	**2,782,723**
NOC Opco Allocation	200,000	408,280	625,097	638,037	651,244	664,725	678,485	692,529	706,864	721,497	736,432	751,676	767,235	783,117	799,328	815,874	832,762	**11,473,181**	**6,445,717**
FAN Network Distribution Contingency	0	0	59,854	136,414	124,004	102,885	48,354	24,677	0	0	0	0	0	0	0	0	0	**496,189**	**363,768**
FAN Network Bus Sys Contingency	0	0	301,130	686,305	623,871	517,616	243,271	124,153	0	0	0	0	0	0	0	0	0	**2,496,348**	**1,830,131**
TOTAL - Communications	***433,600***	***765,525***	***1,879,974***	***5,364,975***	***4,906,301***	***4,049,690***	***2,229,101***	***1,567,278***	***1,447,809***	***1,477,779***	***1,508,369***	***1,539,592***	***1,571,462***	***1,603,991***	***1,637,194***	***1,671,084***	***1,705,675***	***35,359,401***	***21,920,143***
IT Systems and Integration																			
IT Hardware	42,114	1,654,282	1,678,585	1,705,324	1,740,624	1,776,655	1,813,432	1,850,970	1,889,285	1,928,393	1,968,311	2,009,055	2,050,642	2,093,091	2,136,418	2,180,642	2,225,781	**30,743,604**	**17,268,781**
IT Software	27,285	85,988	983,487	1,845,314	2,011,390	2,053,026	2,095,523	2,138,900	2,183,176	2,228,367	2,274,495	2,321,577	2,369,633	2,418,685	2,468,752	2,519,855	2,572,016	**32,597,467**	**17,432,600**
IT Labor	0	2,056,405	1,553,273	1,750,246	1,680,090	1,717,226	1,721,011	1,789,073	1,859,799	1,933,290	2,009,656	2,089,007	2,171,461	2,257,136	2,346,156	2,438,653	2,534,759	**31,907,241**	**17,784,018**
Common Corporate Business System development-Allocation	646,904	4,270,861	5,304,505	11,866,886	12,378,199	10,847,247	10,347,121	0	0	0	0	0	0	0	0	0	0	**55,661,724**	**41,239,207**
IT Contingency	0	997,287	9,826,939	4,112,864	2,099,639	2,145,629	2,192,624	2,240,646	2,289,716	2,339,857	2,391,093	2,443,448	2,496,946	2,551,611	2,607,470	2,664,547	2,722,871	**46,123,186**	**28,075,602**
TOTAL - IT Systems and Integration	***716,303***	***9,064,823***	***19,346,789***	***21,280,633***	***19,909,942***	***18,539,783***	***18,169,711***	***8,019,589***	***8,221,975***	***8,429,907***	***8,643,555***	***8,863,087***	***9,088,683***	***9,320,523***	***9,558,795***	***9,803,697***	***10,055,427***	***197,033,221***	***121,800,207***
Program Management																			
Change Management	0	1,825,114	2,157,971	3,067,323	3,176,213	2,991,329	1,608,666	0	0	0	0	0	0	0	0	0	0	**14,826,616**	**11,214,681**
Environment/Release Management	0	0	22,405	23,200	24,024	24,877	11,794	0	0	0	0	0	0	0	0	0	0	**106,300**	**78,991**
Finance	0	32,456	112,027	167,045	216,218	0	0	0	0	0	0	0	0	0	0	0	0	**527,746**	**410,061**
PMO	0	79,772	275,346	410,574	531,437	0	0	0	0	0	0	0	0	0	0	0	0	**1,297,129**	**1,007,876**
Talent Strategy	37,760	58,651	60,733	0	55,000	0	0	0	0	0	0	0	0	0	0	0	0	**212,144**	**177,898**
Delivery and Execution Leadership	0	217,284	510,624	714,661	897,539	0	0	0	0	0	0	0	0	0	0	0	0	**2,340,109**	**1,829,448**
Contingency	1,888	110,664	156,955	219,140	245,022	150,810	81,023	0	0	0	0	0	0	0	0	0	0	**965,502**	**735,948**
TOTAL - Program Management	***39,648***	***2,323,940***	***3,296,060***	***4,601,944***	***5,145,453***	***3,167,016***	***1,701,483***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***20,275,545***	***15,454,901***
AMI Operations (Personnel)																			
AMI Operations (Internal Personnel)	0	2,029	36,563	40,759	42,206	43,704	47,708	1,040,317	1,077,248	1,115,491	1,155,090	1,196,096	1,238,558	1,282,526	1,328,056	1,375,202	1,424,022	**12,445,575**	**5,756,644**
AMI Operations (External Personnel)	0	187,968	214,121	468,050	1,576,002	1,300,659	1,409,575	1,475,931	1,545,439	1,600,302	1,657,112	1,715,940	1,776,856	1,839,934	1,905,252	1,972,888	2,042,926	**22,688,954**	**11,693,307**
Customer Claims	0	663	1,719	48,916	48,843	7,423	0	0	0	0	0	0	0	0	0	0	0	**107,565**	**81,001**
Total AMI- O&M Dist Contingency	0	29,259	38,605	78,357	249,204	207,032	224,422	387,502	403,894	418,232	433,079	448,454	464,374	480,859	497,929	515,606	533,910	**5,410,717**	**2,687,292**
TOTAL - AMI Operations	0	219,920	291,008	636,082	1,916,255	1,558,818	1,681,704	2,903,750	3,026,581	3,134,024	3,245,282	3,360,490	3,479,787	3,603,319	3,731,237	3,863,696	4,000,857	***40,652,811***	***20,218,244***
TOTAL O&M	**1,189,551**	**12,374,208**	**24,813,831**	**31,883,634**	**31,877,951**	**27,315,307**	**23,782,000**	**12,490,618**	**12,696,365**	**13,041,711**	**13,397,206**	**13,763,169**	**14,139,931**	**14,527,833**	**14,927,226**	**15,338,477**	**15,761,959**	**293,320,977**	**179,393,496**
GRAND TOTAL CAPITAL & O&M	**9,881,180**	**37,769,652**	**91,204,347**	**188,893,554**	**163,881,691**	**44,372,427**	**28,308,306**	**14,982,337**	**15,264,650**	**15,688,915**	**16,125,755**	**16,575,562**	**17,038,744**	**17,515,722**	**18,006,927**	**18,512,812**	**19,033,837**	**733,056,417**	**511,868,655**

Northern States Power Company
AMI Cost Benefit Analysis

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Avoided O&M Meter Reading Costs																			
Drive-by Meter Reading Cost - O&M	2,155	86,393	1,085,789	2,460,063	3,740,671	3,587,859	4,153,792	4,287,938	4,426,475	4,562,493	4,702,691	4,847,197	4,996,143	5,149,667	5,307,907	5,471,011	5,639,126	**64,507,370**	**33,455,306**
TOTAL - Reduction in Meter Reading Costs	*2,155*	*86,393*	*1,085,789*	*2,460,063*	*3,740,671*	*3,587,859*	*4,153,792*	*4,287,938*	*4,426,475*	*4,562,493*	*4,702,691*	*4,847,197*	*4,996,143*	*5,149,667*	*5,307,907*	*5,471,011*	*5,639,126*	*64,507,370*	*33,455,306*
Reduction in Field and Meter Services																			
Costs savings from remote disconnect capability	0	0	0	0	386,423	1,108,454	1,592,346	1,814,095	1,878,495	2,060,451	2,133,597	2,209,340	2,287,771	2,368,987	2,453,086	2,540,171	2,630,347	**25,463,562**	**12,291,603**
Reduction in trips due to Customer equipment damage	0	0	0	0	32,617	67,549	139,894	144,860	150,003	155,328	160,842	166,552	172,465	178,587	184,927	191,492	198,290	**1,943,406**	**940,688**
Reduction in "OK on Arrival" Outage Field Trips	0	0	0	0	135,529	280,680	581,288	601,924	623,292	645,419	668,331	692,057	716,625	742,065	768,408	795,687	823,934	**8,075,238**	**3,908,746**
Reduction in Field Trips for Voltage Investigations	0	0	0	0	74,833	154,978	320,960	332,354	344,152	356,370	369,021	382,121	395,686	409,733	424,279	439,341	454,937	**4,458,764**	**2,158,225**
TOTAL - Reduction in Field & Meter Services	*0*	*0*	*0*	*0*	*629,401*	*1,611,661*	*2,634,487*	*2,893,232*	*2,995,942*	*3,217,567*	*3,331,791*	*3,450,070*	*3,572,547*	*3,699,373*	*3,830,700*	*3,966,690*	*4,107,508*	*39,940,969*	*19,299,262*
Improved Distribution System Spend Efficiency																			
Efficiency gains reliability, asset health and capacity projects- O&M	0	0	0	0	1,159	2,401	4,972	5,148	5,331	5,520	5,716	5,919	6,129	6,347	6,572	6,805	7,047	**69,067**	**33,431**
TOTAL - Improved Distribution System Spend Efficiency	*0*	*0*	*0*	*0*	*1,159*	*2,401*	*4,972*	*5,148*	*5,331*	*5,520*	*5,716*	*5,919*	*6,129*	*6,347*	*6,572*	*6,805*	*7,047*	*69,067*	*33,431*
Outage Management Efficiency																			
Outage Management Efficiency (Storm spend O&M)	0	0	0	0	604	1,250	2,589	2,681	2,776	2,875	2,977	3,082	3,192	3,305	3,422	3,544	3,670	**35,965**	**17,409**
TOTAL - Outage Management Efficiency	*0*	*0*	*0*	*0*	*604*	*1,250*	*2,589*	*2,681*	*2,776*	*2,875*	*2,977*	*3,082*	*3,192*	*3,305*	*3,422*	*3,544*	*3,670*	35,965	17,409
TOTAL O&M BENEFITS	2,155	86,393	1,085,789	2,460,063	4,371,835	5,203,171	6,795,840	7,189,000	7,430,524	7,788,455	8,043,175	8,306,268	8,578,011	8,858,691	9,148,602	9,448,050	9,757,350	104,553,371	52,805,408
OTHER BENEFITS																			
Cost reductions																			
Reduced Consumption on Inactive Meters	0	0	0	0	350,052	714,596	1,458,776	1,488,973	1,519,795	1,551,255	1,583,366	1,616,141	1,649,595	1,683,742	1,718,595	1,754,170	1,790,482	**18,879,538**	**9,235,364**
Reduced Uncollectible / Bad Debt Expense	0	0	0	0	259,816	538,078	1,114,360	1,153,920	1,194,884	1,237,303	1,281,227	1,326,711	1,373,809	1,422,579	1,473,081	1,525,375	1,579,526	**15,480,670**	**7,493,278**
Reduced outage duration benefit	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	**21,103,587**	**10,323,309**
Theft / Tamper Detection & Reduction	0	0	0	0	847,310	1,729,700	3,531,009	3,604,101	3,678,706	3,754,855	3,832,580	3,911,915	3,992,891	4,075,544	4,159,908	4,246,018	4,333,911	**45,698,446**	**22,354,455**
TOTAL - Cost Reductions	0	0	0	0	1,848,467	3,781,151	7,734,769	7,911,371	8,092,215	8,277,408	8,467,062	8,661,292	8,860,217	9,063,955	9,272,633	9,486,379	9,705,322	***101,162,241***	***49,406,407***
Load Flexibility Benefits																			
Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	19,965,050	20,415,850	21,129,600	21,780,000	22,361,590	23,136,860	23,755,800	24,531,638	25,336,224	26,164,958	27,023,654	27,910,308	**283,511,530**	**138,479,332**
Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	1,819,116	1,975,194	2,019,888	2,037,750	2,133,144	2,262,273	2,392,520	2,517,599	2,573,992	2,725,849	2,753,107	2,780,638	**27,991,070**	**13,576,886**
Time Of Usage-TOU-Avoided CO2 Emissions	0	0	0	0	0	226,876	352,119	485,400	361,972	230,903	344,421	271,720	330,772	309,477	297,166	310,767	413,652	**3,935,245**	**1,961,868**
TOTAL - Load Flexibility Benefits	0	0	0	0	0	22,011,042	22,743,163	23,634,888	24,179,722	24,725,637	25,743,554	26,420,040	27,380,008	28,219,692	29,187,972	30,087,528	31,104,598	***315,437,845***	***154,018,085***
TOTAL OTHER BENEFITS	0	0	0	0	1,848,467	25,792,193	30,477,932	31,546,259	32,271,937	33,003,045	34,210,616	35,081,332	36,240,224	37,283,648	38,460,605	39,573,907	40,809,920	416,600,086	203,424,492
CAPITAL ITEMS																			
Capital gains and other avoided purchases																			
Efficiency gains reliability, asset health and capacity projects- CAP	0	0	0	0	189,547	386,940	789,900	806,251	822,940	839,975	857,363	875,110	893,225	911,715	930,587	949,850	969,512	**10,222,915**	**5,000,776**
Outage Management Efficiency (Storm spend CAP)	0	0	0	0	313,698	649,669	1,345,465	1,393,229	1,442,688	1,493,904	1,546,937	1,601,854	1,658,719	1,717,604	1,778,579	1,841,718	1,907,099	**18,691,164**	**9,047,289**
Avoided Meter Purchases	9,788	18,152	185,992	1,086,102	2,027,125	2,203,315	2,138,852	2,218,752	2,301,754	2,387,984	2,477,572	2,570,653	2,667,369	2,767,866	2,872,297	2,980,823	3,093,609	**34,008,006**	**17,455,428**
TOTAL - Efficiency gains and other avoided CAP purchases	9,788	18,152	185,992	1,086,102	2,530,369	3,239,924	4,274,216	4,418,231	4,567,383	4,721,863	4,881,872	5,047,617	5,219,313	5,397,185	5,581,464	5,772,392	5,970,221	***62,922,085***	***31,503,493***
Avoided Meter Reading CAP investment																			
Drive-by Meter Reading Cost - CAP	20,755	412,501	3,935,923	12,881,148	23,340,750	29,130,716	29,698,551	28,887,914	28,107,557	27,361,868	26,557,430	25,715,024	24,868,419	23,999,536	23,212,398	22,384,139	21,406,031	**351,920,659**	**189,681,697**
TOTAL - Avoided Meter Reading CAP Investment	*20,755*	*412,501*	*3,935,923*	*12,881,148*	*23,340,750*	*29,130,716*	*29,698,551*	*28,887,914*	*28,107,557*	*27,361,868*	*26,557,430*	*25,715,024*	*24,868,419*	*23,999,536*	*23,212,398*	*22,384,139*	*21,406,031*	*351,920,659*	*189,681,697*
TOTAL CAPITAL BENEFITS	30,543	430,653	4,121,915	13,967,250	25,871,119	32,370,640	33,972,767	33,306,145	32,674,940	32,083,731	31,439,303	30,762,641	30,087,732	29,396,720	28,793,861	28,156,530	27,376,252	414,842,744	221,185,190
GRAND TOTAL BENEFITS	32,698	517,046	5,207,705	16,427,313	32,091,421	63,366,004	71,246,539	72,041,404	72,377,400	72,875,232	73,693,094	74,150,241	74,905,968	75,539,059	76,403,069	77,178,487	77,943,522	935,996,201	477,415,090

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

RATIO SENSITIVITY	VALUE
FAN(80% WiMAx)+ Contingencies	0.83
FAN(80% WiMAx) NO Contingencies	0.99

Northern States Power Company
FLISR Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Category
CAPITAL ITEMS - SUMMARY																							
FLISR Assets																							
Asset Cost	0	2,456,519	6,604,776	3,745,275	5,606,776	5,852,901	4,447,353	4,539,413	4,633,379	4,729,290	0	0	0	0	0	0	0	0	0	0	**42,615,682**	**29,507,829**	**Direct and Tangible**
Asset Installation	0	661,457	1,804,228	1,037,932	1,576,342	1,669,400	1,286,894	1,332,579	1,379,886	1,428,872	0	0	0	0	0	0	0	0	0	0	**12,177,590**	**8,386,388**	**Direct and Tangible**
Device related Vendor Project Management + Other Labor	0	15,533	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,533**	**13,712**	**Direct and Tangible**
Asset Contingency	0	0	0	1,499,386	1,866,899	919,536	604,982	617,505	630,288	643,334	0	0	0	0	0	0	0	0	0	0	**6,781,930**	**4,638,594**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***3,133,508***	***8,409,004***	***6,282,593***	***9,050,018***	***8,441,837***	***6,339,229***	***6,489,497***	***6,643,552***	***6,801,496***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***61,590,735***	**42,546,523**	
Communications Network																							
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Distribution WiMax	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,227,893**	**1,046,094**	**Direct and Tangible**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	62,744	1,877,077	3,245,488	2,178,488	2,061,470	558,087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,983,353**	**7,998,909**	**Direct and Tangible**
FAN Bus Sys Contingency	48,467	831,493	1,478,676	765,585	724,462	196,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**4,044,811**	**3,268,006**	**Direct and Tangible**
TOTAL - Communications	171,686	3,101,943	5,498,207	2,944,073	2,785,932	754,216	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***15,256,057***	**12,313,008**	
IT Systems and Integration																							
ADMS FLISR Integration	0	372,780	503,962	521,853	1,023,270	1,059,597	807,499	836,165	865,849	896,587	0	0	0	0	0	0	0	0	0	0	**6,887,562**	**4,636,414**	**Direct and Tangible**
IT Contingency	0	0	0	299,788	632,358	654,807	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,586,953**	**1,147,107**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***372,780***	***503,962***	***821,641***	***1,655,629***	***1,714,403***	***807,499***	***836,165***	***865,849***	***896,587***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,474,515***	**5,783,521**	
TOTAL CAPITAL	**171,686**	**6,608,231**	**14,411,173**	**10,048,307**	**13,491,578**	**10,910,457**	**7,146,728**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**85,321,307**	**60,643,052**	
O&M ITEMS - SUMMARY																							
Deployment																							
O&M in support of capital deployment	0	85,389	229,582	130,186	194,892	203,447	154,590	157,790	161,056	164,390	0	0	0	0	0	0	0	0	0	0	**1,481,321**	**1,025,692**	**Direct and Tangible**
TOTAL - Asset Operations	***0***	***85,389***	***229,582***	***130,186***	***194,892***	***203,447***	***154,590***	***157,790***	***161,056***	***164,390***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,481,321***	**1,025,692**	
Ongoing Support																							
On-going Asset/Device support	0	9,416	34,927	50,006	72,532	96,468	115,512	135,303	155,864	177,218	180,886	184,630	188,452	192,353	196,335	200,399	204,547	208,781	213,103	217,514	**2,834,248**	**1,296,703**	**Direct and Tangible**
Component Replacements	0	2,742	10,171	14,562	21,121	28,092	33,637	39,400	45,387	51,606	52,674	53,764	54,877	56,013	57,173	58,356	59,564	60,797	62,056	63,340	**825,333**	**377,600**	**Direct and Tangible**
On-going Communications Network costs	0	7,324	27,166	38,894	56,414	75,031	89,843	105,236	121,227	137,836	140,689	143,601	146,574	149,608	152,705	155,866	159,092	162,386	165,747	169,178	**2,204,415**	**1,008,547**	**Direct and Tangible**
Vendor costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Training	0	10,355	10,723	11,103	11,497	11,906	12,328	12,766	13,219	13,688	14,174	14,677	15,199	15,738	16,297	16,875	17,474	18,095	18,737	19,402	**274,254**	**137,195**	**Direct and Tangible**
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Asset Contingency	0	1,974	7,321	10,482	15,204	20,221	24,213	28,361	32,671	37,147	37,916	38,701	39,502	40,320	41,154	42,006	42,876	43,763	44,669	45,594	**594,092**	**271,804**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***31,810***	***90,308***	***125,047***	***176,769***	***231,717***	***275,533***	***321,066***	***368,368***	***417,495***	***426,339***	***435,374***	***444,604***	***454,032***	***463,663***	***473,502***	***483,554***	***493,822***	***504,312***	***515,028***	***6,732,342***	**3,091,849**	
Communications Network																							
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	
TOTAL O&M	**43,800**	**184,182**	**399,980**	**336,662**	**477,080**	**631,673**	**552,674**	**478,856**	**529,425**	**581,885**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**8,910,447**	**4,639,301**	
GRAND TOTAL CAPITAL & O&M	**215,486**	**6,792,413**	**14,811,154**	**10,384,969**	**13,968,659**	**11,542,130**	**7,699,402**	**7,804,518**	**8,038,826**	**8,279,967**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**94,231,754**	**65,282,354**	

Northern States Power Company
FLISR Cost Benefit Analysis

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	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
O&M BENEFITS											
Operational Benefits	0	0	0	0	0	0	0	0	0	0	0
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS											
Customer Minutes Out- CMO Patrolling savings	0	0	0	40,757	175,083	271,514	355,725	453,382	539,313	649,433	725,847
Customer Minutes Out- CMO Customer Savings	0	0	0	2,754,556	4,809,980	6,277,181	8,295,139	10,426,430	12,214,741	14,325,875	15,433,977
TOTAL CUSTOMER IMPACTS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**
GRAND TOTAL BENEFITS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**

	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
O&M BENEFITS											
Operational Benefits	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS											
Customer Minutes Out- CMO Patrolling savings	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	**10,316,013**	**4,528,044**
Customer Minutes Out- CMO Customer Savings	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	**220,019,300**	**98,458,717**
TOTAL CUSTOMER IMPACTS	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**
GRAND TOTAL BENEFITS	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**

NSPM FLISR- ***NPV***	**Total ($MM)**
Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(78)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

RATIO SENSITIVITY	VALUE
FAN(15% WiMax)+ Contingencies	**1.31**
FAN(15% WiMax) NO Contingencies	**1.53**

Northern States Power Company
IVVO Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189	
CAPITAL COSTS																						
Assets/Devices																						
Device costs	0	0	1,512,735	2,824,978	2,704,856	2,267,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,310,319**	**6,996,776**
Device Installation costs	0	0	357,063	773,839	777,449	679,695	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,588,046**	**1,936,047**
Xcel Personnel	0	0	132,317	272,663	277,896	283,603	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**966,479**	**720,811**
Xcel Distribution Personnel [ADMS IVVO Integration]	0	0	306,666	525,184	771,477	772,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,375,999**	**1,760,061**
External resources (Consultants, contractors etc.)	0	0	187,008	434,397	443,389	342,887	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,407,681**	**1,054,169**
E&S	0	103,550	750,582	777,228	804,819	833,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,269,570**	**2,482,269**
Varentec Engineering (ENGO,caps,ami)	0	0	416,731	425,358	434,163	443,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,719,402**	**1,299,884**
Contingency	0	0	107,914	269,162	256,986	175,088	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**809,149**	**607,879**
TOTAL - Business Assets/Devices	***0***	***103,550***	***3,771,016***	***6,302,808***	***6,471,034***	***5,798,235***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***22,446,644***	**16,857,896**
Communications Network																						
Communications Operations-IVVO Budget	0	0	61,332	115,547	110,814	104,193	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**391,886**	**293,733**
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**409,298**	**348,698**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Bus Sys WiMAX Cost	20,915	625,692	1,081,829	726,163	687,157	186,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,327,784**	**2,666,303**
FAN Bus Sys Contingency	0	0	0	1,482,861	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,482,861**	**1,155,589**
TOTAL - Communications	41,073	756,817	1,401,176	2,324,571	797,971	290,222	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***5,611,829***	**4,464,323**
IT Systems and Integration																						**0**
Xcel Personnel [ADMS IVVO Integration]	0	0	803,466	1,375,982	2,021,270	2,024,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,225,118**	**4,611,361**
External resources (Consultants, contractors etc.) [GEMS]	0	0	520,914	265,849	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**786,763**	**639,234**
GEMS hardware	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Varentec PM & Services	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Project Management	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Travel Expenses	0	0	10,418	5,317	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,735**	**12,785**
Security	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Contingency	0	0	130,158	158,367	190,817	188,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**667,722**	**500,682**
Program Management	0	0	104,183	319,018	325,622	332,362	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,081,185**	**802,089**
TOTAL - IT Systems and Integration	***0***	***0***	***1,881,688***	***2,284,042***	***2,537,708***	***2,545,144***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***9,248,582***	**6,949,692**
Program Management																						
Organizational Change Management	0	0	468,823	850,715	651,244	553,937	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,524,720**	**1,909,732**
TOTAL - Program Management	***0***	***0***	***468,823***	***850,715***	***651,244***	***553,937***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***2,524,720***	**1,909,732**
TOTAL CAPITAL	**41,073**	**860,367**	**7,522,703**	**11,762,136**	**10,457,957**	**9,187,538**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**39,831,775**	**30,181,642**
O&M ITEMS																						
O&M in support of capital deployment	0	0	17,731	37,764	33,658	34,745	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**123,898**	**92,683**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***17,731***	***37,764***	***33,658***	***34,745***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***123,898***	**92,683**
Assets/Devices																						
On-going Asset/Device support	0	0	0	0	7,991	25,537	40,714	57,063	59,089	61,187	63,359	65,608	67,937	70,349	72,847	75,433	78,110	80,883	83,755	86,728	**996,591**	**433,842**
Device Replacements	0	0	0	0	12,059	38,654	62,172	85,943	87,722	89,538	91,391	93,283	95,214	97,185	99,197	101,250	103,346	105,485	107,669	109,897	**1,380,003**	**609,942**
Training	0	0	0	0	195	653	1,107	1,554	1,609	1,666	1,725	1,786	1,850	1,915	1,983	2,054	2,127	2,202	2,280	2,361	**27,066**	**11,765**
Contingency	0	0	0	0	2,471	7,885	12,612	17,431	17,792	18,160	18,536	18,920	19,312	19,711	20,119	20,536	20,961	21,395	21,838	22,290	**279,968**	**123,761**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***0***	***0***	***22,715***	***72,730***	***116,604***	***161,991***	***166,212***	***170,551***	***175,011***	***179,597***	***184,312***	***189,161***	***194,146***	***199,272***	***204,544***	***209,965***	***215,541***	***221,276***	***2,683,629***	**1,179,310**
Communications Network																						
On-going Communications Network costs	0	0	0	0	4,920	15,829	25,585	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	**567,832**	**250,941**
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN WiMAX Cost	14,600	22,328	26,697	27,143	35,140	65,503	40,850	0	0	0	0	0	0	0	0	0	0	0	0	0	**232,261**	**173,920**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	***14,600***	***22,328***	***26,697***	***27,143***	***40,060***	***81,332***	***66,435***	***35,371***	***36,103***	***36,850***	***37,613***	***38,392***	***39,187***	***39,998***	***40,826***	***41,671***	***42,533***	***43,414***	***44,312***	***45,230***	***800,094***	**424,861**
IT Systems and Integration																						
Program Management	0	0	22,576	35,446	36,180	36,929	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**131,132**	**98,245**
TOTAL - IT Systems and Integration	***0***	***0***	***22,576***	***35,446***	***36,180***	***36,929***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***131,132***	**98,245**
Business Program Management																						
Organizational Change Management	0	0	156,274	283,572	217,081	184,646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**841,573**	**636,577**
TOTAL - Program Management	***0***	***0***	***156,274***	***283,572***	***217,081***	***184,646***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***841,573***	**636,577**
TOTAL O&M	**14,600**	**22,328**	**223,278**	**383,926**	**349,694**	**410,382**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**4,580,325**	**2,431,676**
GRAND TOTAL CAPITAL & O&M	**55,673**	**882,695**	**7,745,981**	**12,146,062**	**10,807,651**	**9,597,920**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**44,412,100**	**32,613,318**

Northern States Power Company
IVVO Cost Benefit Analysis

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
OTHER BENEFITS																						
Energy Savings																						
Energy Reduction	0	0	165,891	423,491	910,125	1,577,997	1,904,520	1,963,148	2,014,173	2,063,569	2,041,390	1,994,758	2,019,200	2,085,180	2,025,146	2,026,282	2,185,792	2,206,891	2,172,820	2,129,363	**31,909,736**	$14,934,748
Loss Savings	0	0	3,155	8,234	18,167	32,238	39,806	41,776	43,440	44,870	45,454	45,229	46,713	49,088	48,089	48,350	52,370	53,018	52,442	52,442	**724,883**	$333,272
Total Fuel Savings	0	0	169,046	431,724	928,293	1,610,235	1,944,326	2,004,924	2,057,613	2,108,438	2,086,844	2,039,988	2,065,913	2,134,268	2,073,236	2,074,632	2,238,162	2,259,909	2,225,262	2,181,806	**32,634,620**	$15,268,020
Carbon Emissions Benefits																						
Carbon Reduction	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
Total Carbon Emissions Savings	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
TOTAL OTHER BENEFITS	**0**	**0**	**263,744**	**662,427**	**1,407,660**	**2,253,415**	**2,600,664**	**2,650,912**	**2,595,141**	**2,449,229**	**2,399,557**	**2,349,085**	**2,369,024**	**2,419,147**	**2,389,718**	**2,403,054**	**2,579,322**	**2,605,171**	**2,574,626**	**2,535,271**	39,507,168	**$18,867,844**
DEMAND BENEFITS																						
Deferral of Capital Investments As Demand Reduction	0	0	45,106	113,532	227,415	386,537	456,612	457,807	459,632	460,716	460,890	465,302	468,166	470,601	475,990	480,620	485,452	488,836	495,037	489,665	**7,387,915**	$3,481,566
TOTAL DEMAND	**0**	**0**	**45,106**	**113,532**	**227,415**	**386,537**	**456,612**	**457,807**	**459,632**	**460,716**	**460,890**	**465,302**	**468,166**	**470,601**	**475,990**	**480,620**	**485,452**	**488,836**	**495,037**	**489,665**	7,387,915	**$3,481,566**
GRAND TOTAL DEMAND & OTHER BENEFITS	**0**	**0**	**308,850**	**775,959**	**1,635,075**	**2,639,951**	**3,057,277**	**3,108,719**	**3,054,774**	**2,909,945**	**2,860,447**	**2,814,387**	**2,837,189**	**2,889,748**	**2,865,708**	**2,883,673**	**3,064,774**	**3,094,007**	**3,069,663**	**3,024,937**	46,895,083	**$22,349,410**

NSPM IVVO- ***NPV***	**Total ($MM)**
Benefits	**22**
Other Benefits	19
CAP Benefits	3
Costs	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (DVO 1.25% O&M; 0.7% capital)	**0.57**

RATIO BASE (DVO Savings 1.25% O&M, 0.7% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.57**
FAN(5% WiMax) NO Contingencies	**0.61**

RATIO LOW SENSITIVITY (DVO Savings 1% O&M, 0.6% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.46**
FAN(5% WiMax) NO Contingencies	**0.49**

RATIO HIGH SENSITIVITY (DVO Savings 1.5% O&M, 0.8% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.67**
FAN(5% WiMax) NO Contingencies	**0.72**

Northern States Power Company
AMI Pricing and CO2 Benefits Summary

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
OTHER BENEFITS																			
Load Flexibility Benefits																			
Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	19,965,050	20,415,850	21,129,600	21,780,000	22,361,590	23,136,860	23,755,800	24,531,638	25,336,224	26,164,958	27,023,654	27,910,308	**283,511,530**	**138,479,332**
Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	1,819,116	1,975,194	2,019,888	2,037,750	2,133,144	2,262,273	2,392,520	2,517,599	2,573,992	2,725,849	2,753,107	2,780,638	**27,991,070**	**13,576,886**
Time Of Usage-TOU-Avoided CO2 Emissions	0	0	0	0	0	226,876	352,119	485,400	361,972	230,903	344,421	271,720	330,772	309,477	297,166	310,767	413,652	**3,935,245**	**1,961,868**
TOTAL - Load Flexibility Benefits	0	0	0	0	0	22,011,042	22,743,163	23,634,888	24,179,722	24,725,637	25,743,554	26,420,040	27,380,008	28,219,692	29,187,972	30,087,528	31,104,598	***315,437,845***	***154,018,085***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,848,467**	**25,792,193**	**30,477,932**	**31,546,259**	**32,271,937**	**33,003,045**	**34,210,616**	**35,081,332**	**36,240,224**	**37,283,648**	**38,460,605**	**39,573,907**	**40,809,920**	**416,600,086**	**203,424,492**

The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory

PREPARED FOR

Xcel Energy

PREPARED BY

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THE Brattle GROUP

Notice

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Executive Summary

Highlights:

- This study estimates the amount of cost-effective demand response available in Xcel Energy's Northern States Power (NSP) service territory, including an assessment of emerging "load flexibility" programs that can capture advanced sources of value such as geo-targeted distribution investment deferral and grid balancing services.
- Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and grid balancing services, and relatively high costs of emerging DR technologies.
- In later years of the study horizon, and under conditions that are more favorable to the economics of DR, cost-effective DR potential increases significantly, exceeding the PUC's 400 MW DR procurement requirement.
- New, emerging load flexibility programs account for around 30% of the 2030 incremental DR potential estimates in this study.

Background

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory through 2030.[1] The study addresses the Minnesota PUC's requirement that NSP "acquire no less than 400 MW of additional demand response by 2023" and "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

The scope of this study extends significantly beyond those of prior studies. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies

[1] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions.

This study also takes a detailed approach to assessing the cost-effectiveness of each DR option. While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

The Brattle Group's Load*Flex* model is used to assess NSP's emerging DR opportunities. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program, thus providing a more complete estimate of total cost-effective potential than prior methodologies.
- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. This includes accounting for the market saturation of various end-use appliances, customer segmentation based on size, and NSP's estimates of the capability of its existing DR programs.
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program, including tariff-related program limitations and an hourly representation of load control capability for each program.
- **Realistic accounting for "value stacking":** DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program and accounting for necessary tradeoffs when pursuing multiple value streams.
- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings, a review of experience and studies in other jurisdictions, and conversations with vendors.

Findings

Base Case

NSP currently has one of the largest DR portfolios in the country, with 850 MW of load curtailment capability (equivalent to roughly 10% of NSP's system peak). The portfolio primarily consists of an interruptible tariff program for medium and large C&I customers, and a residential air-conditioning direct load control (DLC) program. The DLC program is transitioning from utilizing a conventional compressor switch technology to instead leveraging newer smart thermostats.

There is an opportunity to tap into latent interest in the current NSP programs and grow participation in those existing programs through new marketing efforts. According to our analysis, doing so could provide 293 MW of incremental cost-effective potential by 2023. The majority of this growth could come from increased enrollment in the interruptible tariff program for the medium and large C&I segments, and from the transition to a residential air-conditioning DLC program that more heavily utilizes smart thermostat technology.

NSP's DR portfolio could also be expanded to include new programs that are not currently offered by the company. Our analysis considered eight new programs, including time-of-use (TOU) rates, critical peak pricing (CPP), home and workplace EV charging load control, timer-based water heating load control and a more advanced "smart" water heating program, behavioral DR, ice-based thermal storage, and automated DR for lighting and HVAC of commercial and industrial customers. Some of these programs could provide ancillary services and geo-targeted distribution deferral benefits, in addition to the conventional DR value streams.

Based on current expectations about the future characteristics of the NSP market, smart water heating is the only new program that we find to be cost-effective in 2023 among the emerging options described above, providing an additional 13 MW of incremental cost-effective potential. Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and frequency regulation, and relatively high costs of emerging DR technologies.

This expanded portfolio, which reflects all cost-effective DR options available to NSP across a broad range of potential use cases, would fall short of the PUC's 2023 procurement requirement. In 2023, the current portfolio plus the incremental cost-effective DR identified in this study would equate to 1,156 MW of total peak reduction capability, 154 MW short of the procurement requirement.[2]

In 2025, the potential in the expanded portfolio increases. This increase is driven primarily by the ability to begin offering time-varying rates once smart meters are fully deployed in 2024. However, it is likely that several years will be needed for smart metering-based programs to ramp up to full participation, so the incremental potential associated with these programs is still somewhat constrained in 2025. The current portfolio plus the incremental DR in the expanded portfolio equate to 1,243 MW of cost-effective DR potential in 2025.

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2 NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when additionally accounting for line losses.

By 2030, NSP's cost-effective DR potential will increase further. This increase is driven primarily by the maturation of smart metering-based DR programs. Other factors contributing to the increase in cost-effective potential include a continued transition to air-conditioning load control through smart thermostats, an expansion of the smart water heating program through ongoing voluntary replacements of expiring conventional electric water heaters, and overall growth in NSP's customer base. By 2030, we estimate that NSP's current portfolio plus the incremental cost-effective DR would amount to 468 MW. New, emerging DR programs account for 33% of the incremental potential. Achieving this potential would require not only growth in existing programs, but the design and implementation of several new DR program as well.

High Sensitivity Case

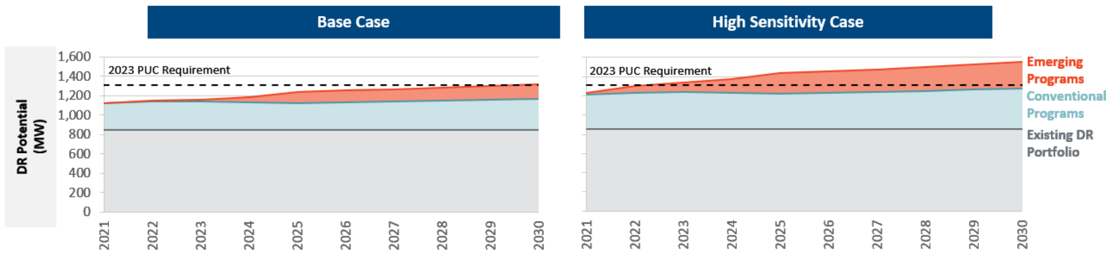
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the costs of emerging DR technologies may decline significantly, or the cost of competing resources (e.g., peaking capacity) may be higher than expected. To understand how these alternative conditions would impact DR potential, we analyzed a sensitivity case. The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. The case is not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative assumptions of the High Sensitivity Case there is significantly more cost-effective incremental potential. In 2023 there is a total of 484 MW of incremental cost effective potential, which would satisfy the PUC's procurement requirement. By 2030, the total portfolio of DR programs, including the existing programs, could reach 705 MW.

The mix of cost-effective programs in the High Sensitivity case is essentially the same as in the Base Case. However, larger program benefits justify higher incentive payments, which leads to higher participation and overall potential in these programs. Auto-DR for C&I customers also presents an opportunity to increase load flexibility in the High Sensitivity Case, though the potential in this program is subject to uncertainty in technology cost and customer adoption.

Under both the Base Case and the High Sensitivity Case assumptions, avoided generation capacity costs are the primary benefit of the DR portfolio. In the High Sensitivity Case, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Figure ES-1 summarizes the DR potential estimates and benefits of the DR portfolio under Base Case and High Sensitivity Case assumptions.

Figure ES-1: NSP's DR Potential and Annual Portfolio Benefits



2030 Avoided Cost ($M/yr)

Base Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

High Sensitivity Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

An expanded portfolio of DR programs will have operational flexibility beyond the capabilities of conventional existing programs. For instance, load flexibility programs could be dispatched to reduce the system peak, but also to address local peaks on the distribution system which may occur during later hours of the day. Off-peak load building through electric water heating could help to mitigate wind curtailments and take advantage of negative energy prices. The provision of frequency regulation from electric water heaters could further contribute to renewables integration value.

Specific recommendations for acting on the findings of this study including the following:

- Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program.
- Pilot and deploy a smart water heating program. As a complementary activity, evaluate the impacts of switching from gas to electric heating, accounting for the grid reliability benefits associated with this flexible source of load.
- Prior to the smart metering rollout, build the foundation for a robust offering of time-varying rates, including identifying rate options that could be offered on an opt-out basis.
- Develop measurement & verification (M&V) 2.0 protocols to ensure that program impacts are dependable and can be integrated meaningfully into resource planning efforts.
- Design programs with peak period flexibility, to be able to respond to changes such as a shifts in the net peak due to solar PV adoption, or a shift in the planning emphasis from a focus on the MISO peak to a focus on more local peaks, for instance.

I. Introduction

Purpose

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory.[3] Xcel Energy commissioned this study to satisfy the requirements of the Minnesota Public Utilities Commission (PUC) Order in Docket No. E-002/RP-15-21. That Order, established in January 2017, required NSP to "acquire no less than 400 MW of additional demand response by 2023" and to "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

Background

The Brattle Group conducted an assessment of NSP's DR potential in 2014.[4] That study specifically addressed opportunities to reduce NSP's system peak demand. As such, the assessment had a primary focus on "conventional" DR programs that are utilized infrequently to mitigate system reliability concerns. The study also included price-based DR options that would be enabled by the eventual deployment of smart meters.

The scope of this 2018 study extends significantly beyond that of the 2014 study. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions. The Brattle Group's Load*Flex* model is used to assess these emerging opportunities.

3 Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

4 Ryan Hledik, Ahmad Faruqui, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," prepared for Xcel Energy, April 2014.

This 2018 study also extends beyond the scope of the 2014 study by evaluating the cost-effectiveness of each DR option.[5] While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A utility with significant market penetration of solar PV may find the most value in advanced load shifting capabilities that address evening generation ramping issues on a daily basis, whereas a system with a near-term need for peaking capacity may find more value in the types of conventional DR programs that reduce the system peak during only a limited number of hours per year. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

This report summarizes the key findings of The Brattle Group's assessment of NSP's DR market potential. Additional detail on methodology and results is provided in the appendices.

NSP's Existing DR Portfolio

The capability of NSP's existing DR portfolio is substantial. It is the eighth largest portfolio among all US investor-owned utilities when DR capability is expressed as a percentage of peak demand. The portfolio is the largest in MISO in terms of total megawatt capability, and second when expressed as a percentage of peak demand.

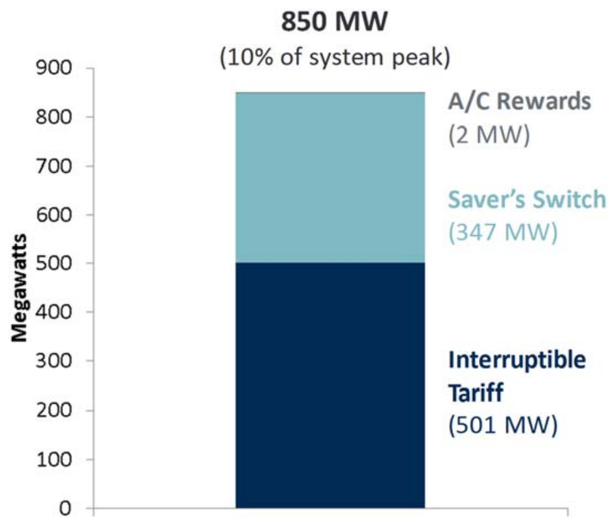
As of 2017, Xcel Energy had 850 MW of DR capability across its NSP service territory, accounting for roughly 10 percent of system peak demand. This capability comes primarily from two programs. The largest is an "interruptible tariff" program, which provides commercial and industrial (C&I) customers with energy bill savings in return for a commitment to curtail electricity demand to pre-established levels when called upon by the utility. Roughly 11 percent of the peak-coincident demand of medium and large C&I customers is enrolled in this program.

The second program is NSP's Saver's Switch program. Saver's Switch is a conventional residential load control program, in which the compressor of a central air-conditioning unit or the heating element of an electric resistance water heater is temporarily cycled off to reduce electricity demand during DR events. Saver's Switch is one of the largest such programs in the country. Roughly 52 percent of all eligible residential customers (i.e., those with central air-conditioning) are enrolled in the program, accounting for around 29% of all of NSP's residential customers. Saver's Switch is gradually being transitioned to a program based on newer smart thermostat technology, called "A/C Rewards." A/C Rewards contributes an additional 2 MW to

[5] The 2014 study developed a "supply curve" of DR options available to NSP as inputs to its integrated resource plan (IRP), but did not explicitly evaluate the extent to which those options would be less costly than serving electricity demand through the development of new generation resources.

NSP's existing DR capability, though this is expected to grow significantly in coming years. A summary of NSP's DR portfolio is provided in Figure 1.

Figure 1: NSP 2017 DR Capability



Sources: NSP 2017 DR program data and 2017 NSP system peak demand (8,546 MW)

Important Considerations

The focus of this study is on quantifying the amount of cost-effective DR capability that can be achieved above and beyond NSP's current 850 MW DR portfolio. We estimate the incremental DR potential that can be achieved through an expansion of existing program offerings, the introduction of new programs, and consideration of a broad range of potential system benefits that are available through DR. Specifically, this study is structured to quantify all DR potential that satisfies the following three conditions:

1. **Incremental:** All quantified DR potential is incremental to NSP's existing 850 MW DR portfolio.[6]

2. **Cost-effective:** The present value of avoided resource costs (i.e., benefits) must outweigh program costs, equipment costs, and incentives.

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6 For the purposes of this analysis, all incremental potential estimates assume NSP's portfolio of existing programs continues to be offered as currently designed in future years, and that the 850 MW impact persists throughout the forecast horizon.

3. **Achievable:** Program enrollment rates are based on primary market research in NSP's service territory and supplemented with information about utility experience in other jurisdictions.

The findings of this study should be interpreted as a quantitative screen of the DR opportunities available to NSP. Further development of individual programs, and testing of the programs through pilots, will provide additional insight regarding the potential benefits and costs that such programs may offer to NSP and its customers when deployed on a full scale basis.

II. Methodology

This study analyzes three ways to increase the capability of NSP's existing DR portfolio. First, we assess the potential to increase enrollment in existing programs. Increased enrollment could be achieved through targeted program marketing efforts, for example. Second, the menu of DR programs offered to customers could be expanded to include new, non-conventional options. These non-conventional options include emerging "load flexibility" programs which go beyond peak shaving to provide around-the-clock decreases and increases in system load. Third, consistent with the introduction of more flexible DR programs, we consider a broadened list of potential benefits in the cost-effectiveness screening process, such as ancillary services and geographically-targeted deferral of distribution capacity upgrades.

Conventional DR Programs

Our analysis considers conventional DR programs that have been offered by utilities for many years, including in some cases by NSP.

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch on the compressor. The modeled program is based on NSP's Savers Switch program.

- **Smart thermostats:** An alternative to conventional DLC, smart thermostats allow the temperature setpoint to be remotely controlled to reduce A/C usage during peak times. The modeled program is based on NSP's A/C Rewards program, which provides customers with options to use their own thermostat, self-install a thermostat purchased from NSP's online store, or use a NSP-installed thermostat. Smart thermostat programs are based on newer technology than the other "conventional" DR programs in this list, but included here as the program is already offered by NSP.

- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate.

- **Demand bidding:** Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty. While a conventional option, demand bidding is not currently offered by NSP.

Non-conventional DR Programs

Pricing programs are one type of non-conventional DR option. We consider two specific time-varying rate options which generally span the range of impacts that can be achieved through pricing programs: A static time-of-use rate and a dynamic critical peak pricing rate.

- **Time-of-use (TOU) rate:** Currently being piloted by NSP for residential customers and offered on a full-scale basis to C&I customers. Static price signal with higher price during peak hours (assumed 5-hour period aligned with system peak) on non-holiday weekdays. Modeled as being offered on an opt-in and an opt-out (default) basis. The study also includes an optional TOU rate for EV charging.

- **Critical peak pricing (CPP) rate:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1/kWh) during peak hours on 10 to 15 days per year. CPP rates are modeled as being offered on both an opt-in and an opt-out (default) basis.

The second category of non-conventional DR programs relies on a variety of advanced behavioral and technological tools for managing customer electricity demand.

- **Behavioral DR:** Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

- **EV managed charging:** Using communications-enabled smart chargers allows the utility to shift charging load of individual EVs plugged-in from on-peak to off-peak hours. Customers who do not opt-out of an event receive a financial incentive. The managed EV charging program was modeled on three recent pilots: PG&E (with BMW), United Energy (Australia), and SMUD. Allows curtailment of charging load for up to three hours per day, fifteen days per year. Impacts were modeled for both home charging and workplace charging programs.

- **Timed water heating:** The heating element of electric resistance water heaters can be set to heat water during off-peak hours of the day. The thermal storage capabilities of the water tank provide sufficient hot water during peak hours without needing to activate the heating element.

- **Smart water heating:** Offers improved flexibility and functionality in the control of the heating element in the water heater. The thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. Modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

- **Ice-based thermal storage:** Commercial customers shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day.

- **C&I Auto-DR:** Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting (both luminaire and zonal lighting options).

DR Benefits

This study accounts for value streams that are commonly included in assessments of DR potential:

- **Avoided generation capacity costs:** The need for new peaking capacity can be reduced by lowering system peak demand. Important considerations when estimating the equivalence of DR and a peaking generation unit are discussed later in this section of the report.

- **Reduced peak energy costs:** Reducing load during high priced hours leads to a reduction in energy costs. Our analysis estimates net avoided energy costs, accounting for costs associated with the increase in energy consumption during lower cost hours due to "load building." The energy benefit accounts for avoided average line losses. Our analysis likely includes a conservative estimate of this value, as peak line losses are greater than off-peak line losses. Our analysis does not include the effect of any potential change in energy market prices that may result from changes in load patterns (sometimes referred to as the "demand response induced price effect," or DRIPE). It is simply a calculation of reduced resource costs.

- **System-wide deferral of transmission and distribution (T&D) capacity costs.** System-wide reductions in peak demand can, on average, contribute to the reduced need for peak-driven upgrades in T&D capacity. We account for this potential value using methods that were established in a recent Minnesota PUC proceeding.[7]

This study also accounts for value streams that can be captured through more advanced DR programs:

- **Geo-targeted distribution capacity investment deferral:** DR participants may be recruited in locations on the distribution system where load reductions would defer the need for capacity upgrades. NSP's 5-year distribution plan was used to identify candidate deferral projects, and qualifying DR programs were evaluated based on their ability to contribute to the deferral.[8]

- **Ancillary services:** The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service (albeit with limited system need).

- **Load building / valley filling:** Load can be shifted to off-peak hours to reduce wind curtailments or take advantage of low or negatively priced hours. DR was dispatched against hourly energy price series to capture the economic incentive that energy prices provide for this service.

Figure 2 summarizes the ways in which this assessment of DR potential extends the scope of prior studies in Minnesota and other jurisdictions. In the figure, "X" indicates the value streams that each DR program is assumed to provide.

7 Minnesota PUC Docket No. E999/CIP-16-541.

8 The distribution plan was in-development at the time of our analysis. Distribution data was provided to Brattle in March 2018.

Figure 2: Options for Expanding the Existing DR Portfolio

1 Increase enrollment in the conventional portfolio

2 Extend DR value streams

3 Include non-traditional DR options

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted distribution capacity deferral	Valley filling/ Load building	Ancillary services
Direct load control (DLC)	X	X	X			
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Smart thermostat	X	X	X			
Time-of-use (TOU) rates	X	X	X			
Dynamic pricing	X	X	X			
Behavioral DR	X	X	X			
EV managed charging	X	X	X	X	X	
Smart water heating	X	X	X		X	X
Timed water heating	X	X	X		X	
Ice-based thermal storage	X	X	X	X	X	
C&I Auto-DR	X	X	X	X	X	X

Notes: "X" indicates the value streams that each DR option is assumed to be able to provide.

Defining DR Potential

We use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to determine the cost-effectiveness of the incremental DR portfolio. The UCT determines whether a given DR program will increase or decrease the utility's revenue requirement. This is the same perspective that utilities take when deciding whether or not to invest in a supply-side resource (e.g., a combustion turbine) through the IRP process.[9] Since the purpose of this DR potential study is to determine the amount of DR that should be included in the IRP, the UCT was determined to be the appropriate perspective. Major categories of benefits and costs included in the UCT are summarized Table 1.

[9] According to the National Action Plan for Energy Efficiency: "The UCT is the appropriate cost test from a utility resource planning perspective, which typically aims to minimize a utility's lifecycle revenue requirements."

Table 1: Categories of Benefits and Costs included in the Utility Cost Test

Benefits	Costs
Avoided generation capacity	Incentive payments
Avoided peak energy costs	Utility equipment & installation
Avoided transmission capacity	Administration/overhead
Avoided distribution capacity	Marketing/promotion
Ancillary services	

Throughout this study, we quantify DR potential in two different ways:

Technical Potential: Represents achievable potential without consideration for cost-effectiveness. In other words, this is a measure of DR capability that could be achieved from anticipated enrollment associated with a moderate participation incentive payment, regardless of whether or not the incentive payment and other program costs exceed the program benefits. As it is used here, the term "technical potential" differs from its use in energy efficiency studies. Technical potential in energy efficiency studies assumes 100% participation, whereas we assume an achievable level of participation in this assessment of DR potential.

Cost-effective Potential: Represents the portion of technical potential that can be obtained at cost-effective incentive payment levels. For each program, the assumed participation incentive payment level is set such that the benefit-cost ratio is equal to 1.0. Participation rates are estimated to align with this incentive payment level. When non-incentive costs (e.g., equipment and installation costs) are found to outweigh the benefits alone, the benefit-cost ratio is less than 1.0 and there is no opportunity to offer a cost-effective participation incentive payment. In that case, the program is considered to have no cost-effective potential.

The Load*Flex* Model

The Brattle Group's Load*Flex* model was used to estimate DR potential in this study. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to NSP's experience with DR programs where available (e.g., impacts from existing DLC programs or dynamic pricing pilots).

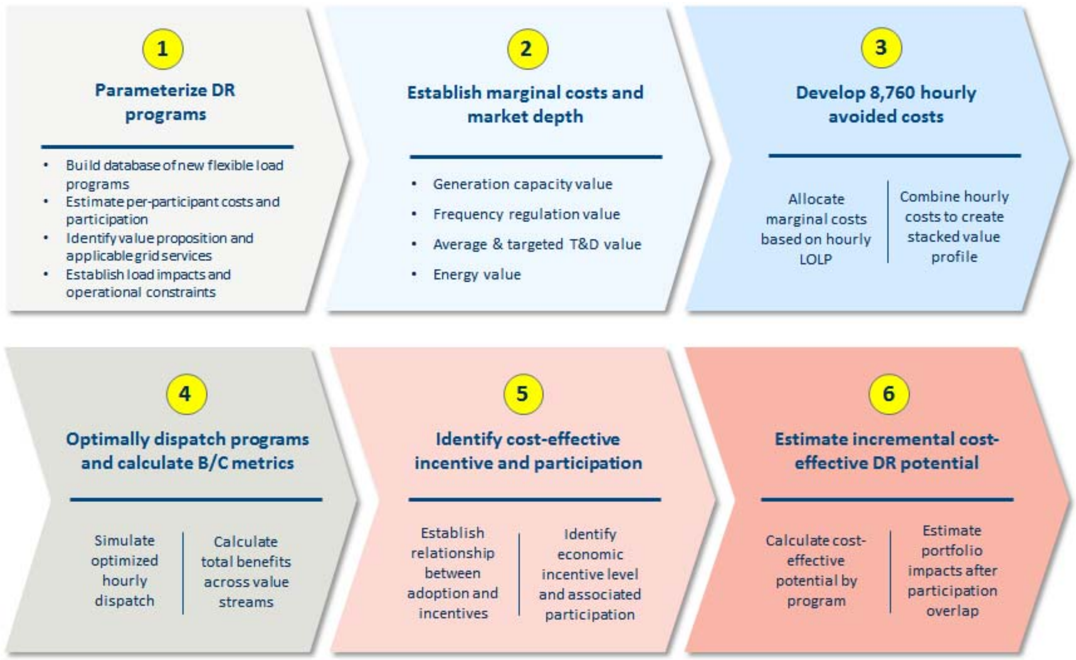
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local transmission or distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies of load flexibility value have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* modeling framework is organized around six steps, as summarized in Figure 3. Appendix A provides detail on the methodology behind each of these steps.

Figure 3: The Load*Flex* Modeling Framework



Modeling Scenarios

The value that DR will provide depends on the underlying conditions of the utility system in which it is deployed. Generation capacity costs, the anticipated need for new transmission and distribution (T&D) assets, and energy price volatility are a few of the factors that will determine DR value and potential. To account for uncertainty in NSP's future system conditions, we considered two modeling scenarios: A "Base Case" and a "High Sensitivity Case."

The **Base Case** most closely aligns with NSP's expectations for future conditions on its system, as defined in its IRP. The Base Case represents a continuation of recent market trends, combined with information about known or planned developments during the planning horizon.

The **High Sensitivity Case** was developed to illustrate how the value of DR can change under alternative future market conditions. The High Sensitivity Case is defined by assumptions about the future state of the NSP system and MISO market that are more favorable to DR program economics. The High Sensitivity Case is not intended to be the most likely future state of the NSP system. Relative to the Base Case, the High Sensitivity Case consists of a higher assumed generation capacity cost, more volatile energy prices due to greater market penetration of renewable generation, a significant reduction in emerging DR technology costs, and an increase in the need for frequency regulation.

Defining features of the two cases are summarized in Table 2. Appendix A includes more detail on assumptions and data sources behind the two cases.

Table 2: Defining Features of Base Case and High Sensitivity Case

	Base Case	High Sensitivity Case
Generation capacity (Net CONE)	$64/kW-yr (2018 NSP IRP)	$93/kW-yr (2018 EIA Annual Energy Outlook)
Hourly energy price	Based on MISO MTEP "Continued Fleet Change" case (15% wind+solar by 2032)	Based on MISO MTEP "Accelerated Fleet Change" case (30% wind+solar by 2032)
Frequency regulation	Price varies, 25 MW average need by 2030	Price same as Base Case, 50 MW average need by 2030
System average T&D deferral	Transmission: $3.6/kW-yr, Distribution: $9.5/kW-yr (2017 NSP Avoided T&D Study)	Same as Base Case
Geo-targeted T&D deferral	Value varies by distribution project, 90 MW eligible for deferral by 2030	Same as Base Case
DR technology cost	10% reduction from current levels by 2030 (in real terms)	30% reduction from current levels by 2030 (in real terms)

Notes: Unless otherwise specified, values shown are for year 2030 and in nominal dollars.

Modeling results are summarized for the years 2023 and 2030. 2023 is the year by which NSP must procure additional DR capability according to the Minnesota PUC's Order in Docket No. E-002/RP-15-21. The 2030 snapshot captures the potential for significant future changes in system conditions and their implications for DR value, and is consistent with the longer-term perspective of NSP's IRP study horizon. A summary of annual results, including intermediate years, is provided in Appendix D.

Data

To develop participation, cost, and load impact assumptions for this study, we relied on a broad range of resources. Where applicable, we relied directly upon information from NSP's experience with DR programs in its service territory. We also utilized the results of primary market research that was conducted directly with customers in NSP's service territory in order to better understand their preferences for various DR program options. Where NSP-specific information was unavailable, we reviewed national data on DR programs, DR potential studies from other jurisdictions, and DR program impact evaluations. A complete list of resources is provided in the References section and described further in Appendix A.

In an assessment of emerging DR opportunities, it is important to recognize that data availability varies significantly by DR program type. Conventional DR programs, such as air-conditioning load control, have decades of experience as full-scale deployments around the US and internationally. By contrast, emerging DR programs like EV charging load control have only recently begun to be explored, largely through pilot projects. Figure 4 summarizes data availability for each of the DR program types analyzed in this study.

Figure 4: Data Availability by DR Program Type

	Participation	Costs	Peak Impacts	Advanced Impacts
Residential				
Air-conditioning DLC	●	●	●	N/A
Smart thermostat	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Behavioral DR	◑	◑	◑	N/A
Smart water heating	◔	◔	◑	◔
Timed water heating	◔	◔	◑	◔
EV managed charging (home)	○	○	◔	N/A
EV charging TOU (home)	○	○	◔	N/A
C&I				
Interruptible tariff	●	●	●	N/A
Demand bidding	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Ice-based thermal storage	◔	◔	◔	◔
EV workplace charging	○	○	◔	N/A
Automated DR	○	◔	◔	○

Notes:

● NSP-specific data, including market research, pilot programs, and full-scale deployments

◑ Signficant program experience in other jurisdictions

◔ Some pilot or demonstration project experience in other jurisdictions

○ Speculative, estimated from theoretical studies and calibrated to NSP conditions

"Advanced impacts" refers to load flexibilty capability beyond conventional peak period reductions (e.g., frequency regulation)

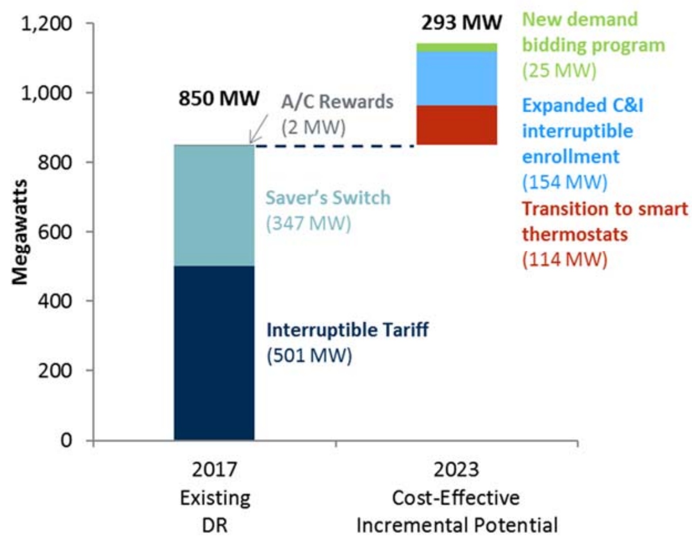
III. Conventional DR Potential in 2023

As an initial step in the assessment of NSP's cost-effective DR potential, we analyzed the potential if NSP were to deploy a portfolio of conventional DR programs. As defined for this study, conventional programs include interruptible tariffs, air-conditioning DLC, smart thermostats, and demand bidding. These program types are currently offered by NSP, with the exception of demand bidding. Therefore, the assessment of conventional programs is largely an assessment of the potential to grow the current DR portfolio through options such as new marketing initiatives or targeted marketing toward specific customer segments. We initially focus on the year 2023, as that is the year by which the Minnesota PUC has required NSP to procure additional DR capability.[10]

Figure 5 summarizes the cost-effective potential in a conventional DR portfolio in 2023. There is 293 MW of cost-effective incremental potential. Drivers of this potential include the expanded enrollment in NSP's interruptible tariff program, greater per-participant impacts that will be achieved as NSP continues to transition from a switch-based air-conditioning DLC program to a smart thermostat-based program, overall growth in NSP's customer base between 2017 and 2023, and a modest amount of potential in a new demand bidding program.

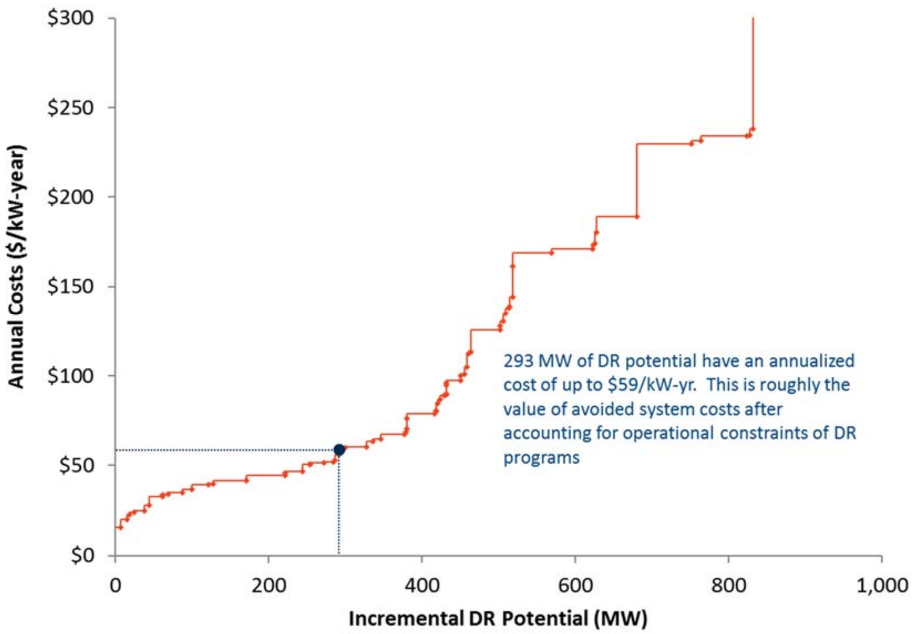
10 NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

Figure 5: Total DR Potential in 2023 (Conventional Portfolio)



The incremental potential in conventional DR programs can be expressed as a "supply curve." Figure 6 illustrates the costs associated with achieving increasing levels of DR capability. The upward slope of the curve illustrates how DR capability (i.e., enrollment) increases as incentive payments increase. The curve also captures the different costs and potential associated with each conventional DR program and applicable customer segment. Cost-effective DR capability is identified with the blue dotted line. There is roughly 293 MW of incremental DR potential available at a cost of less than $59/kW-year. That cost equates to the value of avoided system costs after accounting for the operational constraints of DR programs.

Figure 6: NSP's Incremental DR Supply Curve in 2023 (Conventional Portfolio)



Note: Supply curve shows conventional DR potential without accounting for cost-effectiveness. Potential estimates if the DR options were offered simultaneously as part of a portfolio at each price point (i.e. accounts for overlap). Program costs presented in nominal terms.

As discussed previously in this report, the Minnesota PUC has established a DR procurement requirement of 400 MW by 2023. It is important to clarify whether this 400 MW is a capacity-equivalent value, a generator-level value, or a meter-level value. Specifically, 1 MW of load reduction at the meter (or customer premise) avoids more than 1 MW at the generator level due to line losses between the generator and the customer. Further, 1 MW of load reduction at the generator level provides more than 1 MW of full capacity-equivalent value, as the load reduction would also avoid the additional capacity associated with NSP's obligation to meet the planning reserve requirement. Based on NSP's calculations, which account for line losses and the reserve requirement, 1 MW of load reduction at the meter level equates to 1.08 MW of load reduction at the generator level and 1.11 MW of capacity-equivalent value.

NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR. This equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses. These values are summarized in Table 3. Throughout this report, DR values are reported at the generator level. Thus, for consistency, we refer to the procurement requirement as a 391 MW generator-level value unless otherwise specified.

Table 3: NSP's 2023 DR Procurement Requirement

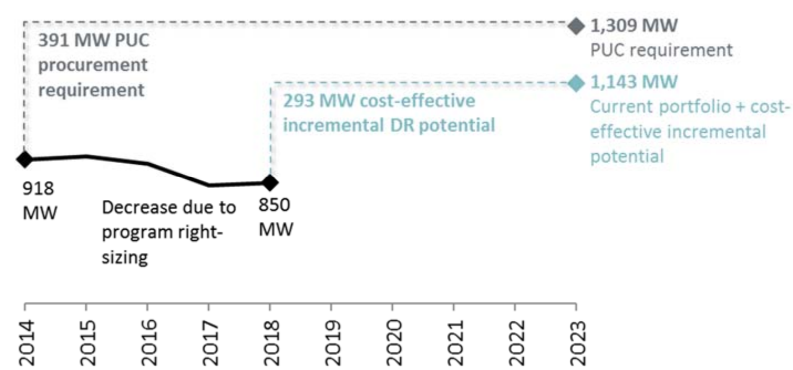
	Requirement (MW)	Notes
Meter level	361.7	Premise-level
Generator level	390.7	Grossed up for 8% line losses
Capacity equivalent	400.0	Grossed up for line losses and reserve requirement

Source: Calculations provided by NSP.

Our interpretation of the PUC's Order is that the required DR procurement is incremental to NSP's DR capability as it existed in 2014.[11] NSP had 918 MW of DR capability in 2014, leading to a total DR capability requirement of 1,309 MW in 2023. NSP's DR capability decreased between 2014 and 2017 largely due to an effort to ensure that enrolled load would be available for curtailment when called upon, thus leading to an incremental DR requirement that is larger than 391 MW (at the generator level).[12]

Combined with current capability of 850 MW, the incremental cost-effective DR potential in 2023 would result in a total portfolio of 1,143 MW. This estimate of cost-effective potential is 166 MW short of the PUC's DR procurement requirement. Figure 7 illustrates the gap between NSP's conventional DR potential and the DR procurement requirement.

Figure 7: NSP DR Capability (Conventional Portfolio)



Note: Chart is scaled such that vertical axis does not start at zero. 391 MW procurement requirement is expressed at the generator level and is equivalent to 400 MW of DR capacity.

11 2014 is the year of NSP's prior DR potential study, which was used to inform the Minnesota PUC's establishment of the DR procurement requirement.

12 For instance, some customers did not realize that they were participating in the program and dropped out when notified, or otherwise elected to reduce their enrolled load level.

IV. Expanded DR Potential in 2023

Given the shortfall of the conventional DR portfolio relative to the 2023 procurement target, it is relevant to consider if an expanded portfolio of DR options could mitigate the shortfall. We analyzed eight additional emerging DR programs that could be offered to up to four different customer segments (if applicable). As described in Section II, these emerging DR options include both price based programs (e.g., TOU and CPP rate designs) and technology-based programs (e.g., Auto-DR and smart water heating).

Base Case

Among the individual measures with the most *technical potential* in 2023 are HVAC Auto-DR for Medium C&I customers and thermal storage for commercial customers. Each of these programs has technical potential in excess of 100 MW.

Pricing programs and lighting Auto-DR for C&I customers, timed water heating programs, and behavioral DR compose the next tier of opportunities, with technical potential in each ranging between 50 and 100 MW. These programs generally have the potential to reach significant levels of enrollment or, alternatively, to provide deep load reductions among a smaller share of customers.

The Small C&I segment accounts for many of the DR programs with the lowest technical potential, as there is a relatively small share of load in this segment and these customers have historically demonstrated a lower willingness to participate in DR programs.

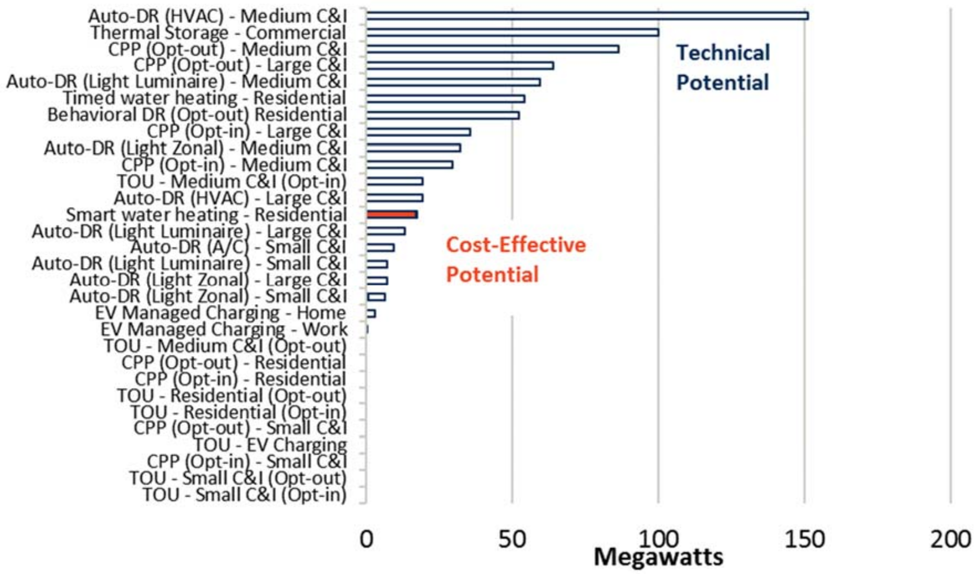
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

Pricing programs (i.e., TOU, CPP) cannot be offered on a full scale basis in 2023 to residential and small C&I customers, as AMI will not yet be fully deployed. Therefore, pricing programs have not been included in the potential estimates for 2023. Rollout of the programs is assumed to begin in 2024, upon NSP's projected completion of the AMI rollout.

Programs with significant *technical potential* do not necessarily have significant *cost-effective potential*. After accounting for cost-effectiveness under Base Case market conditions as well as technical constraints, the potential in DR programs is limited in 2023. Individually, only smart water heating and a modest amount of automated load control for C&I customers pass the cost-effectiveness screen. These programs pass the cost-effectiveness screen largely because they are capable of providing an expanded array of value streams, such as frequency regulation and geo-targeted T&D deferral.

Figure 8 summarizes the technical and cost-effective potential in each of the new DR program options. Potential is first shown for DR programs as if they were each offered in isolation.

Figure 8: New DR Program Potential in 2023 (Base Case)

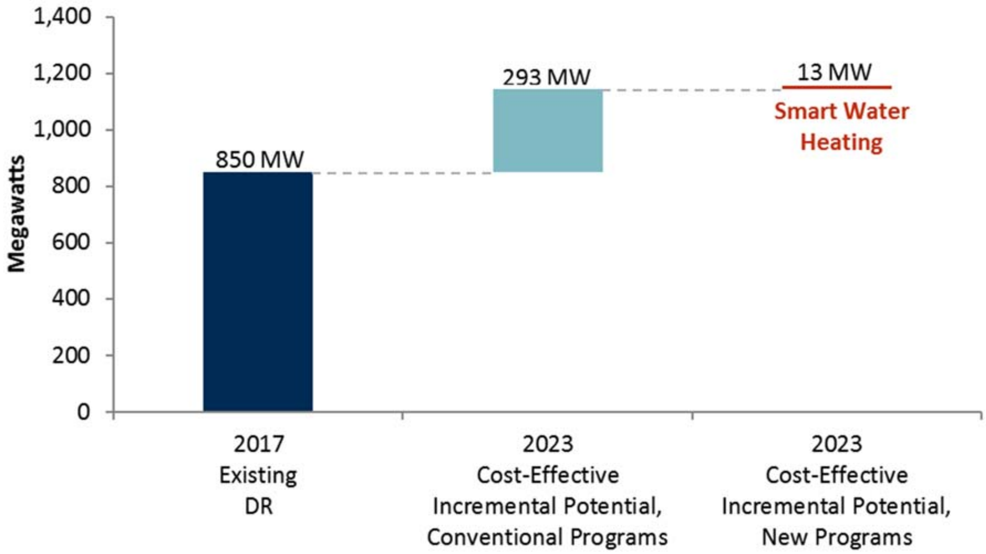


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The program-level DR impacts shown above cannot be added together to arrive at the potential capability of a DR portfolio. Adjustments must be made to account for double-counting of impacts when customers are enrolled in more than one program, and for limits on the need for certain value streams such as frequency regulation. Thus, combining the cost-effective programs into a portfolio can result in lower total potential DR capability than if the individual impacts shown above were simply summed.

In the 2023 scenario described above, the smart water heating program alone could satisfy NSP's need for frequency regulation. With that value stream no longer available to the Auto-DR program, the Auto-DR program fails the cost-effectiveness screen. **With the addition of the smart water heating program, NSP's cost-effective DR portfolio would increase by 13 MW. Achievement of all cost-effective DR potential would amount to total system-wide DR capability of 1,156 MW, but would still fall short of the PUC's procurement target by 154 MW.** The expanded capability in 2023 is illustrated in Figure 9.

Figure 9: Total DR Potential in 2023 (Expanded Portfolio)



Near-term Limitations on DR Value

The value of DR is very dependent on the characteristics of the system in which it is deployed. Several factors limit NSP's cost-effective DR in 2023, relative to other jurisdictions.

- **Low capacity prices:** NSP has access to low-cost peaking capacity, primarily due to the presence of brownfield sites that significantly reduce development costs. For instance, the all-in cost of a new combustion turbine in NSP's IRP is $63/kW-year, which is 23 percent lower than the cost of a CT assumed by the U.S. Energy Information Administration (EIA) in its Annual Energy Outlook (AEO). Similarly, a recent study approved by the Minnesota PUC determined that the average value of T&D capacity deferral achieved through reductions in customer consumption is approximately $11/kW-year in NSP's service territory.[13] This value, which was determined through a detailed bottom-up engineering assessment, is significantly lower than that of T&D deferral benefits observed in other studies, which can commonly reach values of $30/kW-year.[14] The value of T&D deferral is dependent on characteristics of the utility system and drivers of the investment need, and therefore varies significantly across utilities.

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13 Xcel Energy, "Minnesota Transmission and Distribution Avoided Cost Study," submitted to the Minnesota Department of Commerce, Division of Energy Resources (Department), July 31, 2017

14 Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

- **Metering technology limitations:** NSP has not yet deployed AMI, with an estimated forecast that system-wide AMI installation will be completed in 2024. AMI-based DR programs, such as time-varying rates and behavioral DR, cannot be offered to customers until deployment is complete. This effectively excludes the possibility of introducing any AMI-based programs in the year 2023.

- **High DR technology costs:** Some emerging DR programs depend on new technologies that have not yet experienced the cost declines that could be achieved at scale. While these technology costs could decrease over time, those reductions are not achieved in the early years of the study horizon.

- **Limited need for additional DR value streams:** While certain DR value streams potentially can be very valuable, these value streams can also be limited in need. For instance, our analysis of NSP's five-year distribution plan identified only 38 MW of projects that were potential candidates for geo-targeted capacity investment deferral. Those projects accounted for roughly 10 percent of the total value of NSP's plan. To qualify, projects need to satisfy criteria such as being driven by growth in demand and being of a certain size.[15] Similarly, while frequency regulation is often a highly-valued ancillary service and can be provided by certain types of DR, the need for frequency regulation across most markets is significantly less than one percent of system peak demand. This limits the amount of that value stream that can be provided by DR.

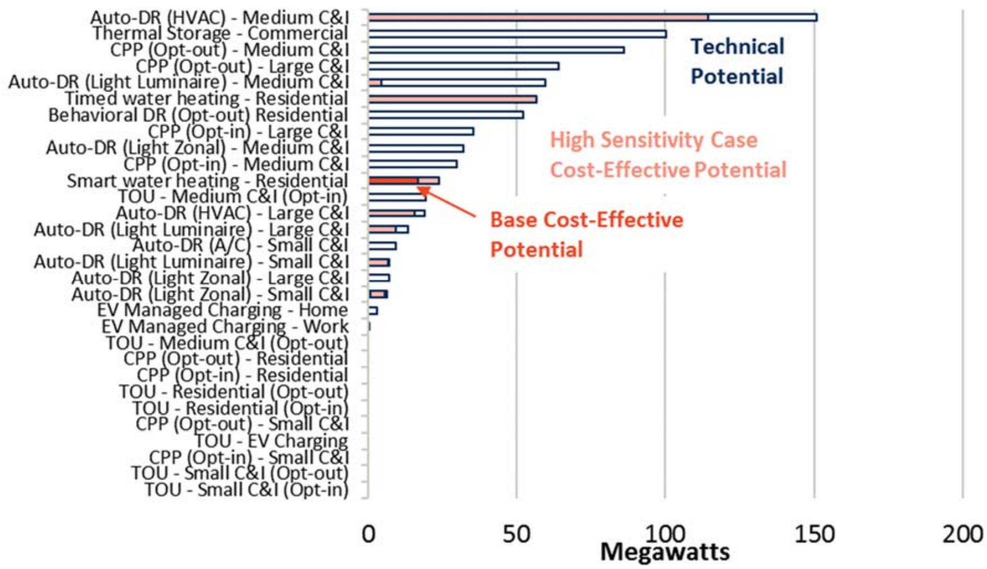
High Sensitivity Case

The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. As discussed earlier in this report, assumptions behind the High Sensitivity Case are not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative High Sensitivity Case assumptions, cost-effective DR potential increases significantly. Several programs that were not previously passing the cost-effectiveness screen, such as medium C&I HVAC-based Auto DR, residential timed water heating, and a small amount of lighting-based Auto-DR do pass the screen under the more favorable assumptions in this case. Figure 10 summarizes the increase in cost-effective potential at the individual program level.

[15] Details of the geo-targeted T&D deferral analysis are included in Appendix A.

Figure 10: New DR Program Potential in 2023 (High Sensitivity Case)



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

A DR portfolio constructed from cost-effective programs in the High Sensitivity Case would produce total incremental DR potential of 484 MW in 2023. Under the illustrative assumptions in this case, the cost-effective incremental portfolio would consist of 393 MW of conventional DR programs, and 91 MW of new DR programs. The portfolio of new DR programs includes residential smart water heating[16] (24 MW) and C&I HVAC-based Auto-DR (67 MW). Achievement of all cost-effective DR potential under the High Sensitivity Case would amount to total system-wide DR capability of 1,334 MW.

[16] Smart water heating has lower cost-effective potential in 2023 than timed water heating. However, the smart water heating program provides more value and more significant per-participant impacts as participation ramps up in the later years of the study horizon, so it is the water heating program that was included in the portfolio.

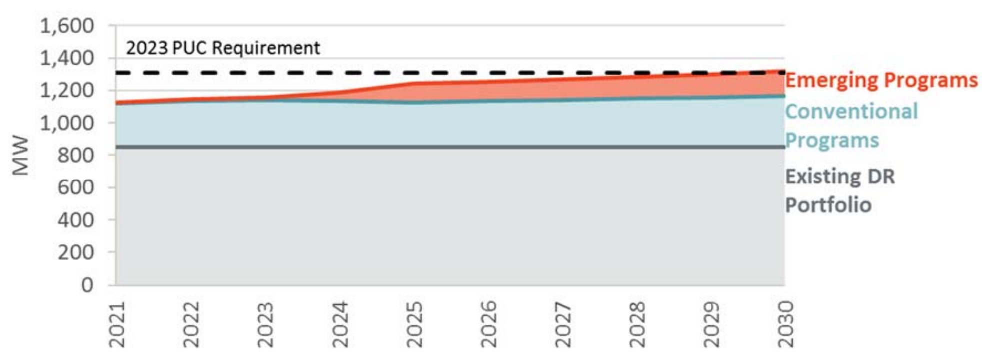
V. Expanded DR Potential in 2030

Base Case

Opportunities to expand cost-effective DR portfolio will grow beyond 2023. Most significantly, time-varying rates (such as TOU and CPP rates) can be offered to customers following completion of the AMI rollout in 2024. Additionally, the customer base is projected to grow over the study horizon, expanding the population of customers eligible to participation in DR programs. Growth in the market penetration of renewable generation will likely lead to more volatility in energy costs, further creating opportunities for DR to provide value. Additionally, current participants in the Savers Switch program are expected to transition to the smart thermostat-based A/C Reward program over time. Smart thermostats provide a greater per-participant demand reduction than the technology in the Savers Switch program, therefore further increasing DR potential.

Figure 11 summarizes growth in DR potential under Base Case assumptions for the portfolio of cost-effective DR programs. The majority of the post-2023 growth comes from the introduction of time-varying pricing programs.

Figure 11: Cost-Effective DR Potential, Base Case



Under Base Case conditions, benefits of the DR program are primarily driven by avoided generation capacity costs. Avoided generation capacity costs account for $51 million of the $66 million (77 percent) in total annual benefits from the DR programs in the year 2030. This is because the relatively low avoided costs in the Base Case scenario tend to favor conventional DR programs which are primarily constrained to reducing the system peak, but have lower costs as a result of this somewhat limited functionality. Table 4 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the Base Case.

Table 4: Annual Avoided Costs from 2030 DR Portfolio, Base Case ($ million/year)

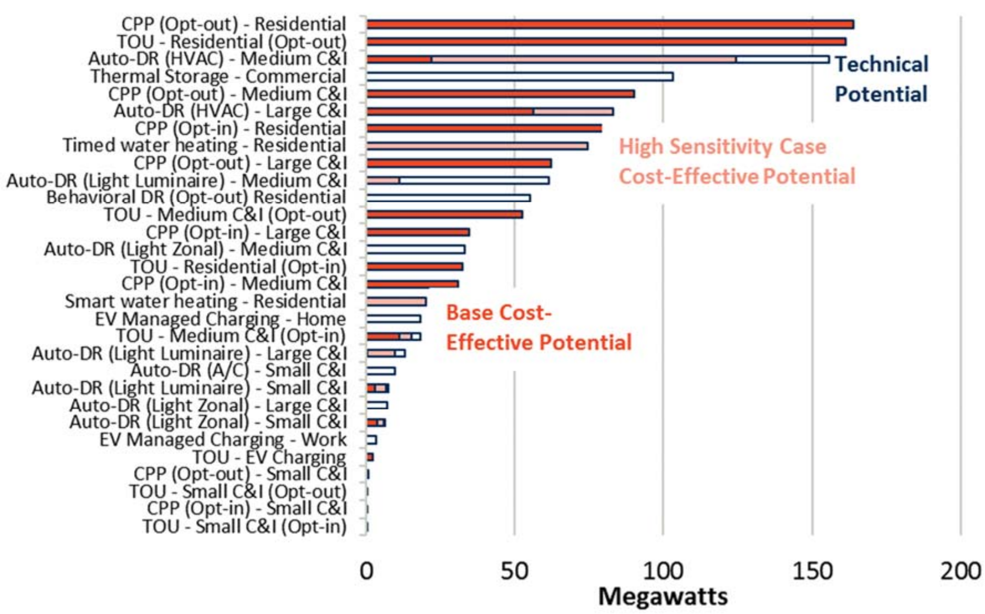
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

Notes: Benefits shown in 2023 dollars.

High Sensitivity Case

Drivers of growth over time under the illustrative High Sensitivity Case conditions are similar to growth drivers under Base Case conditions, with AMI-enabled time-varying rates accounting for the majority of new opportunities after 2023. Figure 12 summarizes the 2030 incremental measure-level potential for both the Base Case and the High Sensitivity Case.

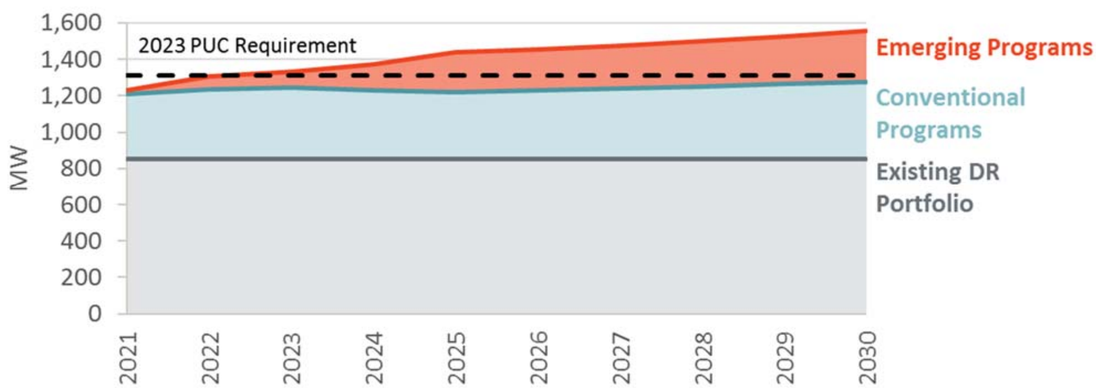
Figure 12: New DR Program Potential in 2030



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The capability of the cost-effective DR portfolio for the High Sensitivity Case is summarized in Figure 13.

Figure 13: Cost-Effective DR Potential, High Sensitivity Case



Over the longer-term, new policies could potentially drive down DR costs and therefore increase cost-effective potential. One initiative that has garnered some attention is the development of a technology standard known as "CTA-2045." CTA-2045 is a communications interface which would allow various control technologies to connect to appliances through a standard port or socket. While widespread adoption of this standard is not considered to be imminent, it could potentially have positive implications for DR adoption in the longer term. See the Sidebar at the end of this section for further discussion of the outlook for CTA-2045.

The benefits of DR under the High Sensitivity Case assumptions continue to be driven primarily by avoided generation capacity costs. However, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Table 5 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the High Sensitivity Case.

Table 5: Annual Avoided Costs from 2030 DR Portfolio, High Sensitivity Case ($ million/year)

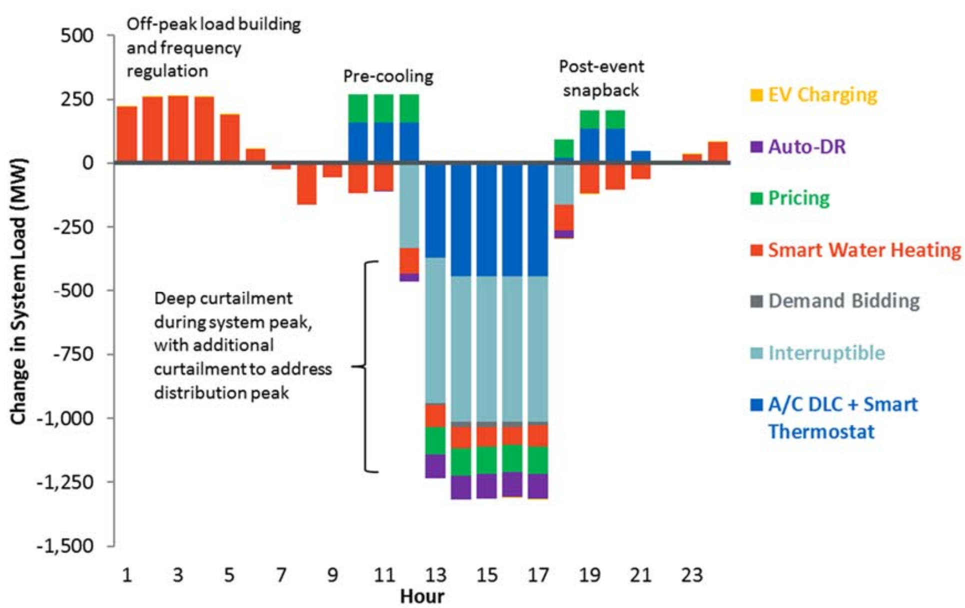
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

Notes: Benefits shown in 2023 dollars.

DR Portfolio Operation

The addition of emerging programs to NSP's DR portfolio will improve operational flexibility across NSP's system. Figure 14 illustrates how the cost-effective DR portfolio from the High Sensitivity Case could operate on an hourly basis during the days of the year with the highest system peak demand. The profile shown maximizes avoided costs relative to the system cost assumptions used in this study.

Figure 14: Average Load Impacts of the 2030 Cost-Effective DR Portfolio on Top 10 Load Days (High Sensitivity Case)



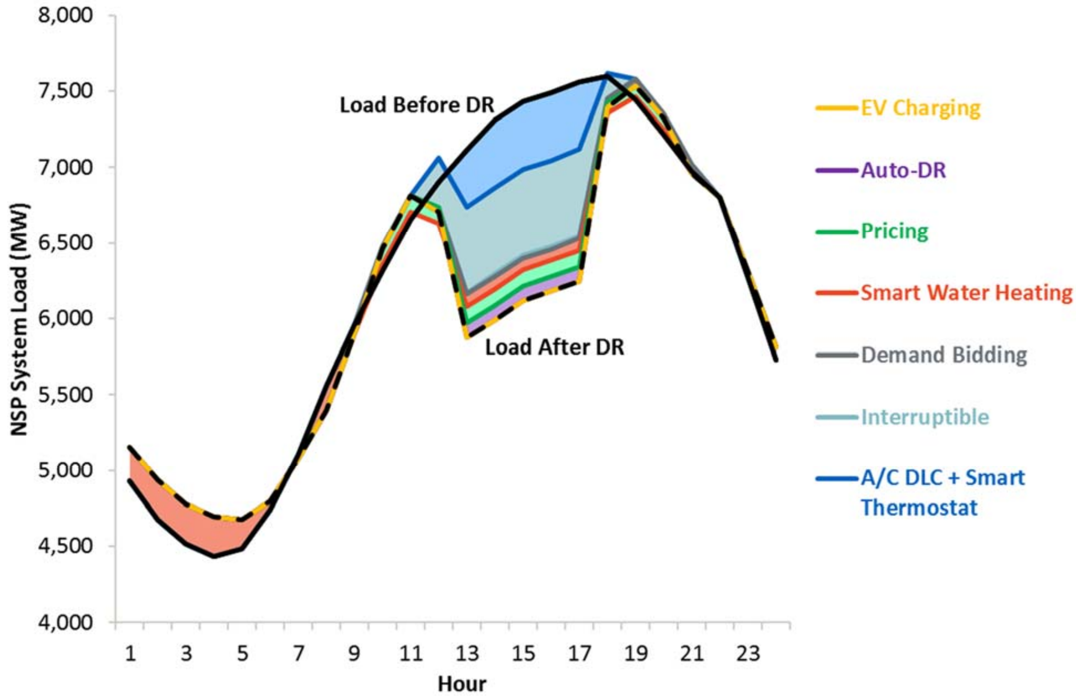
Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

A deep curtailment of load during system peak hours is utilized to capture significant generation and T&D capacity deferral benefits. These also tend to be hours when energy costs are highest, leading to additional energy value. The duration of the peak load curtailment spans a fairly broad period of time – seven hours – in order to account for the lack of coincidence of the system and local peak demand that drive capacity needs. Load curtailment can be staggered across DR programs – and across participants in a given DR program – in order to achieve this duration of demand reduction.

Load increases are observed immediately before and after the peak load reduction. This is driven mostly by the need to maintain and restore building temperatures to desired levels around DR events. The smart water heating program builds load during nighttime hours, shifting heating load to the lowest cost hours and potentially reducing the curtailment of renewable generation.

Figure 15 illustrates how NSP's system load shape changes as a result of the impacts shown in Figure 14 above. The figure shows a steep reduction in load during hours of the MISO system peak, while NSP's later peak is only modestly reduced. This is primarily due to NSP's planning needs being driven by MISO coincident peak demand. If the MISO peak shifts later in the day due to solar PV adoption, or if NSP transitions to an increased focus on its own peak demand in planning activities, then the dispatch of the DR programs would need to be modified accordingly. In particular, it may become necessary to stagger the utilization of DR programs across a broader window of hours in order to "flatten" peak demand across the hours of the day.

Figure 15: Average Impacts of the 2030 Cost-Effective DR Portfolio on NSP System Load (High Sensitivity Case)



Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

Sidebar: The Outlook for CTA-2045

CTA-2045 is a standard which specifies a low-cost communications "socket" that would be embedded in electric appliances and other consumer products. If consumers wished to make an appliance capable of participating in a demand response program, they could simply plug a communications receiver into the socket, thus allowing the appliance to be controlled by themselves or a third party. CTA-2045 has the potential to establish a low-cost option for two-way communications capability in appliances, thus reducing the cost and hassle of consumer enrollment in DR programs that would otherwise require on-site installation of more costly equipment.

Development of CTA-2045 began in 2011, through work by the Consumer Technology Association (CTA) and the Electric Power Research Institute (EPRI). Refinements to the standard are ongoing. To assess the outlook for CTA-2045 and its potential implications for future DR efforts, we conducted phone and email interviews with subject matter experts from utilities, appliance manufacturers, and DR software platforms.

There is a shared view that CTA-2045 is facing a chicken-and-egg problem. Manufacturers have been hesitant to incorporate the standard into their products, because there is a cost associated with doing so and they have not yet observed demand in the market for the communications functionality. At the same time, a barrier preventing increased adoption of DR technologies could be some of the costs and installation challenges that CTA-2045 would ultimately address.

Products with CTA-2045 functionality have not yet been deployed at scale, and where available are sold at a price premium that is significantly higher than the unit costs that could ultimately be achieved at scale. The relative lack of enthusiasm among manufacturers for rolling out CTA-2045 compliant products has led to a slow pace of development of the standard itself. Progress is being made incrementally, though technical issues still remain to be resolved.

Looking forward, some in the industry feel that the mandating CTA-2045 through a new state appliance standard could be the catalyst that is needed for adoption to become broadly widespread. Aggressive support for CTA-2045 by large utilities is also considered to be the type of activity that would facilitate adoption.

If compliance with CTA-2045 ultimately were to accelerate through activities like those described above, electric water heaters are poised to become the first such commercial application, as they have been the most common test case for proving the technical concept and are an attractive source of load flexibility. Particularly in the context of water heaters, CTA-2045 would help to overcome the challenge of enrolling customers in a DR program during the very narrow window of time during which their existing water heater expires and must be replaced. Other controllable end-uses, such as thermostats or even electric vehicle chargers could be candidates for the standard, though these technologies sometimes already come pre-equipped with communications capabilities.

VI. Conclusions and Recommendations

NSP's sizeable existing DR portfolio has the potential to be expanded by tapping into latent demand for existing programs and also by rolling out a new portfolio of emerging DR programs. Specific recommendations for acting on the findings of this study including the following:

Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program. NSP's relatively low avoided costs mean that lower cost, established DR programs are the most economically attractive options in the near term. Smart thermostats and a Medium C&I interruptible program present the largest incremental opportunity and the least amount of uncertainty/risk.

Pilot and deploy a smart water heating program. There is significant experience with advanced water heating load control in the Upper Midwest, and the technology is rapidly advancing. The thermal storage capabilities of water heaters provide a high degree of load flexibility that can be adapted to a range of system needs.

As a complementary activity to the development of a smart water heating program, also evaluate the economics and environmental impacts of switching from gas to electric heating, factoring in the grid reliability benefits associated with this flexible source of load. Doing so would require revisiting existing state policies that prohibit utility-incentivized fuel switching.

Build the foundation for a robust offering of time-varying rates. As a first step, prepare a strategy for rolling out innovative rates soon after AMI is deployed. This should include exploring rate offerings that could be deployed to customers on a default (opt-out) basis, as default rate offerings maximize the overall economic benefit for the program.

Develop measurement & verification (M&V) 2.0 protocols to ensure that the impacts of the program are dependable and can be integrated meaningfully into resource planning efforts. Included in this initiative could be the development of a data collection plan to enhance the quality of future market potential studies. Further, detailed customer segmentation and geographically granular load data at the distribution system level will provide an improved base from which to develop a cost-effective DR strategy.

Design programs with peak period flexibility. From a planning standpoint, the timing of the peak period could change for a variety of reasons (e.g., DR flattens the peak, solar PV shifts the net peak, or the planning emphasis shifts from a focus on the MISO peak to a focus on more local peaks). DR programs will need to be designed with the flexibility to adjust the timing of curtailments in response to these changes.

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Appendix A: Load*Flex* Modeling Methodology and Assumptions

The Load*Flex* Model

The Brattle Group's Load*Flex* model was developed to quantify the potential impacts, costs, and benefits of demand response (DR) programs. The Load*Flex* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging "DR 2.0" programs which not only reduce system peak demand, but also provide around-the-clock load management opportunities.

The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to the utility's experience with DR programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).

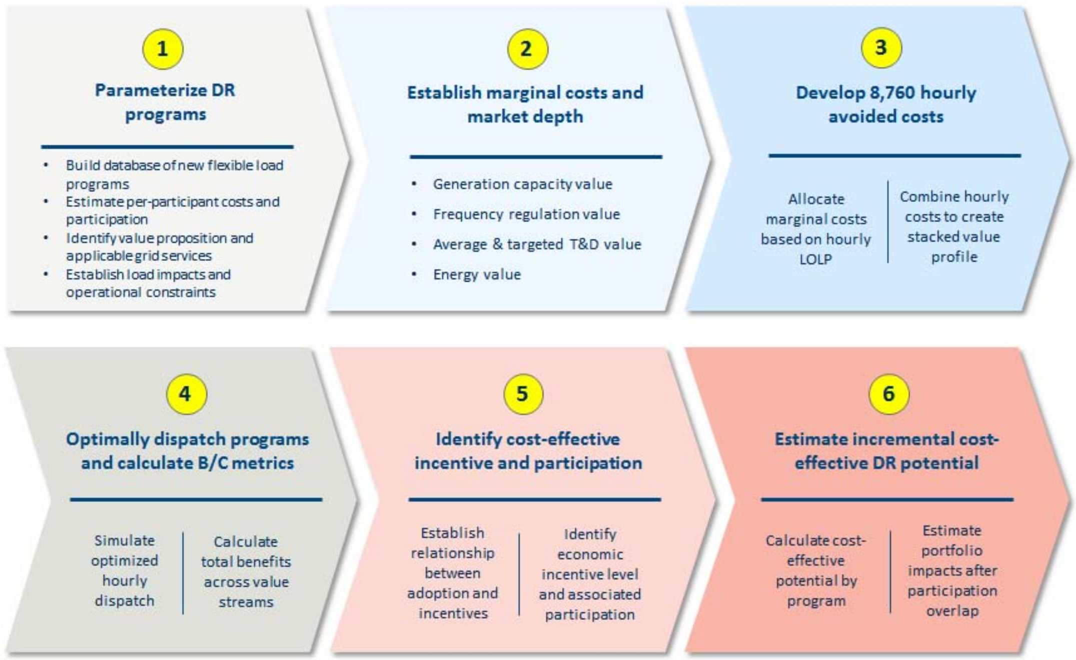
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of the utility's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* methodology is organized around six steps, as summarized in Figure 16. The remainder of this appendix describes each of the six steps in further detail, documenting methodology, assumptions, and data sources.

Figure 16: The Load*Flex* Modeling Framework



Step 1: Parameterize the DR programs

Each DR program is represented according to two broad categories of characteristics: Performance characteristics and cost characteristics.

Program Performance Characteristics

The performance characteristics of each DR program are represented in detail in Load*Flex* to accurately estimate the ability of the DR programs to provide system value. The following are key aspects of each program's performance capability.

Load impact profiles

Each DR program is represented with 24-hour average daily profiles of load reduction and load increase capability. These 24-hour impact profiles are differentiated by season (summer, winter, shoulder) and day type (weekday, weekend). For instance, air-conditioning load curtailment capability is highest during daytime hours in the summer, lower during nighttime summer hours, and non-existent during all hours in the winter.

Whenever possible, load impacts are derived directly from NSP's experience with its existing DR programs and pilots. NSP's experience directly informed the impact estimates for direct load control, smart thermostat, and interruptible rates programs. For emerging non-pricing DR programs, impacts are based on a review of experience and studies in other jurisdictions and tailored to NSP's customer mix and climate. Methods used to develop impact profile estimates for emerging non-pricing DR programs include the following:

- *C&I Auto-DR:* The potential for C&I customers to provide around-the-clock load flexibility was primarily derived from data supporting a 2017 statewide assessment of DR potential in California[17], a 2013 LBNL study of DR capability[18], and electricity load patterns representative of C&I buildings in Minneapolis developed by the Department of Energy.[19] Customer segment-specific estimates from these studies were combined to produce a composite load impact profile for the NSP service territory based on assumptions about NSP's mix of C&I customers. Impacts were scaled as necessary for consistency with NSP's prior experience with C&I DR programs.

- *Water heating load control:* Assumptions for the water heating load control programs – both grid interactive water heating and static timed water heating - are derived from a 2016 study on the value of various water heating load control strategies.[20] The program definition assumes that only customers with existing electric resistance water heaters will be eligible for participating in the water heating programs.

- *Behavioral DR:* Impacts are derived from a review of the findings of behavioral DR pilot studies conducted around the US, including for Baltimore Gas & Electric, Consumers Energy, Green Mountain Power, Glendale Water and Power, Portland Gas Electric, and Pacific Gas and Electric. Most behavioral DR pilot studies have been conducted by Oracle (OPower) and have generally found that programs with a limited number of short curtailment events (4-10 events for 3-5 afternoon/evening hours) can achieve 2% to 3% load reduction across enrolled customers.[21] Based on these findings, we assumed that a

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17 Peter Alstone et al., Lawrence Berkeley National Laboratory, "Final Report on Phase 2 Results: 2025 California Demand Response Potential Study." March 2017.

18 Daniel J. Olsen, Nance Matson, Michael D. Sohn, Cody Rose, Junqiao Dudley, Sasank Goli, and Sila Kiliccote (Lawrence Berkeley National Oaboratory), Marissa Hummon, David Palchak, Paul Denholm, and Jennie Jorgenson (National Renewable Energy Laboratory), and Ookie Ma (U.S. Department of Energy), "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.

19 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

20 Ryan Hledik, Judy Chang, and Roger Lueken. "The Hidden Battery: Opportunities in Electric Water Heating." January 2016. Posted at: http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

21 For example, see Jonathan Cook et al., "Behavioral Demand Response Study – Load Impact Evaluation Report", January 11, 2016, prepared for Pacific Gas & Electric Company, available at: http://www.oracle.com/us/industries/utilities/behavioral-demand-response-3628982.pdf, and OPower,

Continued on next page

behavioral DR program called 10 times per year between 3 pm and 6 pm would achieve a 2.5% load reduction.

- *EV managed charging:* Estimates of load curtailment capability are based on projections of aggregate EV charging load shapes provided by Xcel Energy. The ability to curtail this charging load is based on a review of recent utility EV charging DR pilots, including managed charging programs at several California utilities (PG&E, SDG&E, SCE, and SMUD) and United Energy in Australia.[22]

- *Ice-based thermal energy storage:* Estimates of load curtailment capability are estimated based on charging and discharging (freezing and cooling) information from Ice Bear[23] and adapted to mirror building use patterns in Minnesota based on load profiles from the U.S. Department of Energy.[24]

For impacts from pricing programs, we relied on Brattle's database of time-varying pricing offerings. The database includes the results of more than 300 experimental and non-experimental pricing treatments across over 60 pilot programs.[25] It includes published results from Xcel Energy's various pricing pilots during this time period. The results of the pilots in the database are used to establish a relationship between the peak-to-off-peak price ratio of the rates and the average load reduction per participant, in order to simulate price response associated with any given rate design. This relationship between load reduction and price ratio is illustrated in Figure 17.

Continued from previous page

"Transform Every Customer into a Demand Response Resource: How Utilities Can Unlock the Full Potential of Residential Demand Response", 2014, available at: https://go.oracle.com/LP=42838?elqCampaignId=74613.

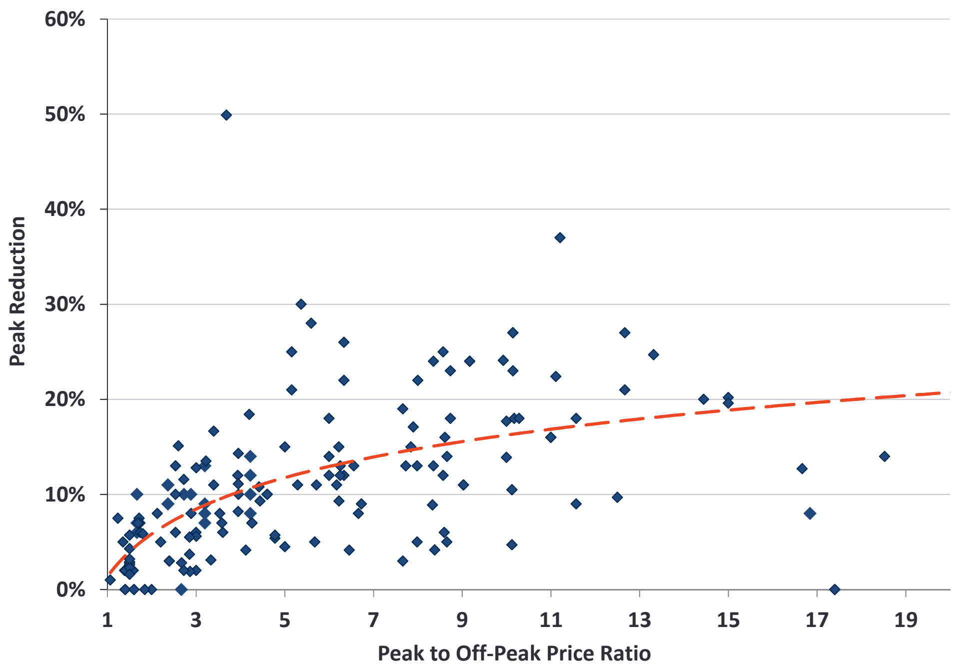
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

23 Ice Energy, "Ice Bear 20 Case Study," November 2016. Available: https://www.ice-energy.com/wp-content/uploads/2016/12/SantaYnez_CaseStudy_Nov2016.pdf

24 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

25 Ahmad Faruqui, Sanem Sergici, and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal*, 2017.

Figure 17: Relationship between Price Ratio and Price Response in Residential Pricing Pilots



Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

Daily relationship between load reduction and load increase

Some DR programs will require a load increase to offset or partially offset the load that is reduced during a curtailment event. In Load*Flex*, each program definition includes a parameter that represents the percent of curtailed load that must be offset by increased load on the same day, including the timing of when the load increase must occur. For instance, in a water heating load control program, any reduction in water heating load is assumed to be offset by an equal increase in water heating load on the same day in order to meet the customer's water heating needs. Alternatively, a reduction in air-conditioning load may only be offset partially by an increase in consumption, but it would immediately follow the curtailment.

Where data is available, these load building assumptions are based on the same data sources described above. Otherwise, these impacts are derived from assumptions that were developed for FERC's 2009 *A National Assessment of Demand Response Potential*.

Tariff-related operational constraints

Most DR programs will have administrator-defined limits on the operation of the program. This includes the maximum number of hours per day that the program can be curtailed, whether or not those curtailment hours must be contiguous, and the maximum number of days per year with allowed curtailment. Assumed operational constraints are based on Xcel Energy's program definitions and a review of common limitations from programs offered in other jurisdictions.

Ancillary services availability

If a DR program has the advanced control and communications technology necessary to provide ancillary services, Load*Flex* accounts for the capacity that is available to provide fast-response load increases or decreases in response to real-time fluctuations in supply and demand. In this study, smart water heating and Auto-DR are assumed to be able to offer ancillary services. Specifically, we model frequency regulation as it is the most valuable ancillary services product. Capability is based on the same data sources described above.

Table 6 summarizes the performance characteristics for each DR program in this study. In the table, "load shifting capability" identifies whether or not a program is capable of shifting energy usage from peak periods to off-peak periods on a daily basis.

Table 6: DR Program Performance Characteristics

Segment	Program	Peak-coincident curtailment capability (kW/participant)	Hours of Curtailment (hours)	Average regulation up provided (kW/participant)	Average regulation down provided (kW/participant)	Load shifting capability?
Residential	A/C DLC - SFH	0.62	75	0.00	0.00	No
Residential	Behavioral DR (Opt-out)	0.06	40	0.00	0.00	No
Residential	CPP (Opt-in)	0.34	75	0.00	0.00	No
Residential	CPP (Opt-out)	0.17	75	0.00	0.00	No
Residential	EV Managed Charging - Home	0.46	45	0.00	0.00	Yes
Residential	EV Managed Charging - Work	0.09	45	0.00	0.00	Yes
Residential	Smart thermostat - MDU	0.86	75	0.00	0.00	No
Residential	Smart thermostat - SFH	1.15	75	0.00	0.00	No
Residential	Smart water heating	0.46	4,745	0.37	0.38	Yes
Residential	Timed water heating	0.43	1,825	0.00	0.00	Yes
Residential	TOU - EV Charging (Opt-in)	0.05	1,460	0.00	0.00	Yes
Residential	TOU (Opt-in)	0.17	1,284	0.00	0.00	No
Residential	TOU (Opt-out)	0.08	1,284	0.00	0.00	No
Small C&I	A/C DLC	1.93	75	0.00	0.00	No
Small C&I	Auto-DR (A/C)	1.37	200	0.37	0.49	Yes
Small C&I	Auto-DR (Light Luminaire)	1.07	300	0.52	0.57	Yes
Small C&I	Auto-DR (Light Zonal)	0.92	300	0.44	0.49	Yes
Small C&I	CPP (Opt-in)	0.02	75	0.00	0.00	No
Small C&I	CPP (Opt-out)	0.01	75	0.00	0.00	No
Small C&I	Demand Bidding	0.02	200	0.00	0.00	No
Small C&I	Interruptible	1.98	90	0.00	0.00	No
Small C&I	TOU (Opt-in)	0.01	1,281	0.00	0.00	No
Small C&I	TOU (Opt-out)	0.00	1,281	0.00	0.00	No
Medium C&I	A/C DLC	3.92	75	0.00	0.00	No
Medium C&I	Auto-DR (HVAC)	46.17	430	14.61	14.09	Yes
Medium C&I	Auto-DR (Light Luminaire)	18.22	300	8.62	8.83	Yes
Medium C&I	Auto-DR (Light Zonal)	9.81	300	5.47	5.78	Yes
Medium C&I	CPP (Opt-in)	4.83	75	0.00	0.00	No
Medium C&I	CPP (Opt-out)	2.42	75	0.00	0.00	No
Medium C&I	Demand Bidding	4.43	200	0.00	0.00	No
Medium C&I	Interruptible	27.45	90	0.00	0.00	No
Medium C&I	Thermal Storage	50.97	644	0.00	0.00	Yes
Medium C&I	TOU (Opt-in)	2.31	1,281	0.00	0.00	No
Medium C&I	TOU (Opt-out)	1.39	1,281	0.00	0.00	No
Large C&I	Auto-DR (HVAC)	592.09	430	151.57	207.60	Yes
Large C&I	Auto-DR (Light Luminaire)	416.95	120	191.67	200.74	Yes
Large C&I	Auto-DR (Light Zonal)	224.51	120	103.21	108.09	Yes
Large C&I	CPP (Opt-in)	283.92	75	0.00	0.00	No
Large C&I	CPP (Opt-out)	141.67	75	0.00	0.00	No
Large C&I	Demand Bidding	260.28	200	0.00	0.00	No
Large C&I	Interruptible	483.62	90	0.00	0.00	No

Notes:
Program impacts shown reflect impacts for new participants. Impacts shown assume each program is offered independently.

Program Cost Characteristics

The costs of each program include startup costs, marketing and customer recruitment, the utility's share of equipment and installation costs, program administration and overhead, churn costs (i.e., the annual cost of replacing participants that leave the program), and participation incentives.[26]

[26] The Utility Cost Test (UCT) is the cost-effectiveness screen used in this study, which calls for including incentive payments as a cost.

Cost assumptions are based on NSP's current program costs, where applicable. Otherwise, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors, and are tailored for consistency with NSP's current program costs. Notable assumptions in developing the cost estimates include the following:

- Water heating technology costs include the cost of the load control and communications equipment and the *incremental* cost of replacing the existing water heater (50-gallon average) with a larger water heater (80-gallon) when the existing water heater expires. The full cost of a new water heater is not assigned to the program.

- Similarly, EV charging load control equipment costs include the incremental cost of load control and communications technology, but not the full cost of a charging unit.

- The cost of AMI is not counted against any of the DR programs, as it is treated as a sunk cost that is likely to be justified by a broad range of benefits that the new digital infrastructure will provides to customers and to NSP. However, a rough estimate of the cost of IT and billing system upgrades specifically associated with offering time-varying pricing programs are included in the costs for those programs.

- The cost of advanced lighting control systems is not counted against DR programs as these control systems are typically installed for non-energy benefits.

Table 7 summarizes Base Case cost assumptions for 2023 and Table 8 summarizes High Sensitivity Case cost assumptions for 2030. The 2030 assumptions reflect an assumed 25% reduction in the cost (in real terms) of emerging technologies. Costs in both tables are shown in nominal dollars. As discussed later in this appendix, the "base" incentive levels are derived from commonly observed payments both by NSP and in other jurisdictions. They do not reflect the cost-effective incentive payment levels that are ultimately established through the modeling.

Table 7: 2023 Base Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/participant-year)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$172	$92	$0	$13	$59	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$4	$0	15
Residential	CPP (Opt-in)	$223,208	$0	$80	$83,703	$2	$0	15
Residential	CPP (Opt-out)	$223,208	$0	$40	$83,703	$2	$0	15
Residential	EV Managed Charging - Home	$0	$229	$0	$0	$17	$45	15
Residential	EV Managed Charging - Work	$0	$229	$0	$0	$17	$45	15
Residential	Smart thermostat - MDU	$0	$126	$92	$0	$11	$28	10
Residential	Smart thermostat - SFH	$0	$126	$92	$0	$11	$28	10
Residential	Smart water heating	$0	$686	$34	$0	$0	$28	10
Residential	Timed water heating	$0	$458	$34	$0	$0	$11	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$83,703	$0	$0	15
Residential	TOU (Opt-in)	$223,208	$0	$57	$83,703	$1	$0	15
Residential	TOU (Opt-out)	$223,208	$0	$29	$83,703	$0	$0	15
Small C&I	A/C DLC	$0	$172	$92	$0	$13	$237	15
Small C&I	Auto-DR (A/C)	$0	$0	$2,218	$0	$22	$112	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,328	$0	$22	$112	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$1,001	$0	$22	$112	15
Small C&I	CPP (Opt-in)	$74,403	$0	$80	$27,901	$0	$0	15
Small C&I	CPP (Opt-out)	$74,403	$0	$40	$27,901	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$691,944	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$280,126	$0	$259	15
Small C&I	TOU (Opt-in)	$74,403	$0	$57	$20,926	$0	$0	15
Small C&I	TOU (Opt-out)	$74,403	$0	$29	$20,926	$0	$0	15
Medium C&I	A/C DLC	$0	$343	$92	$0	$13	$481	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$26,820	$0	$22	$9,444	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$33,220	$0	$22	$4,351	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$24,719	$0	$22	$4,351	15
Medium C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Medium C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$280,126	$0	$249	15
Medium C&I	Interruptible	$0	$0	$0	$280,126	$0	$5,627	15
Medium C&I	Thermal Storage	$0	$120,114	$34	$0	$382	$0	20
Medium C&I	TOU (Opt-in)	$74,403	$0	$1,144	$20,926	$22	$0	15
Medium C&I	TOU (Opt-out)	$74,403	$0	$572	$20,926	$22	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$306,980	$0	$22	$108,307	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$495,047	$0	$22	$86,691	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$367,510	$0	$22	$86,691	15
Large C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Large C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$315,839	$0	$14,651	15
Large C&I	Interruptible	$0	$0	$0	$315,839	$0	$90,997	15

Notes:

All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Table 8: 2030 High Sensitivity Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/part.-yr)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$140	$75	$0	$16	$69	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$5	$0	15
Residential	CPP (Opt-in)	$182,204	$0	$65	$97,609	$2	$0	15
Residential	CPP (Opt-out)	$182,204	$0	$33	$97,609	$2	$0	15
Residential	EV Managed Charging - Home	$0	$187	$0	$0	$20	$52	15
Residential	EV Managed Charging - Work	$0	$187	$0	$0	$20	$52	15
Residential	Smart thermostat - MDU	$0	$103	$75	$0	$13	$33	10
Residential	Smart thermostat - SFH	$0	$103	$75	$0	$13	$33	10
Residential	Smart water heating	$0	$560	$28	$0	$0	$33	10
Residential	Timed water heating	$0	$374	$28	$0	$0	$13	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$97,609	$0	$0	15
Residential	TOU (Opt-in)	$182,204	$0	$47	$97,609	$1	$0	15
Residential	TOU (Opt-out)	$182,204	$0	$23	$97,609	$1	$0	15
Small C&I	A/C DLC	$0	$140	$75	$0	$16	$277	15
Small C&I	Auto-DR (A/C)	$0	$0	$1,810	$0	$26	$130	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,084	$0	$26	$130	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$817	$0	$26	$130	15
Small C&I	CPP (Opt-in)	$60,735	$0	$65	$32,536	$0	$0	15
Small C&I	CPP (Opt-out)	$60,735	$0	$33	$32,536	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$806,905	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$326,666	$0	$302	15
Small C&I	TOU (Opt-in)	$60,735	$0	$47	$24,402	$0	$0	15
Small C&I	TOU (Opt-out)	$60,735	$0	$23	$24,402	$0	$0	15
Medium C&I	A/C DLC	$0	$280	$75	$0	$16	$561	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$21,893	$0	$26	$11,013	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$27,117	$0	$26	$5,074	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$20,178	$0	$26	$5,074	15
Medium C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Medium C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$326,666	$0	$291	15
Medium C&I	Interruptible	$0	$0	$0	$326,666	$0	$6,562	15
Medium C&I	Thermal Storage	$0	$98,049	$28	$0	$445	$0	20
Medium C&I	TOU (Opt-in)	$60,735	$0	$934	$24,402	$26	$0	15
Medium C&I	TOU (Opt-out)	$60,735	$0	$467	$24,402	$26	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$250,588	$0	$26	$126,301	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$404,107	$0	$26	$101,093	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$299,998	$0	$26	$101,093	15
Large C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Large C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$368,313	$0	$17,085	15
Large C&I	Interruptible	$0	$0	$0	$368,313	$0	$106,116	15

Notes:
2030 one-time costs assumed to be 30% lower than 2023 one-time costs (in real terms), reflecting assumed declines in technology costs. All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Step 2: Establish system marginal costs and quantity of system need

Load*Flex* was used to quantify a broad range of value streams that could be provided by DR. These include avoided generation capacity costs, avoided system-wide T&D costs, additional avoided distribution costs from geo-targeted deployment of the DR programs, frequency regulation, and net avoided marginal energy costs.

The system costs that could be avoided through DR deployment are estimated based on market data that is specific to NSP's service territory. Assumptions used in developing each marginal (i.e., avoidable) cost estimate are described in more detail below, for both the Base Case and the High Sensitivity Case.

Avoided generation capacity costs

DR programs are most appropriately recognized as substitutes for new combustion turbine (CT) capacity. CTs are "peaking" units with relatively low up-front installation costs and high variable costs. As a result, they typically only run up to a few hundred hours of the year, when electricity demand is very high and/or there are system reliability concerns. Similarly, use of DR programs in the U.S. is typically limited to less than 100 hours per year. This constraint is either written into the DR program tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs.

In contrast, new intermediate or baseload capacity (e.g., gas-fired combined cycle) has a higher capital cost and lower variable cost than a CT, and therefore could run for thousands of hours per year. The DR programs considered in this study cannot feasibly avoid the need for new intermediate or baseload capacity, because they cannot be called during a sufficient number of hours of the year. Energy efficiency is a more comparable demand-side alternative to these resource types since it is a permanent load reduction that applies to a much broader range of hours.

In the Base Case, the installed cost of new CT capacity is based on data provided directly by NSP and consistent with the assumptions in NSP's 2019 IRP for a brownfield CT. The total cost amounts to $60.60/kW-year; this is sometimes referred to the gross cost of new entry (CONE). The gross CONE value is adjusted downward to account for the energy and ancillary services value that would otherwise be provided by that unit. Based on simulated unit profit data provided by NSP, we have estimated the annual energy and ancillary services value to be roughly $5.50/kW-year. The resulting net CONE value is $55.20/kW-year. This calculation is described further in Table 9 below.

This same approach is used to establish the capacity cost for the High Sensitivity Case. Rather than using the CT cost from NSP's IRP, we relied on the U.S. Energy Information Administration's (EIA's) estimate of the installed cost of an Advanced CT from the 2018 Annual Energy Outlook. For the Midwest Reliability Organization West region, this amounts to a gross CONE of $76.80/kW-year. Reducing this value by the same energy and ancillary services value described above leads to a net CONE of $71.40/kW-year.

Table 9: Combustion Turbine Cost of New Entry Calculation

Variable		NSP 2019 IRP Brownfield CT	NSP 2019 IRP Greenfield CT	AEO 2018 Advanced CT
Overnight Capital Cost ($/kW)	[1]	$467	$617	$698
Effective Charge Rate (%)	[2]	10%	10%	10%
Levelized Capital Cost ($/kW-yr)	[3]=[1]x[2]	$46.7	$61.7	$69.8
Annual Fixed Costs ($/kW-yr)	[4]	$13.9	$13.9	$7.0
Gross Cost of New Entry ($/kW-yr)	[5]=[3]+[4]	$60.6	$75.6	$76.8
E&AS Margins ($/kW-yr)	[6]	$5.5	$5.5	$5.5
Net Cost of New Entry ($/kW-yr)	[7]=[5]-[6]	$55.2	$70.2	$71.4

Notes: All costs shown in 2018 dollars. Assumes that overnight capital costs are recovered at 10% effective charge rate. AEO 2018 advanced CT costs shown for the Midwest Reliability Organization West region. Capacity costs are held constant in real terms throughout the period of study.

DR produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of 8% percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise.[27] When estimating the avoided capacity cost of DR, the avoided cost is grossed up to account for this factor. For this study, Xcel Energy provided load data at the generator level, thus already accounting for line loss gross-up.

Similarly, NSP incorporates a planning reserve margin of 2.4% percent into its capacity investment decisions.[28] This effectively means NSP will plan to have enough capacity available to meet its projected peak demand plus 2.4% percent of that value. In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.024 kW of capacity. Including the 2.4% reserve margin adjustment increases the net CONE value described above from $55.2 and $71.4/kW-year to $56.5 and $73.1/kW-year, for the Base and High Sensitivity Cases respectively. This is the generation capacity value that could be provided by DR if it were to operate exactly like a CT.

Avoided transmission capacity costs

Reductions in system peak demand may also reduce the need for transmission upgrades. A portion of transmission investment is driven by the need to have enough capacity available to

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27 8% represents an average line loss across NSP territories and customer segments. Actual line losses range from 2 to 10%.

28 NSP's planning reserve margin target is 7.8% of load during the MISO peak, which translates into a margin of 2.4% during its own system peak.

move electricity to where it is needed during peak times while maintaining a sufficient level of reliability. Other transmission investments will not be peak related, but rather are intended to extend the grid to remotely located sources of generation, or to address constraints during mid- or off-peak periods. Based on the findings of NSP's 2017 T&D Avoided Cost Study for energy efficiency programs, we have assumed an avoidable transmission cost of $3.10/kW-year in 2023, rising to $3.60/kW-year in 2030.[29]

Avoided system-wide distribution capacity costs

Similar to transmission value, there may be long-term distribution capacity investment avoidance value associated with reductions in peak demand across the NSP system. For programs that do not provide the higher-value distribution benefits from geo-targeted deployment, as described below, we have assumed that peak demand reductions can produce avoided distribution costs of $8.10/kW-year in 2023, rising to $9.50/kW-year in 2030, based on NSP's 2017 T&D Avoided Cost Study.

Geo-targeted distribution capacity costs

DR participants may be recruited in locations on the distribution system where load reductions would defer the need for local capacity upgrades. This local deployment of the DR program can be targeted at specifically locations where distribution upgrades are expected to be costly.

DR cannot serve as a substitute for distribution upgrades in all cases, such as adding new circuit breakers, telemetry upgrades, or adding distribution lines to connect new customers. However, in many cases, system upgrades are needed to meet anticipated gradual load growth in a local area. At times, system planners must over-size distribution investments relative to the immediate needs to meet local load to allow for future load growth or utilize equipment (such as transformers) that only comes in certain standard sizes. To the extent that DR can be used to reduce local peak loads, the loading on the distribution system is reduced, which means otherwise necessary distribution upgrades may be deferred. Such deferrals are especially valuable if load growth is relatively slow and predictable such that the upgraded system would not be fully utilized for many years.

To quantify geo-targeted distribution capacity deferral value in Load*Flex*, we began with a list of all distribution capacity projects in NSP's five-year plan. Brattle worked with NSP staff to reduce this list to a subset of projects that are likely candidates for deferral through DR. Four criteria were applied to identify the list of candidate deferral projects:

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[29] Xcel Energy, Minnesota Power, Otter Tail Power Company, Mendota Group & Environmental Economics, "Minnesota Transmission and Distribution Avoided Cost Study," July 31, 2017.

1. The need for the distribution project must be driven by load growth. DR could not be used to avoid the need to simply replace aging equipment, for example.

2. The project must have a meaningful overall cost on a per-kilowatt basis. In our analysis, we required that the cost of the project equate to a value of at least $100,000 per megawatt of reduced demand in order to be considered.[30] This is the equivalent of roughly $7/kW-year on an annualized basis. Projects below this cost threshold were excluded from the geo-targeted deferral analysis.

3. There must be sufficient local customer load in order for the upgrade to be deferrable through the use of DR. For instance, if a 20 MW load reduction would be needed to avoid a specific distribution upgrade, and there was only 25 MW of total load at that location in the system, then DR would not be a useful candidate because it is unlikely that DR could consistently and reliably produce an 80% load reduction. In establishing this criterion, projects with more than 6 MVA of "load at risk"[31] were excluded, as 6 MVA represents about half of the load on a typical feeder.

4. The project should not be needed to simultaneously address many risks across feeders. In some cases, distribution upgrades are needed to mitigate a number of different contingencies. There are significant operational challenges associated with using DR in a similar manner. Projects were screened out based on the number and severity of risks that they were intended to address.

After applying the above criteria, up to roughly 10% of the cost of NSP's 5-year plan remained as potentially deferrable through the use of DR. We have assumed linear growth in NSP's distribution capacity needs, meaning the geo-targeted distribution deferral opportunity increases by this amount every five years over the forecast horizon. Figure 17 summarizes the process for identifying geo-targeted distribution deferral opportunities.

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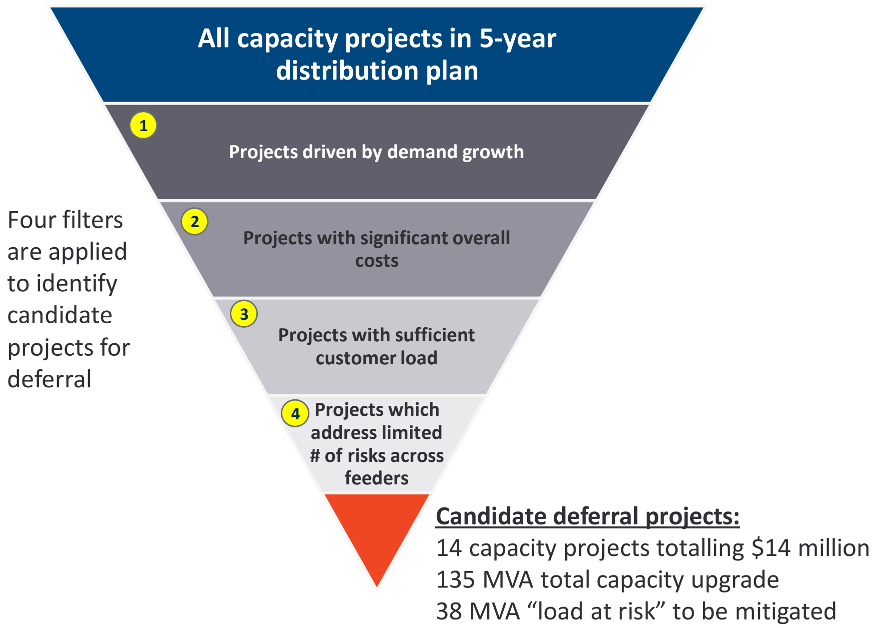
[30] For simplicity, we assumed 1 MVA = 1 MW.

[31] "Load at risk" effectively represents the load reduction that would need to be achieved to defer the capacity upgrade.

Figure 18: Identification of Candidates for Geo-targeted Distribution Investment Deferral



Avoided energy costs

Load can be shifted from hours with higher energy costs to hours with lower energy costs, thus producing net energy cost savings across the system.[32] Hourly energy costs in this study are based on the 2018 MISO Transmission Expansion Plan (MTEP18) modeled day-ahead prices for the NSP hub. These modeled prices were used to capture evolving future system conditions that would not be reflected in historical prices. MTEP18 presents four "futures" that represent broadly different long-term views of MISO energy system, enabling the evaluation of the avoided energy value of DR under different market conditions.

For the Base Case, we relied on prices from MTEP18's Continued Fleet Change (CFC) future. This future assumes a continuation of trends in the MISO market from the past decade: persistent low gas prices, limited demand growth, continued economic coal retirements, and gradual growth in renewables above state requirements.[33] Figure 19 below shows that 2022 energy prices

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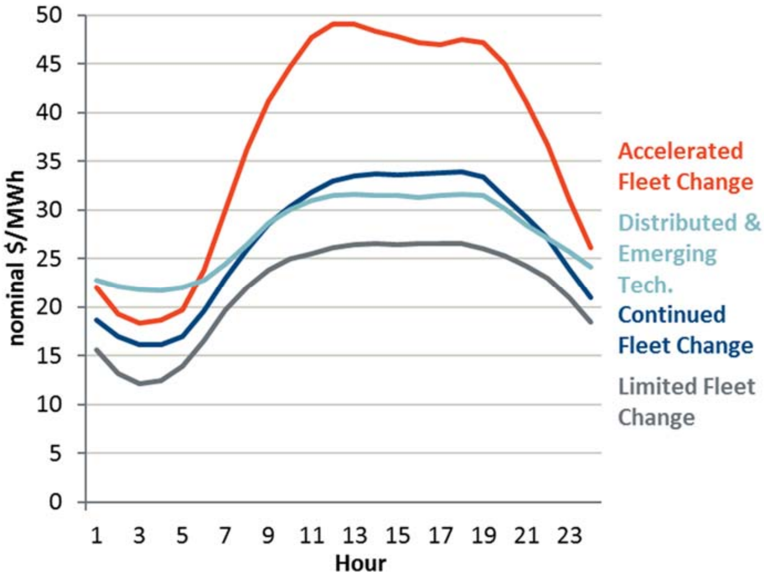
32 Energy savings refer to reduced fuel and O&M costs. In this study, we do not model the impact that DR would have on MISO wholesale energy prices. This is sometimes referred to as the demand response induced price effect (DRIPE). It represents a benefit to consumers and an offsetting cost to producers, with no net change in costs across the system as a whole.

33 See MISO, "MTEP 18 Futures – Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results." for additional details on MTEP18 scenarios.

under the CFC future lie somewhere in the middle of the four MTEP scenarios (energy prices in other years follow the same relative pattern across scenarios).

Figure 19: Average Energy Price by Hour of Day in 2022 MTEP Scenarios for NSP Hub



For the High Sensitivity Case, we relied on prices from the Accelerated Fleet Change (AFC) future. The AFC case has twice the amount of renewable generation capacity additions as the CFC future. However, increased load growth, accelerated coal retirements, and higher gas prices lead to overall higher energy prices, particularly in daytime hours. For our analysis years (2023, 2025 and 2030), we relied on prices from the nearest MTEP modeling year (2022, 2027, and 2032, respectively) and adjusted them accordingly for inflation (assumed to be 2.2% per year).

Ancillary services

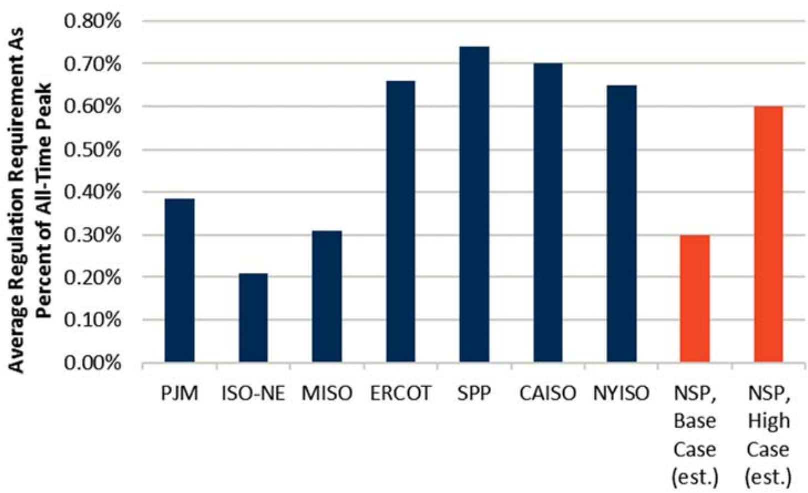
The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service.

Frequency regulation is a high value resource with a very limited need. Across most markets, the need for frequency regulation capacity is less than 1% of the system peak. We assume that the frequency regulation needs in the NSP system across all analysis years are 25 MW (0.3% of annual peak) in the Base Case, and 50 MW in the High Sensitivity Case (0.6% of annual peak).[34] Figure 20 summarizes frequency regulation needs across various U.S. markets, demonstrating

[34] Calculated assuming an annual peak of 8,335 MW after line losses.

that the quantities of frequency regulation assumed in this study are consistent with experience elsewhere.

Figure 20: Frequency Regulation Requirements Across Wholesale Markets



Sources and Notes: Values for wholesale markets extracted from PJM, "RTO/ISO Regulation Market Comparison", April 13, 2016. Orange bars for NSP assume that NSP's all-time peak is 8,335 MW at the customer level, based on three years of provided peak load data and assumed 8% line losses. Frequency regulation values for all markets are average levels as of 2016.

Because regulation prices were not available from the 2018 MTEP, we utilized 2017 hourly generation regulation prices for the MISO system adjusted for inflation.

Table 10 summarizes the potential value of each DR benefit. Values shown are the maximum achievable value. Operational constraints of the DR resources (e.g., limits on number of load curtailments per year) often result in realized benefits estimates that are lower than the values shown.

Table 10: Summary of Avoided Costs/Value Streams in 2023

Value Stream	Quantity of Need		Avoided Cost		Description
	Base Case	High Case	Base Case	High Case	
Avoided Generation Capacity	Unconstrained	Unconstrained	$63.0/kW-year	$81.5/kW-year	Base: Xcel's Brownfield CT costs minus estimated CT energy revenues from 2018 IRP, plus 2.4% reserve margin gross-up.
Avoided Transmission Capacity	Unconstrained	Unconstrained	$3.1/kW-year	$3.1/kW-year	72% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Avoided Distribution Capacity	Unconstrained	Unconstrained	$8.0/kW-year	$8.0/kW-year	28% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Geo-targeted Distribution Capacity	38 MW	38 MW	$25.8/kW-year	$25.8/kW-year	Total value of 14 projects identified as eligible for distribution capacity deferral by demand response.
Frequency Regulation	25 MW	50 MW	Avg: $12.4/MWh	Avg: $12.4/MWh	2017 MISO regulation prices. Assumes that NSP's share of regulation need is 25 MW in 2023 and 50 MW in 2030.
Avoided Energy	Unconstrained	Unconstrained	Avg: $27.5/MWh	Avg: $27.5/MWh	Hourly MISO MTEP18 modeled energy prices for NSP HUB. 2023 used prices from the CFC 2022 scenario, and 2030 used prices from the AFC 2032 scenario.
Top 10% Average			$50.5/MWh	$71.3/MWh	
Bottom 10% Average			$8.1/MWh	$8.6/MWh	

Notes:
All values shown in nominal dollars. 2030 avoided costs are similar, rising at inflation.

Step 3: Develop 8,760 hourly profile of marginal costs

Each of the annual avoided cost estimates established in Step 2 is converted into a chronological profile of hourly costs for all 8,760 hours of the year. In each hour, these estimates are added together across all value streams to establish the total "stacked" value that is obtainable through a reduction in load in that hour (or, conversely, the total cost associated with an increase in load in that hour).

Capacity costs are allocated to hours of the year proportional to the likelihood that those hours will drive the need for new capacity. In other words, the greater the risk of a capacity shortage in a given hour, the larger the share the marginal capacity cost that is allocated to that hour.

Capacity costs are allocated across the top 100 load hours of the year. The allocation is roughly proportional to each hour's share of total load in the hours. This means more capacity value is allocated to the top load hour than the 100th load hour.

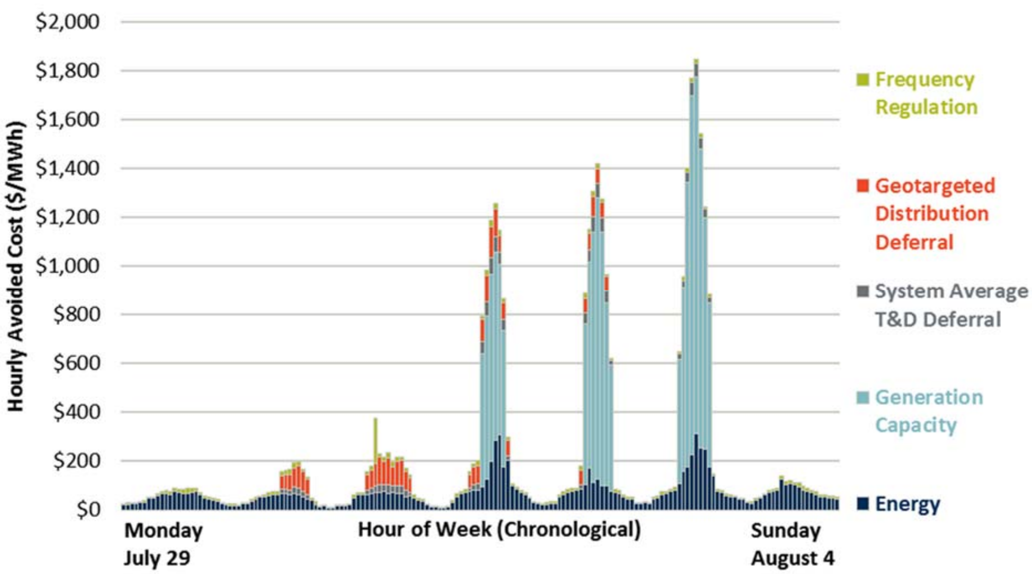
Different allocators are used to allocate generation, transmission, and distribution capacity costs. Generation and transmission capacity costs are allocated based on 2017 hourly MISO system gross load.[35] Distribution capacity costs are allocated based on hourly feeder load data provided by NSP. Both generic distribution capacity deferral and geo-targeted distribution capacity deferral value are allocated over a larger number of peak hours (roughly 330 hours, rather than 100 hours), representing that a single distribution project will address multiple feeders with load profiles that are only partially coincident.

A conceptually similar approach to quantifying capacity value is used in the California Energy Commission's time-dependent valuation (TDV) methodology for quantifying the value of energy efficiency, and also in the CPUC's demand response cost-effectiveness evaluation protocols. This hourly allocation-based approach effectively derates the value of distributed resources relative to the avoided cost of new peaking capacity by accounting for constraints that may exist on the operator's ability to predict and respond to resource adequacy needs. These constraints could result in DR utilization patterns that reflect a willingness to bypass some generation capacity value in order to provide distribution deferral value, for instance. The approach is effectively a theoretical construct intended to quantify long-term capacity value, rather than reflecting the way resource adequacy payments would be monetized by a DR operator in a wholesale market.

Figure 21 illustrates the "stacked" marginal costs associated with each value stream for a single week in the study period. The figure shows that certain hours present a significantly larger opportunity to reduce costs through load reduction – namely, those hours to which capacity costs are allocated.

35 Capacity value was allocated proportional to MISO gross load because NSP is required to use its MISO-coincident peak for resource adequacy planning decisions.

Figure 21: Chronological Allocation of Marginal Costs (Illustration for Week of July 29)



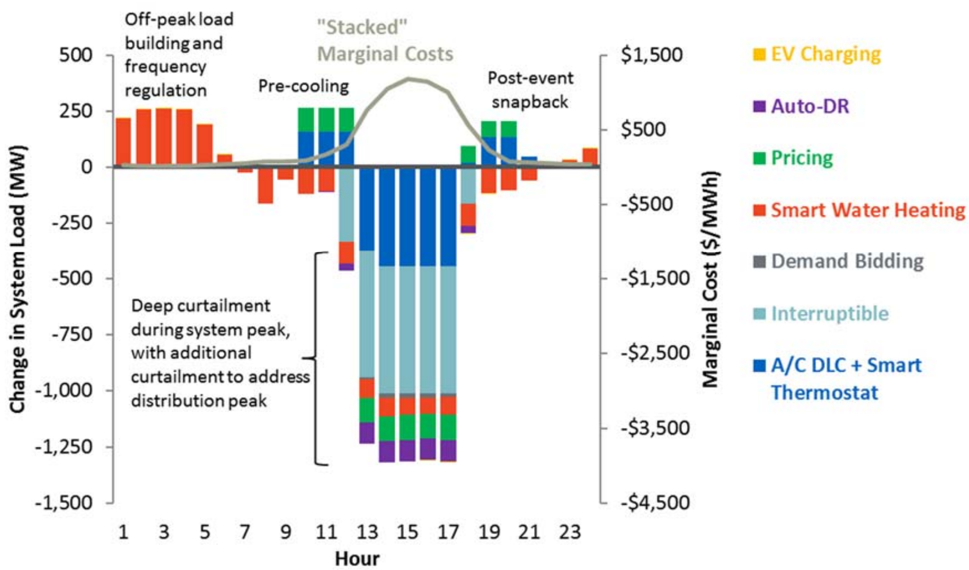
Notes: Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

Step 4: Optimally dispatch programs and calculate benefit-cost metrics

As discussed above, using DR to pursue one value stream may require forgoing opportunities to pursue other "competing" sources of value. While the value streams quantified in this study can be estimated individually, those estimates are not purely additive. A DR operator must choose how to operate the program in order to maximize its value. Accurately estimating the total value of DR programs requires accounting for tradeoffs across the value streams.

Load*Flex* employs an algorithm that "co-optimizes" the dispatch of a DR program across the hourly marginal cost series from Step 3, subject to the operational constraints defined in Step 1, such that overall system value produced by the program is maximized. In other words, the programs are operated to reduce load during hours when the total cost is highest and build load during hours when the total cost is lowest, without violating any of the established conditions around their use. Figure 22 illustrates how the dispatch of the High Sensitivity Case portfolio in this study compares to the hourly cost profile on those same days.

Figure 22: Illustrative Program Operations Relative to "Stacked" Marginal Costs



Through an iterative process, Load*Flex* determines when the need for a given value stream has been fully satisfied by DR in each hour, and excludes that value stream from that hour for incremental additions of DR. This ensures that DR is not over-supplying certain resources and being incorrectly credited for services that do not provide additional value to the system.

Step 5: Identify cost-effective incentive and participation levels

A unique feature of Load*Flex* is the ability to identify participation levels that are consistent with the incentive payments that are economically justified for each DR program. This ensures that each program's economic potential estimate is based on an incentive payment level that produces a benefit-cost ratio of 1.0. Without this functionality, the analysis would under-represent the potential for a given DR program, or could even exclude it from the analysis entirely based on inaccurate assumptions about uneconomic incentive payments levels.

As a starting point, participation estimates for each DR program are established to represent the maximum enrollment that is likely to be achieved when offered in NSP's service territory at a "typical" incentive payment level. The estimates are tailored to NSP's customer base using data on current program enrollment, as well as survey-based market research conducted directly with

NSP's customers.[36] For DR programs not included in the market research study, we developed participation assumptions based on experience with similar programs in other jurisdictions and applied judgement to make the participation rates consistent with available evidence that is specific to NSP's customer base.

Table 11 summarizes these "base" participation rates for conventional DR programs. In all cases, participation is expressed as a percent of the eligible customer base. For instance, the population of customers eligible for the smart thermostat program is limited to those customers with central air-conditioning.

The 2017 values represent current participation levels. Values in future years reflect participation rates if the programs were offered as part of an expanded DR portfolio. This accounts for the fact that a single customer could not simultaneously participate in two different programs.

Residential air-conditioning load control participation assumptions reflect a transition from compressor switch-based direct load control program to a smart thermostat-based program. These programs are currently marketed by NSP as "Savers Switch" and "AC Rewards", respectively. Based on the aforementioned primary market research conducted in NSP's service territory, we estimate that a 66% participation rate among eligible customers is achievable at the medium incentive level for these programs collectively. In 2017, participation in air-conditioning load control programs reached 52% of eligible residential customers, mostly through the Savers Switch program. In the future, NSP will increase its marketing emphasis on the AC Rewards program as its primary air-conditioning load control program. Therefore, we assume that achievable incremental participation in residential air-conditioning load control transitions from an equal split between AC Rewards and Savers Switch in 2018 to a 75/25 split in favor of AC Rewards by 2023. Additionally, NSP will focus on transitioning customers from Savers Switch to AC Rewards as compressor switches reach the end of their useful life. Based on information about the age of deployed switches and conversations with NSP, we assume that the number of switches replaced by smart thermostats grows from around 6,600/year in 2018 to 10,000/year in 2023 and onwards.

It is important to note that the participation rates shown are consistent with a participation incentive payment level that is representative of common offerings across the U.S. Participation rates are shown for all programs at these incentive levels, regardless of whether or not the programs are cost-effective at those incentive levels.[37] Later in this section of the appendix, we describe adjustments that are made to these "base" incentive levels to reflect enrollment that could be achieved at cost-effective incentive levels.

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[36] Ahmad Faruqui, Ryan Hledik, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," April 2014.

[37] This is the basis for our estimate of "technical potential".

Table 11: Participation Assumptions for Conventional DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	A/C DLC - SFH	52%	50%	39%
Residential	Smart thermostat - SFH	0%	16%	24%
Residential	Smart thermostat - MDU	0%	35%	32%
Small C&I	A/C DLC	0%	30%	30%
Small C&I	Interruptible	0%	14%	12%
Small C&I	Demand Bidding	0%	2%	1%
Medium C&I	A/C DLC	73%	64%	64%
Medium C&I	Interruptible	3%	13%	11%
Medium C&I	Demand Bidding	0%	6%	5%
Large C&I	Interruptible	12%	44%	43%
Large C&I	Demand Bidding	0%	5%	4%

Notes:
Participation rates shown for programs at the portfolio level (i.e. accounts for program overlap). Lower participation rates for some programs in 2030 relative to 2023 result from customers switching to an opt-in CPP rate (for which participation estimates are shown separately). High Medium C&I participation in A/C DLC is relative to a small portion of the customer segment that is eligible for enrollment.

Table 12 illustrates the potential participation rates for each new DR program analyzed in the study. As noted above, these enrollment rates are consistent with "base" incentive payment levels and do not reflect enrollment associated with cost-effective payment levels. **Here, participation in each program is shown as if the program were offered in isolation.** In other words, it is the achievable participation level in the absence of other programs being offered. In our assessment of expanded DR portfolios that include multiple new DR programs, restrictions on participation in multiple programs are accounted for and the participation rates are derated accordingly.

Table 12: Participation Assumptions for New DR Programs
Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	Behavioral DR (Opt-out)	0%	80%	80%
Residential	CPP (Opt-in)	0%	0%	20%
Residential	CPP (Opt-out)	0%	0%	80%
Residential	EV Managed Charging - Home	0%	20%	20%
Residential	EV Managed Charging - Work	0%	20%	20%
Residential	Smart water heating	0%	15%	50%
Residential	Timed water heating	0%	50%	50%
Residential	TOU - EV Charging (Opt-in)	0%	0%	20%
Residential	TOU (Opt-in)	1%	0%	16%
Residential	TOU (Opt-out)	0%	0%	80%
Small C&I	Auto-DR (A/C)	0%	5%	5%
Small C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Small C&I	Auto-DR (Light Zonal)	0%	5%	5%
Small C&I	CPP (Opt-in)	0%	0%	20%
Small C&I	CPP (Opt-out)	0%	0%	80%
Small C&I	TOU (Opt-in)	3%	0%	10%
Small C&I	TOU (Opt-out)	0%	0%	80%
Medium C&I	Auto-DR (HVAC)	0%	5%	5%
Medium C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Medium C&I	Auto-DR (Light Zonal)	0%	5%	5%
Medium C&I	CPP (Opt-in)	0%	14%	14%
Medium C&I	CPP (Opt-out)	0%	79%	79%
Medium C&I	Thermal Storage	0%	3%	3%
Medium C&I	TOU (Opt-in)	21%	19%	19%
Medium C&I	TOU (Opt-out)	0%	0%	80%
Large C&I	Auto-DR (HVAC)	0%	5%	5%
Large C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Large C&I	Auto-DR (Light Zonal)	0%	5%	5%
Large C&I	CPP (Opt-in)	0%	22%	22%
Large C&I	CPP (Opt-out)	0%	81%	81%
Large C&I	TOU (Opt-in)	100%	100%	100%

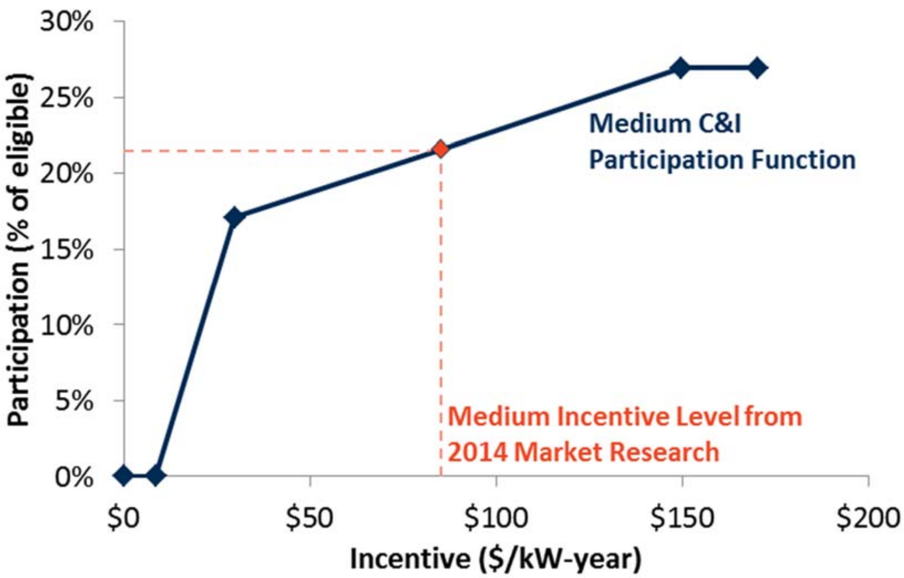
Notes:
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

As discussed above, the cost-effectiveness screening process in many DR potential studies often treats programs as an all-or-nothing proposition. In other words, the studies commonly assume a base incentive level and then simply evaluate the cost-effectiveness of the programs relative to that incentive level. However, in reality, the incentives can be decreased or increased to accommodate lower or higher thresholds for cost effectiveness. For instance, in a region with lower avoided cost, a lower incentive payment could be offered, and vice versa. Program participation will vary according to these changes in the incentive payment level.

In Load*Flex* model, participation is expressed as a function of the assumed incentive level. The incentive level that produces a benefit-cost ratio of 1.0 is quantified, thus defining the maximum potential cost-effective participation for the program.[38] The DR adoption function for each program is derived from the results of the aforementioned 2014 market research study, which tested customer willingness to participate in DR programs at various incentive levels.

An illustration of the participation function for the Medium C&I Interruptible program is provided in Figure 23. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis). At an incentive level of around $85/kW-yr, slightly more than 20% of eligible customers would participate in the program. If the economics of the program could only justify an incentive payment less than this (e.g., due to low avoided capacity costs), participation would decrease according to the blue line in the chart, and vice versa. Below an incentive payment level of around $25/kW-yr, customer willingness to enroll in the program quickly drops off.

Figure 23: Medium C&I Interruptible Tariff Adoption Function



Step 6: Estimate cost-effective DR potential

After the cost-effective potential of each individual DR program is estimated, the programs are combined into a portfolio. Constructing the portfolio is not as simple as adding up the potential estimates of each individual program. In some cases, two programs may be targeting the same end-use (e.g., timed water heating and smart water heating), so their impacts are not additive.

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38 In some cases, the non-incentive costs (e.g., equipment costs) outweigh the benefits, in which case the program does not pass the cost-effectiveness screen.

In instances where two cost-effective programs target the exact same end-use, we have assumed that the portfolio would only include the program that produces the larger impact by the end of the study horizon. In the water heating example, this means that the smart water heating program was included and the timed water heating program was not.

In other cases, two "competing" programs would likely be offered simultaneously to customers as mutually exclusive options. For instance, it is possible that C&I customers would only be allowed to enroll in either an interruptible tariff program or a CPP rate. Simultaneous enrollment in both could result in customer being compensated twice for the same load reduction – once through the incentive payment in the interruptible tariff, and a second time through avoiding the higher peak price of the CPP rate. In these cases, we relied on the results of the aforementioned 2014 market research study, which used surveys to determine relative customer preferences for these options when offered simultaneously. Participation rates were reduced in the portfolio to account for this overlap.

In cases where two programs would be offered simultaneously to the same customer segment, but would target entirely different end-uses (e.g., a smart thermostat program and an EV charging load control program), no adjustments to the participation rates were deemed necessary.

Appendix B: NSP's Proposed Portfolio

At a stakeholder meeting on August 8, 2018, NSP presented a draft portfolio of proposed DR programs. The DR portfolio that NSP is considering consists of the programs and deployment years summarized in Table 13.

Table 13: NSP's Draft Portfolio of DR Programs

Program	First Year of Rollout
Saver's Switch	Existing
A/C Rewards	Existing
EV home charging control	2020
Med/large C&I Auto-DR	2021
Med/large C&I interruptible tariff (program expansion)	2021
Med/large C&I Opt-in CPP	2022
Residential smart water heating	2023
Residential behavioral DR	2023
Residential opt-out TOU	2024

The potential for this portfolio was quantified under the Base and High Sensitivity cases for years 2023 and 2030. Results are summarized in Table 14. In the table, the values in the row labeled "All Proposed Programs" indicate the incremental technical potential in each of the programs that have been proposed by NSP. The values in the row "Cost-Effective Proposed programs" indicate the amount of incremental DR in the proposed programs that can be achieved at cost-effective incentive payment levels. In both cases, DR potential is shown at the portfolio level, accounting for overlap in participation when multiple programs are offered simultaneously.

Table 14: Incremental Potential in NSP's Draft Portfolio of DR Programs (MW)

	Base Case		High Sensitivity Case	
	2023	**2030**	**2023**	**2030**
All Proposed Programs	642	907	658	927
Cost-Effective Proposed Programs	262	461	411	677

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix C: Base Case with Alternative Capacity Costs

For its 2019 IRP, NSP has developed cost assumptions for new CT capacity at brownfield and greenfield sites. Our Base Case assumptions rely on brownfield CT costs as the avoided generation cost estimate, as this is the lowest cost option available to NSP for future peaking generation development. To test the sensitivity of our findings to that assumption, we modeled an alternative case in which the avoided capacity cost in the Base Case is based on a greenfield CT rather than a brownfield CT.[39] Other Base Case assumptions remained unchanged.

The greenfield CT capacity cost is higher than the brownfield CT cost, which increases the benefits of DR programs due to higher avoided generation costs. Relative to the Base Case, the cost-effective incremental potential in the DR portfolio increases by 73 MW in 2023 and by 119 MW in 2030. Nearly all of this increase in potential is attributable to a further expansion of participation in programs that were already cost-effective in the Base Case. The additional potential is mostly in the smart thermostat program, increases from 112 MW to 148 MW in 2023 and from 169 MW to 220 MW in 2030. Other programs that were economic in the Base Case (residential smart water heating, additional C&I interruptible, and demand bidding) also have small increases in cost-effective potential.

The only program that was initially uneconomic under Base assumptions but becomes economic under the greenfield CT capacity cost assumption is HVAC-based Auto-DR: 3 MW of Large C&I Auto-DR becomes cost-effective in 2023, growing to 6 MW in 2030 (in addition to 32 MW of Medium C&I Auto-DR). Together, these programs account for 4% of additional potential in 2023, but over 30% of additional potential in 2030.

Table 15 compares the portfolio-level incremental DR potential for the Base Case with brownfield CT costs to the alternative case with greenfield CT costs. Annual program-level potential estimates are provided in Appendix D.

[39] Table 9 of this report summarizes the greenfield, brownfield and AEO 2018 CT costs used in this analysis.

Table 15: Incremental Cost-Effective Potential in Portfolio of DR Programs with Alternative CT Costs (MW)

	2023	2030
Base Case (Brownfield CT Cost)	306	468
Alternative Case (Greenfield CT Cost)	378	587
Difference (Alternative - Base)	73	119

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix D: Annual Results Summary

Base Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	6	11	17	23	29	30	34	40	49	60
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	20	20	20	20	20	20	20
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	1	1	4	6	6	6	6	7	7
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	4	9	13	17	22	23	25	29	35	42
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	19	19	19	21	22	22	22	22	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	32	32	32	31	30	30	30	30	30	30
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	14	18	16	15	15	15	15	15	15
Medium C&I	Interruptible	45	45	45	31	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	1	6	7	6	5	5	5	5	5	5
Large C&I	Interruptible	58	58	58	55	51	51	50	49	48	47
Portfolio-Level Total		**276**	**296**	**306**	**338**	**393**	**405**	**418**	**433**	**450**	**468**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	180	180	180	204	227	245	262	280	298	315
Residential	Smart water heating	6	13	19	26	33	34	38	44	53	65
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	21	21	21	21	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	19
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	2	10	12	12	12	12	12	12	13	13
Residential	Smart thermostat - SFH	148	148	148	159	170	180	190	200	210	220
Residential	Smart water heating	5	10	15	21	26	27	30	35	42	51
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	31	31	31	31	32	32	32	32	32	32
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	9	18	20	23	26	29	32
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	19	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	21	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	1	2	3	4	5	5	5	5	6	6
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	6	5	5	5	5	5	5
Large C&I	Interruptible	61	61	61	58	54	53	52	51	50	49
Portfolio-Level Total		**335**	**365**	**378**	**418**	**480**	**498**	**517**	**538**	**562**	**587**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	17	17	17	17	17	17	17
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	11	45	57	66	76	76	75	75	75	74
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	17	21	21	22	22	22	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	3	12	15	15	15	15	15	15	15	15
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	32	32	32	32	32	32	32	33	33	33
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	20	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	7	5	5	5	5	5	5
Large C&I	Interruptible	62	62	62	58	55	54	53	52	51	50
Portfolio-Level Total		**380**	**454**	**484**	**524**	**586**	**603**	**623**	**647**	**674**	**705**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	0	0	8	15	22	23	26	31	39	48
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	0	0	8	13	18	19	21	25	30	36
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	21	21	21	22	23	23	23	23	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	14	14	14	14	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	13	13	13	15	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	52	52	52	52	51	51	50	49	48	47
Portfolio-Level Total		**213**	**223**	**262**	**384**	**400**	**410**	**420**	**433**	**446**	**461**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	36	36	36	34	33	33	34	34	34	34
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	15	15	15	15	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	14	14	14	15	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	56	56	56	55	55	54	53	52	51	50
Portfolio-Level Total		**309**	**359**	**411**	**543**	**570**	**585**	**603**	**624**	**649**	**677**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

BOSTON
NEW YORK
SAN FRANCISCO

WASHINGTON
TORONTO
LONDON

MADRID
ROME
SYDNEY

THE Brattle GROUP

Northern States Power Company
Summary of Cost Benefit Analysis Results
IVVO 1.25%

NSPM -AMI- *NPV*

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.57**

NSPM -AMI,FLISR, IVVOS- *NPV*

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.87**

Northern States Power Company
Summary of Cost Benefit Analysis Results

IVVO 1.25% - No Contingency

NSPM -AMI- *NPV*

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.61**

NSPM -AMI,FLISR, IVVOS- *NPV*

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

Northern States Power Company
Summary of Cost Benefit Analysis Results

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Exhibit___(RD-1), Schedule 7
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IVVO 1%

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.46**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.86**

Northern States Power Company
Summary of Cost Benefit Analysis Results

IVVO 1% - No Contingency

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.49**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.02**

Northern States Power Company
Summary of Cost Benefit Analysis Results

IVVO 1.5%

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.67**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.88**

Northern States Power Company
Summary of Cost Benefit Analysis Results
IVVO 1.5% - No Contingency

NSPM -AMI- *NPV*

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.72**

NSPM -AMI,FLISR, IVVOS- *NPV*

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

QUESTIONS ASKED TO VENDORS THROUGH XCEL ENERGY'S eSOURCING SYSTEM FOR THE RFI FOR THE ADVANCED PLANNING TOOL

1.0 Overview and Introduction

1.1 Instructions to Bidders - Indicate whether or not you agree with the instructions to bidders

1.2 What is your company's legal name?

1.3 Indicate your company's entity type.

1.4 List any applicable trade names or d/b/a names associated with your company (if applicable).

1.5 Who is your single point of contact and their title for communications concerning this Proposal?

1.6 Provide the following contact information for the single point of contact:

Address (street, city, state &zip)
Email
Phone
Fax

1.7 What is your internal proposal number for this event?

1.8 If successful in being awarded this contract, who is your duly authorized representative and their position who would be responsible for signing the contract?

1.9 What is the following contact information of your duly authorized representative?

Address (street, city, state & zip)
Email
Phone number
Fax

1.10

1.10.1 List all states that your company is authorized to work in.

1.10.2 What % of work do you typically self-perform? If answer is 100%, a letter of explanation is required and must be submitted with your bid submission. A sample letter has been attached here for your reference.

1.10.3 If you do not self-perform all work, please fill out attached Subcontracting Utilization Report.

Have you attached a completed Subcontracting Utilization Report?

1.11 This proposal shall remain valid for a period of 120 days following the closing of the event. Select Yes if you agree and No if you disagree.

2.0 Scope of Work and Qualifications

2.1 Qualifications

2.1.1 Provide a list of three industry references that can provide input as to the data provided in this RFP. Provide company name, project description, project start date, contact name, contact phone # and completion date.

2.1.2 As an attachment, provide a list of the key personnel you propose to work on this project and include a brief summary of their experience, including any specialized qualifications and certifications.

Select yes to indicate that you have attached a summary of their qualifications or Resume.

2.1.3 Please provide a list of the available resources and their level of expertise.

2.1.4 Please describe your ideal project process.

2.2 Scope of Work and Technical Requirements

2.2.1 Scope of work and/or Technical specifications and description are found attached to this RFx. Bidders should submit their responses based on the requirements listed in the RFx and addendums.

Select Yes if you have submitted your bids based on these requirements.
Select no to indicate you do not comply with the specifications attached. Enter exceptions as an attachment labeled "table of SOW exceptions".

Each Bidder shall be solely responsible for examining the project-specific specifications and make all necessary investigations to be fully informed of all conditions that will affect the completion of the work to be performed.

2.2.2 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 Event Owner via Emptoris messaging functionality before the close of the bidding event. If Xcel Energy agrees that a change is required or if any explanation or interpretation is required, Xcel Energy will issue an Addendum.

Select yes to indicate that you comply with these terms.

Select no to indicate you do not comply with the terms stated above, and provide an attachment of exceptions

2.3 Quality Assurance and Process Control

2.3.1 Please describe your Quality Assurance Program. Attach additional information as needed.

2.3.2 If you are providing material for this project, please describe in detail where they are manufactured and distributed.

2.3.3 What are your auditing process to ensure your goods are in compliance with Xcel's requirements?

3.0 <u>Pricing Requirements</u>

3.1 Have you completed all questions and attachments of the RFP?

3.2 The Bidder is encouraged to offer options (enhancements to components, materials, or parts; regarding performance, reliability, wear ability, and longevity) in addition to, but not as alternates to, the requirements of the Scope of work and Technical Specification. The offering of such options must include a discussion of the advantages and disadvantages of each option.

Have you attached additional options?

4.0 <u>Commercial Terms</u>

4.1 Attached are the Xcel Energy General Conditions for Consulting Services Agreement.

Please select from the responses below.

If you take exceptions, please fill out the attached table of exceptions document.

4.2 Xcel Energy reserves the right to disqualify any and all responses submitted in a format which is either incomplete or does not comply with the rules for the event. Do you agree to comply with these terms?

4.3 This 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 Company.

4.4 Have you verified that your current insurance form has been attached to your Supplier Profile?

4.5 Standard payment terms are net 30 days after receipt of invoice (unless Bidder submits a cash discount for early payment). Do you agree to the standard payment term? Select yes to indicate that you agree with these terms. Select no to indicate you do not comply with the terms stated above, but offer the terms entered into the "Comments" section.

4.6 Xcel Energy is interested in early payment discount terms for all work covered under this proposal. What early payment terms discount does your company offer?

5.0 Financials

5.1 Have you attached your most recently audited Balance Sheet and Income Statement?

5.2 Annual Sales Volume (Each of Last Three Years).

5.3 Provide your Dunn & Bradstreet No.

6.0 Diversity

6.1 Is your company Certified as a diverse supplier?

6.2 If you answered yes to Question 6.1 above, indicate your company's diversity status. If you answered no, please indicate "N/A" as your status.

6.3 Xcel Energy has a commitment to involve diversity business (e.g., minority, women-owned, etc...) in all phases of its procurement processes. How would your organization support Xcel Energy in achieving this objective through the use of Tier II subcontracting plans?

6.4 Currently, what percentage of your purchases are through diverse tier II suppliers?

(in decimal format - i.e.: 99% = .99)

6.5 Are you planning on using diverse Subcontractors for this project?

If Yes please verify that you have thoroughly completed the Subcontracting Utilization Report in Question 1.10.3

6.6 Are you currently barred from doing business with the U.S. Federal Government?

7.0 Functional Requirements

7.1 Is your solution cloud based?

7.2 How is your cloud based solution configurable?

7.3 The Solution will interface with SAP.

7.4 Does your solution integrate Distributed Generation (DG) into Distribution planning load forecasts? If so, how does it properly plan for the effects of DGsystem load?

7.5 What other Distributed Energy Resources (DER) options can your tool incorporate? If "Other", please describe.

7.6 Which socio-economic factors can be incorporated into planning forecasts in your tool? If "Other", please describe.

7.7 Does your solution provide sensitivity analysis capabilities? If so, please describe your methodology.

7.8 Does your solution provide the capability to adjust adoption rates for technologies? If so, please describe your methodology.

7.9 How does your solution provide the capability to adjust forecasts by adjusting policy and subsidization factors?

7.10 Does your solution provide the capability to adjust parameters by political entity? If so, please describe your methodology.

7.11 Currently, when we review load and generation SCADA data for use in our forecasts, we manually decipher what the maximums or minimums are and exclude switching or abnormal periods. What features does your tool have to improve efficiency in this regard?

7.12 Our current forecasting process relies on historical loads, known growth and manual adjustments. What features does your tool have to improve efficiency in forecasting loads?

7.13 Describe any additional efficiency features incorporated into your tool to reduce the planning forecast process (e.g., Automation, data cleansing, etc.).

7.14 Does your solution show historical and forecasted maximums and minimums on the same screen, for both load and generation, at the feeder and substation transformer levels?

7.15 Does your solution have the ability to aggregate load on a regional level?

7.16 Does your solution aggregate load on a state level?

7.17 Does your solution adjust feeder load forecasts by applying factors at the regional levels?

7.18 Does your solution adjust feeder load forecasts by applying factors at the state levels?

7.19 Where have you added the most value to your customers so far?

7.20 Provide examples how your tool supports accurate forecasts which can be used for PUC and regulatory agency reporting, as well as intra-company reporting. Any white papers to support this capability would be of interest.

7.21 Does your solution perform Distribution scenario planning? If yes, describe your methodology.

7.22 Does your solution utilize hosting capacity information? If yes, describe your methodology.

7.23 Can your solution be integrated with EPRI's DRIVE hosting tool without custom code?

7.24 Which other hosting tool(s) does your solution integrate with?

7.25 How many years of feeder and transformer load history can your solution accommodate and account for?

7.26 Can your solution be integrated with Synergi Electric, version 6.0 without custom code?

7.27 Which other major distribution planning tool(s) does your solution integrate with?

7.28 Does your solution utilize Advanced Metering Infrastructure (AMI) data? If so, what devices?

7.29 Does your solution have the ability to incorporate multiple SCADA points on a distribution feeder?

7.30 Can your solution take into account real and reactive power by phase?

7.31 Does your solution record daytime minimum load?

7.32 Does your solution integrate with Hansen Technologies Peace software version 7.1 Customer Resource System without custom code?

7.33 Which other major customer resource system(s) does your solution integrate with?

7.34 Please describe your solution's reporting capabilities.

7.35 Does your solution integrate with Business Objects? If so, please describe how?

7.36 What exporting capabilities does your solution have? If "Other", please describe.

7.37 Does your solution forecast medium term (1-5 years) feeder and substation load growth? If so, describe the forecasting methodology.

7.38 Does your solution forecast long term (+10 years) feeder and substation load growth? If so, describe the forecasting methodology.

7.39 Does your solution integrate with GE's EMS/SCADA system, PowerOn Reliance (XA/21) version 17.1.2 without custom code?

7.40 Which other major SCADA system(s) does your solution integrate with?

7.41 Is your solution able to incorporate GIS Smallworld data? If yes, how?

7.42 Which other major geographic information systems does your solution integrate with?

7.43 Does your solution provide any equivalent planning and forecasting functionality for the following:

7.43.1 Gas Distribution? If so, please describe.

7.43.2 Transmission? If so, please describe.

7.43.3 Generation? If so, please describe.

7.44 Does your solution integrate with any third party products that provide equivalent planning and forecasting functionality for the following:

7.44.1 Gas Distribution? If so, please describe.

7.44.2 Transmission? If so, please describe.

7.44.3 Generation? If so, please describe.

8.0 Security – General, System, Data Integrity

8.1 Security – General

8.1.1 Should you have access to any Company or client confidential information, please describe how confidentiality is maintained, including how information is retained and/or disposed of at designated times.

8.1.2 Describe your employee background check as part of the onboarding process.

8.1.2.1. Do you run background checks on every employee? Please describe your process.

8.1.2.2. Do you run background checks on contractors? Please describe your process.

8.1.2.3. What types of checks are included? Please describe your process.

8.1.2.4. Are criminal background checks performed? Please describe your process.

8.1.3 Does your company have agreements which both employees and contractors sign pertaining to non-disclosure, acceptable use, and code of conduct? If yes, please describe and attach a sample.

8.1.4 Do you have a dedicated internal audit and compliance team in place who govern policies, procedures, approvals, and review processes?

8.1.5 Do you outsource any security management functionality? If yes, please describe what is outsourced, the scope of the outsourced arrangement, and to whom.

8.1.6 Do you have a Computer Security Incident Response Team (CSIRT) in place? If so, please describe your procedures for responding to and reporting security incidents.

8.1.7 Are there any issues with allowing Company to review your information security documents and risk management procedures, including vulnerability assessment results and remediation activities?

8.1.8 Does your company have a process implemented to ensure all violations, unauthorized access (including data protection) and anomalous activities are logged, monitored, reviewed and addressed in a timely manner?

8.1.9 What tools, if any, are used for DLP? Provide a description overview of your DLP program.

8.1.10 Is there a procedure to track announcements of vulnerability patches for your networking devices? If yes, describe the procedure.

8.1.11 Do you have formally written and documented policies and procedures for the following and how often are they reviewed. (For each one, please respond with Yes or No and how often they are reviewed.)

8.1.11.1. Data Classification

8.1.11.2. Acceptable Use

8.1.11.3. Data Handling, Destruction, Retention & Return

8.1.11.4. Remote and Third Party Access

8.1.11.5. Change Management

8.1.11.6. Privacy

8.1.11.7. Incident, Problem & Emergency Management

8.1.11.8. Business Continuity

8.1.11.9. Disaster Recovery

8.1.11.10. Password Management Policies

8.1.11.11. Encryption Policy and Standards

8.1.12 Provide a descriptive overview of your Business Continuity program/plan.

8.1.12.1. Do you test your Business Continuity program/plan capabilities?

8.1.12.2. Based on testing results, what is your operational Recovery Time Objective [RTO]?

8.1.13 Provide a descriptive overview of your Disaster Recovery program/plan.

8.1.13.1. Based on testing results, what is your Recovery Time Objective [RTO] / Recovery Point Objective [RPO] for the technology service that is the subject of this RFI?

8.1.13.2. How often are your Disaster Recover plans tested?

8.2 Security System

8.2.1 Do you have a standard patching process in your environment? If yes, describe automated product/manual process.

8.2.2 Do you have a formal patch/hotfix testing and deployment process?

8.2.3 Do you perform security assessments, web application assessments, or penetration tests against the infrastructure and application (include source code) to identify security vulnerabilities at least twice a year?

8.2.4 What type, and at what frequency, are vulnerability scans performed?

8.2.5 How does your solution handle data validation? Does the solution have a flagging capability for missing data, tolerances for data, or manual data input errors?

8.2.6 Would you be able to configure field based data integrity checks and validation rules?

8.2.7 Describe the cyber security testing of your software/hardware product(s).

8.2.8 Do you deploy secure application development methodologies, such as OWASP, in all or any aspects of software development?

8.2.9 Please indicate how data is transmitted securely between your service locations and the recipients.

8.2.10 Do you use encryption on all of the communication protocols? Please list protocol and encryption method. If encryption isn't used, please explain why.

8.2.11 Please describe your process for performing application security Quality Assurance testing. For example, testing of authentication, authorization, and accounting functions, as well as any other activity designed to validate the security architecture.

8.2.12 Have you completed web code reviews, including CGI, Java, etc., for the explicit purposes of finding and remediating security vulnerabilities?

8.2.13 Describe your software maintenance process, as well as access methods with regard to security / vulnerability patch management.

8.2.14 Do you utilize open source code or operating systems? Please specify.

8.2.15 Does your solution have the ability to lock data entry fields after field users submit data, or workflow is moved to a "completed" status?

8.2.16 Does your solution have audit trail capabilities built into standard reports?

8.2.17 Will each transaction be accounted for on a real-time basis, including:

8.2.17.1. Workstation identification

8.2.17.2. Window name

8.2.17.3. Mobile device

8.2.17.4. Application name

8.2.17.5. OS user name

8.2.17.6. Application execution name

8.2.17.7. User name

8.2.17.8. Timestamp

8.2.18 Describe the configuration abilities for security, data integrity and version control in the document repository.

8.2.19 Please indicate the ability to exchange data with SFTP services.

8.2.20 What TCP/IP services are invoked by your software?

8.2.21 Can a new individual contact or group be established as "private" or "public"?

8.2.22 Describe the process for updating custom data fields if they persist in multiple areas of the solutions.

8.2.23 Will your solution allow, store, and create encrypted Zip / compressed files?

8.2.24 Does your solution have the ability to apply security at different levels within an organizational or cost center hierarchy?

8.2.25 Will your solution support secure messaging? Please explain.

8.2.26 Does the system maintain an audit trail on both customized and standard data fields (name of data field, who made the change, when it was changed)? Please attach a sample screen shot. Is this information reportable?

8.2.27 Does your solution use service accounts and if so, do they require password expiration?

8.2.28 What version of program languages is your product based on, and what version of languages are used?

8.2.29 Encryption algorithms must be of sufficient strength to equate to AES-256. What type(s) of encryption algorithms are used?

8.3 Security – Data Integrity

8.3.1 Company reserves the right to periodically audit the environment in which its data will be stored to ensure compliance with Company security standards. This includes physical and non-intrusive network audits performed randomly and without notice. More intrusive on-site network and physical audits may be conducted with advance notification of 1 - 3 weeks. Please indicate if this is acceptable, if not, why?

8.3.2 What policies and controls are in place to prevent Company's data from being "co-mingled" with data from other entities?

8.3.3 Will you use Company data for benchmarking?

8.3.4 Is any part of your solution cloud hosted? If yes, will Company's data be potentially or actually stored outside of the United States?

8.3.5 How is data used in test, development and other non-production environments protected? Is client data scrubbed/de-personalized in these environments? Please explain.

8.3.6 What are the real and actual data retention periods?

8.3.6.1. How long do you keep backups that can be restored?

8.3.6.2. How long is data actually kept prior to being overwritten and/or purged from the data stores?

8.3.6.3. Does it vary by customer, by solution, by module?

8.3.7 Does your solution have purge/archive capabilities?

8.3.8 Can archived data be queried using a standard query tool?

8.3.9 Does your solution have the ability to make certain records / data private?

8.3.10 How does your solution handle legal hold data? Please provide details.

8.3.11 The equipment hosting your solution and Company data must be located in a physically secure facility, which requires badge access at a minimum. Please describe the environment.

8.3.12 Do all data storage locations have 24-hour security guard coverage 7 days a week?

8.3.13 Is sensitive data of any type (credit card number, account login, passwords, PII, PHI) stored in encrypted form? How is the data encrypted?

8.3.14 If you are audited by another customer, will Company's proprietary data be exposed?

8.3.15 Please describe your IPS / IDS environment and how Company data is protected from attack.

9.0 <u>Security – Logging, Authorization, Authentication, Mobile Devices</u>

9.1 Security-Logging

9.1.1 Does your solution create detailed log files? If so, how are the log files accessed?

9.1.2 Do log files show clear text data transactions and credentials?

9.1.3 What type of information is collected in system logs? (Web, database, application, firewall and other network equipment.) Please explain.

9.1.3.1. How long is this information retained? Please explain.

9.1.3.2. How is this information reviewed and at what interval? Please explain.

9.1.4 What security events does the software log and how is it logged?

9.1.5 Please describe the transactional logging that occurs in the system.

9.1.5.1. Would Company have the ability to see the logs?

9.1.5.2. Would Company have the ability to report from the logs all transactional access, usage, information from third party tool integration?

9.1.5.3. Would Company have vendor based administration access?

9.1.6 Describe your source code protections.

9.1.7 Can or do logs normalize multiple time zones?

9.1.7.1. Are there any limitations when accessed from mobile devices?

9.1.8 Is sensitive information ever "in the clear" or unencrypted in logs or any other transient storage?

9.2 Security-Authorization and Authentication

9.2.1 How are security, access levels (read/write), permissions, and other administrative features handled?

9.2.2 Do you support multi-factor authentication?

9.2.3 Does your solution have the ability to create role based security access?

9.2.4 Will all permission levels allow for specific modifications at the granular level to specific modules, screens, custom codes, fields, etc.? Please explain.

9.2.5 How will your solution provide security levels at the individual role and any group levels? Within a project, or department?

9.2.6 Are credentials stored in a relational database?

9.2.7 Is the system compatible with single sign on, or a federated trust relationship?

9.2.8 Does your solution have the ability to apply security at different levels within an organizational or cost center hierarchy? If yes, please explain.

9.2.9 Does your solution enforce secure access based upon Active Directory user or group permissions?

9.2.10 Does your solution support SAML 2.0?

9.2.11 If your product is based on web services, what authentication do you offer?

9.2.12 Is cloud-hosted data encrypted at rest?

9.3 Security-Mobile Devices

9.3.1 Does your solution provide support for mobile technologies? If so, please specify.

9.3.2 Does your solution have security alerts for detected anomalies with mobile platforms?

9.3.3 Are there any constraints when the client uses an MDM solution?

10.0 <u>Architecture, Integration, Infrastructure, Organization, Reliability</u>

10.1 Architecture

10.1.1 What architecture model best describes your application(s)?

10.1.2 What database systems does your application support (and versions)?

10.1.3 What programming languages were used to build the application?

10.1.4 Which server platforms does your application support (and versions)?

10.1.5 Which desktop platforms does your application support (and versions)?

10.1.6 Which web browsers are certified for your application (and versions)?

10.1.7 What local (client side) objects does your application include?

10.1.8 What middleware does your application support?

10.1.9 If Java is required at the desktop, what version is necessary?

10.1.10 What third party software is required by the application or can be launched?

10.2 Application Integration

10.2.1 Do you have experience integrating with SAP? If so, please provide details.

10.2.2 Provide the names of applications your solution integrates with.

10.2.3 What application integration model best describes your system's integration capabilities? (For example, Web Services, Proprietary Published API)

10.2.4 What integration products are supported by the application?

10.2.5 Does this application utilize any integration technology standards? (For example, Web Services, JMS)

10.2.6 Does the application integrate with enterprise applications? If so, how?

10.2.7 What are the Service-Oriented Architecture capabilities of your application? (For example, How does your application expose its core functionality to other collaborating applications?)

10.2.8 Describe how your application depends on or interacts with an enterprise service bus.

10.2.9 Describe your applications' use of open source technology. Please provide a list of all open source technology used.

10.3 Application Support & Shared Services

10.3.1 Is your application configurable? If yes, what customization capabilities does your application support? (For example, allowing Users to customize screens & make online changes to configuration data on field devices)

10.3.2 How scalable is your application? (For example, what's the maximum number of proven clients)

10.3.3 What are the reporting capabilities of your application?

10.3.4 Does your application integrate with Knowledge Management/collaboration tools? If so, how?

10.3.5 Does your application integrate with Data Warehouse products? If so, how?

10.3.6 Do you integrate with Document and Records Management products?

10.3.7 Describe the application user Interface.

10.3.8 Describe the amount of time estimated to implement the application (vanilla), including interfaces to other applications.

10.3.9 Describe the application administration effort.

10.3.10 What reporting tools do you recommend for your solution?

10.4 Infrastructure

10.4.1 Describe the application security design.

10.4.2 Does your application integrate with any services for authentication and group membership? If yes, which authentication products does your application integrate with. (For example, Active directory)

10.4.3 Does the application integrate with third party Web Single Sign-On products? If yes, what third party Web Single Sign-On products does it integrate with? In particular, is your Application supported on PING Platform?

10.4.4 Describe the e-mail requirements of the application.

10.4.5 Describe the service and support features of the application.

10.4.6 Describe the upgrade and release information of the application.

10.4.7 Describe the supporting documentation/resources for the application.

10.4.8 Describe the training for the application (User and Support).

10.4.9 Describe the availability and Disaster Recovery features of the application.

10.4.10 Describe the operational monitoring capabilities of the application.

10.4.11 Does your application run on Windows Server 2012 R2 or Windows Server 2016?

10.4.12 Does your application interface has to be a heavy client? If so, does it run on Windows 7 or Windows 10?

10.4.13 Does your application run on following Database versions? SQL SERVER 2012, SQL SERVER 2016, Oracle 11G, and Oracle 12.x

10.4.14 Does your application have the ability to exchange data using Web Services (through XML, and or REST APIs) in a Websphere 8.x environment? If not, please specify the Web Services Infrastructure that supports your

10.5 Application Service Provider (ASP) Considerations

10.5.1 Do you provide an ASP service for your products, or is the application offered in an ASP format? Please describe.

10.5.2 Describe the system availability for the application (For example, how is availability measured? How is a test/development environment managed?)

10.5.3 Describe the backup and recovery procedure for the application.

10.5.4 Is your product secure? If so, please describe the security of the product.

10.5.5 Describe the encryption capabilities of the application (at rest and in transit)

10.5.6 Describe the anti-virus solution in place, if applicable.

10.5.7 Describe the support for the hosted information for the application. (For example, End User and Application Support capabilities of the ASP)

10.5.8 Describe the physical hosting information for the application. (For example, where is the service located, do you rely on other partners?)

10.5.9 Describe the scalability of the application.

10.5.10 Describe the release strategy for your product.

10.5.11 Describe the vertical application integration barriers of the application. (For example, are there any key barriers to integration and customization?)

10.5.12 Do you have previous experience in migrating data from legacy systems (other than your own) to your application(s).

10.5.13 Do you have native integration to SAP or is a custom integration using SAP PI required? Please describe.

10.6 Organization

10.6.1 Have you supplied the proposed solution to other utilities sectors, either directly or through a partnership with a System Integrator?

10.6.2 Do you have a "road map" for this product over the next five (5) years? Please provide details.

10.6.3 Please provide details of previous successful implementations with other clients.

10.7 Change Management and Change Controls

10.7.1 Are any principles of the systems development lifecycle (SDLC) methodology followed with respect to application systems?

10.7.2 How are changes to configurations or patch management handled within your system?

10.7.3 Do you support the validation of changes in non-production environments prior to applying changes to the production environment?

10.7.4 How can the impact to the system from changes to the application be validated?

10.7.5 Do you manage multiple instances prior to changes in systems?

10.7.6 Is your solution cloud based?

10.7.7 How is your cloud based solution configurable?

10.8 Security Change Management

10.8.1 How are security patch notifications and evaluations performed prior to applying any changes?

10.8.2 What is the procedure for testing and evaluating the impact of applying security patches on devices prior to apply in the production environment?

10.9 Bandwidth Requirements

10.9.1 What is the proposed bandwidth for your solution? Please justify.

10.10 Reliability

10.10.1 Describe how high availability is achieved by the solution as a whole, as well as by key critical components. Diagrams are welcome.

10.10.2 Describe how disaster recovery across multiple data centers is achieved by your solution.

10.10.3 Describe how data archival and records retention is supported and managed by your solution.

10.10.4 Describe how database replication is supported by your solution.

10.10.5 Explain in detail how scalability is achieved across your solution.

10.10.6 Describe the backup architecture for your system.

10.10.7 Describe how performance optimization is achieved across your solution

10.10.8 Describe how your solution should be monitored, and the monitoring technologies that are supported.

10.10.9 Describe how load balancing is supported, and for what solution components you recommend.

10.10.10 Describe how downtime is minimized for configuration changes and upgrades.

10.10.11 Describe how automative failover and recovery are supported.

10.10.12 Describe how your solution supports multi-side deployments.

10.10.13 Can your application records be archived?

10.10.14 Do you have native archiving, or have a relationship with an archive vendor?

10.10.15 Do you have version control for configurations and customizations?

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

Xcel Energy®

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

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 RESPONSIBLE BY NATURE™

- 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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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

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.
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62. T-min – minimum time
63. T-Max –maximum time
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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.

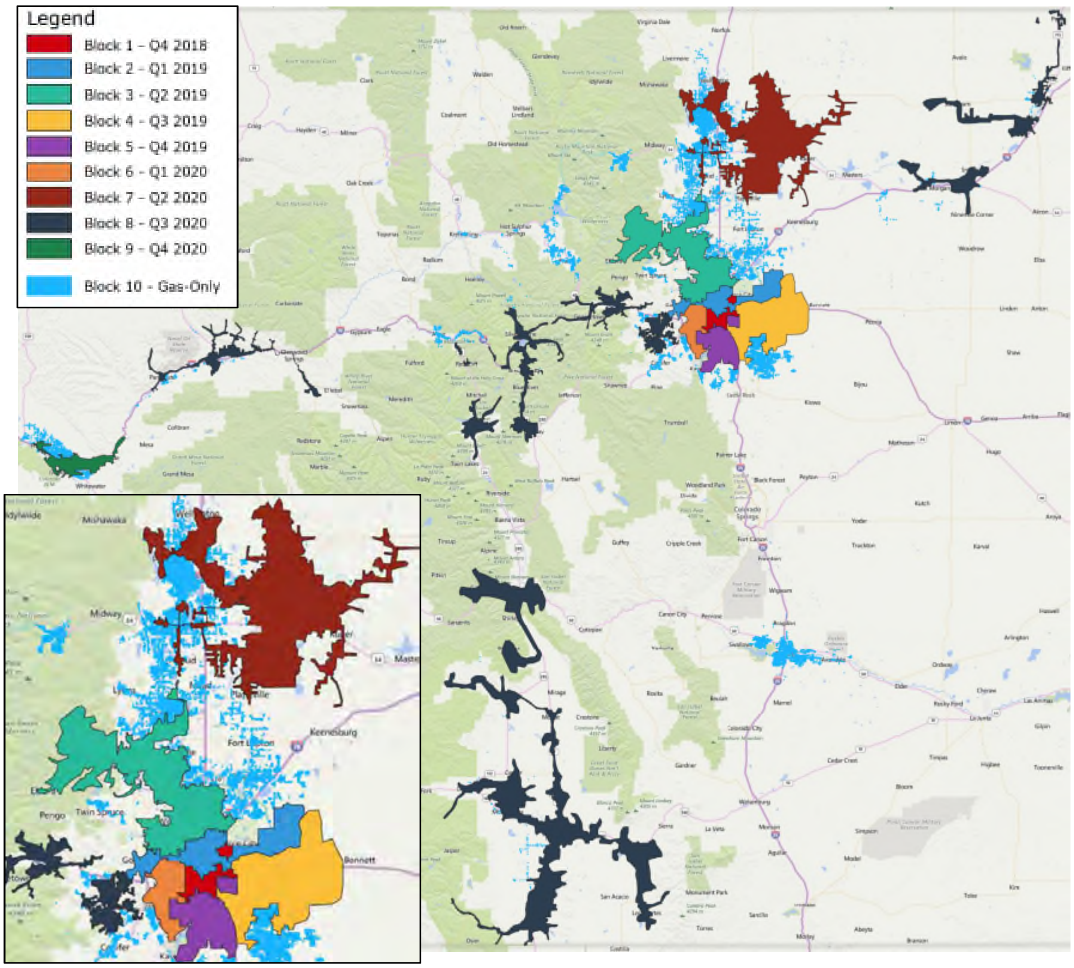
2.2.4 DA Related Geographic Coverage Requirements

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].

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

	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

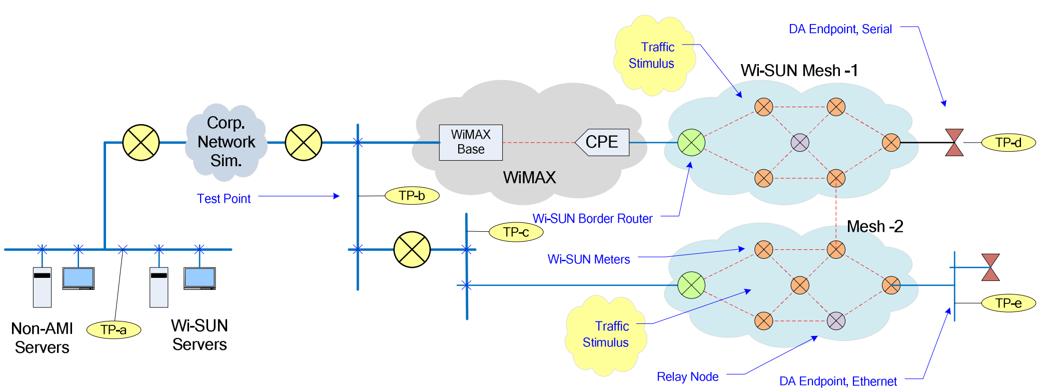
6. Suppliers are required to document the testing undertaken and to provide a detailed report of tests and results within 2 weeks following the completion of the testing.

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.

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,

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.

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.

Low Voltage VAr Compensator RFI

1.0 Purpose

Xcel Energy is herein soliciting information from vendors about Low Voltage VAr Compensator devices (LV VCs). This RFI describes the application for the devices. There is also a section in the RFI with general questions that Xcel Energy requests Vendors respond to, in order to better assist Xcel Energy in understanding each Vendor's product and its market adoption.

- Vendors responses will be reviewed to aid Xcel Energy's market and product knowledge and will be used to aid in Xcel Energy's determination of a vendor to provide LV VCs for at least its Colorado service territory.
- Xcel Energy will execute background checks on each vendor (installed base, relevant clients, financial health, etc)
- Follow up questions to vendors may be issued.

2.0 Distribution list

This RFI is being provided to:

[PROTECTED DATA BEGINS

PROTECTED DATA ENDS]

3.0 Contingency Language

Xcel Energy's down selected AMI and FAN mesh vendor is being determined currently. AMI and FAN mesh final selection is expected between July and August of 2017. Once that decision is finalized, it will be communicated to LV VC vendors.

4.0 Background

Xcel Energy is embarking on an effort to modernize the electric distribution grid across its service territories, defined as the Advanced Grid Intelligence and Security initiative (AGIS). This program encompasses many parallel projects, including a dynamic voltage and power factor optimization project, defined as the Integrated Volt VAr Optimization project (IVVO).

This project will involve installation of new load tap changer controls at substations (LTCs), advanced primary capacitor bank controls (Capacitors), and possibly LV VCs. These devices will work in tandem under the control of a Schneider Electric Advanced Distribution Management System (ADMS) to dynamically adjust voltage and power factor, with the intent of reducing system demand and energy. It is envisioned that LTCs and Capacitor banks will provide the majority of voltage support on each feeder, with the option of LV VCs providing ancillary support to the system.

Currently, it is thought that these LV VC devices will primarily be used on overhead distribution systems; however applications may extend to underground systems as well.

If applied, the LV VC devices would be primarily used in metropolitan areas, within range of Xcel Energy’s Field Area Network (FAN). The devices would have use of the AMI 900 MHz mesh component of that FAN. Optional applications outside of that FAN could leverage 4G cellular technologies. Overhead LV VCs are primarily desired, though Xcel Energy may find applications for pad mounted units as well, both for new construction as well as infill in existing areas.

5.0 Desired Applications

5.1 CVR Steady State Support

This is the primary application for Xcel Energy. Feeders chosen for IVVO could have units deployed to provide ancillary feeder voltage support in conjunction with other voltage support devices. Devices are desired to have local operational settings and regularly provide telemetry to the ADMS. Based on system conditions, the ADMS may provide new settings to override the local device settings, with the intent of realizing Conservation Voltage Reduction or Volt VAr Optimization goals.

5.2 Mitigation of existing DER (Distributed Energy Resources)

LV VC devices may also be connected to distribution transformers with high DER penetration. The LV VC could be used to reduce or eliminate any voltage excursions caused by the intermittent nature of the DER, with the goal of improving customer and feeder power quality.

5.3 New Construction Incorporation

New subdevelopments (particularly residential) within Xcel Energy’s service territory generally have a high DER component. As part of standard metropolitan area construction, Xcel Energy may elect to place LV VCs within new subdevelopments as other construction is underway.

5.4 Specific Local Voltage Issues

There may be cases where a specific issue is identified by Engineering in a small area, or a particular customer has a more sensitive voltage tolerance than the majority of the feeder. In these cases, LV VC devices may be deployed to address the voltage quality.

6.0 RFI Schedule

Below is an approximate schedule for the RFI. Any changes to this schedule will be communicated to Vendor by Xcel Energy representative.

Event	Timeframe	Description
RFI Issue (Day 1)		Xcel issues all RFI questions to Vendors
RFI Responses due (Day 28)	4 weeks	Vendors provide responses to RFI to Xcel
Xcel Energy reviews vendor responses (Day 35)	1 week	Follow up questions determined
Xcel Energy follow up questions issued (Day 56)	3 weeks	Xcel Energy issues any follow up questions to vendors (1 week per Vendor, order to be determined)
RFI follow up responses due (Day 63)	1 week	Vendors provide responses to RFI follow up questions back to Xcel (1 week per Vendor, order based on when follow up questions received)
Xcel Energy reviews follow up responses (Day 77)	2 weeks	RFI responses reviewed, course of action determined and communicated to Vendors

7.0 Vendor Questionnaire

Please see attached document “XCEL Energy LV VC RFI Questions.docx”. This document lists the RFI questions requiring response from the vendors.

Mechanism – Ratings and Design

1A Longevity
What is the average lifespan of one of these devices?

1B Wear Monitoring
Please provide your method of tracking the health of each Low Voltage VAr Compensator (LV VC), including number of operations vs expected total operations count, time installed, etc.

1C AC Switch
Can an integrated, lockable AC disconnect switch be provided within the enclosure to Xcel Energy?

1D Planning
Please provide product roadmaps for the next 24 months for your LV VC device and management software (if applicable).

1E Mounting Bracket
Are mounting brackets available for multi-phase installations of the LV VC on poles? Please provide details about the available mounting brackets, including type of material, applications, installation methods, etc.

1F Voltage Compatibility
Does your product support a voltage range between 208-277 V utilizing either line to line connection or a line to neutral connection?

1G Sensor Accuracy
If applicable, what is the accuracy of the voltage and current sensors in both frequency and magnitude?

1H Safety
How much time is required to safely discharge the device? How does your design accomplish this?

1I Overcurrent Protection
Are there integrated interrupt capabilities in the device? How is overcurrent protection achieved in the device? Is this component serviceable by Xcel Energy?

1J Capacity and Increments
What is the available VAr (Leading) capacity and associated increments? What is the available VAr (Lagging) capacity and associated increments? Are the increments adjustable through the software?

1K Control
Please describe the available control scheme and any mode options.

1L Power Quality
What is the Total Harmonic Distortion (THD) of the device? Please describe any active or passive mitigation features.

Communications

2A Deployments
Please describe any deployments done specifically using AMI 900 MHz mesh radio communications hardware. Include communications vendor and model information, deployment locations and dates, number of devices, count of units RMA'd, and a customer reference that can be contacted.

2B GPS
Has GPS been integrated into your device? If not, is it on your roadmap and when is that integration planned?

2C Software
Please provide a network diagram describing your management software, its connection to the LV VC units in the field, and its interaction with a SCADA or ADMS.

2D Data Usage
Please provide the average data usage of your devices over a month and year (including firmware updates).

2E FAN Network Compatibility
Can the device be integrated within an AMI mesh radio systems?

2F Management Server Capabilities
Do you have a method (through a management server or otherwise) of reporting information about your devices and controlling them at a fleet level (device status, firmware version, etc.)? Please describe your solution and whether it can be fully contained and integrated in the Xcel Energy IT environment or if it relies on public infrastructure (i.e. "cloud").

Commercial

3A Total Units

Please provide a count of total units installed in the field.

3B Deployments – Current

Please provide Xcel Energy your 5 largest customers by deployment size. Include deployment locations and dates, number of devices, customer use cases, count of units RMA'd to date, and a customer reference that can be contacted. Please also include what communication mediums are being used by your 5 largest customers?

3C Deployments – Future

Please provide information on any deployments actively planned for the next 6 months. Information should include customer name, deployment location and dates, number of devices, and a customer reference that can be contacted. Please also include what communication mediums will be used by your 5 largest customers?

3D Pricing – LV VC

Please provide an itemized quote for each valid LV VC configuration (overhead, pad mount, pedestal mount, cellular option, AMI 900 MHz mesh radio, associated brackets, AC disconnect switch, etc.).

3E Pricing – Installation

Please provide estimates from previous customer installs on the amount of time required by a construction crew to install your device, for both overhead and pad mount applications.

3F Pricing – Ongoing Costs

Please provide any expected ongoing costs (software licensing, technical support, cellular service, etc.).

3G Market Sustainability

How many years of experience does your company have with low voltage VAr compensators?

3H Supply and Origin

Where are the components for the LV VCs manufactured? Where are these components assembled?

3I Lead Times

Please provide estimated lead times for your LV VC units.

Application Support

4A Integration

Please provide any information on integrating your LV VC device in centrally managed IVVO schemes. Include customer name, location, dates, ADMS vendor name, and results of the integration.

4B Construction

Have customers installed your devices on poles with secondary but away from transformers? (For instance, several poles away from a transformer but on the same secondary connection). What has their experience been with these? How did they go about notifying trouble or construction crews that your device is located on that secondary?

4C Connection

Please provide any research done on the effect of connecting your LV VC device on a single or 2 phases of three phase transformers. Specifically, include any research done on impact to customer loads with 1 or more unsupported phases (specifically three phase motor loads).

4D DER

Please provide any research done on mitigating the effects of DER using your LV VC device.

4E Modeling

Please describe your experience modeling your device on real world utility systems. Include approximate number of utility feeders modeled and which customers those feeders were on at a minimum.

4F Maintenance

Please provide any recommended maintenance schedules for your device, by component as applicable. Are there any components that the customer can repair without the manufacturer?

4G Voltage Rise

Please provide typical customer voltage rise margins that are seen at installations. For example, small single-phase loads vs larger three-phase loads.

Testing

5A Test Reports

Please provide certified test reports for the device.

5B Enclosure Protection

Please provide test reports for corrosion control of the enclosure, environmental test reports, intrusion protection, as well as any tests for cyber protection.

5C Mean Time Between Failure

Please provide any information available on experienced Mean Time Between Failure (MTBF) of your LV VC device. Information should be broken out between data from customer installs and data from Vendor lab testing, and should also be broken out between communications module and control modules (if applicable).

5D Failure

Please provide the experienced infancy failure rate of your devices (defined as the rate of device failure within 30 days of customer installation). Please depict failure rates for components separately (communications module, voltage regulation device, VAr injecting device, controller, etc.).

IVVO 1.25%

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.57**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.87**

IVVO 1.25% - No Contingency

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.61**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

IVVO 1%

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.46**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.86**

IVVO 1% - No Contingency

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.49**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.02**

IVVO 1.5%

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.67**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.88**

IVVO 1.5% - No Contingency

NSPM -AMI- *NPV*

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.72**

NSPM -AMI,FLISR, IVVOS- *NPV*

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
AMI Meters																			
AMI Meters Purchase	1,408,513	1,024,373	13,875,456	71,769,600	67,212,800	4,636,544	1,771,935	1,826,384	1,882,506	1,940,352	1,999,976	2,061,432	2,124,776	2,190,067	2,257,364	2,326,730	2,398,226	**182,707,036**	**132,855,955**
AMI Meter Installation	620,017	450,922	5,054,700	26,145,000	24,485,000	1,689,050	645,500	665,335	685,779	706,852	728,573	750,961	774,036	797,821	822,337	847,606	873,652	**66,743,140**	**48,567,278**
RTU's (Return to Utility- Estimate 3% of installed meters)	0	0	303,282	1,568,700	1,469,100	101,343	0	0	0	0	0	0	0	0	0	0	0	**3,442,425**	**2,619,423**
Vendors deployment Project Management	0	381,182	733,817	1,198,410	1,223,217	624,270	0	0	0	0	0	0	0	0	0	0	0	**4,160,897**	**3,204,164**
AMI Operations (Internal Personnel)	843,677	983,487	1,869,203	2,046,398	2,186,980	1,903,327	0	0	0	0	0	0	0	0	0	0	0	**9,833,071**	**7,716,691**
AMI Operations (External Personnel)	0	0	658,073	1,372,663	1,365,055	637,919	0	0	0	0	0	0	0	0	0	0	0	**4,033,710**	**3,053,879**
Shop & Lab equipment (AMI Field Test, Lab equip)	0	25,888	217,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**243,288**	**203,171**
Distribution Contingencies	442,320	441,341	3,497,637	16,031,519	15,083,091	1,477,238	0	0	0	0	0	0	0	0	0	0	0	**36,973,146**	**28,259,602**
TOTAL - AMI Meters	3,314,527	3,307,193	26,209,569	120,132,290	113,025,244	11,069,690	2,417,435	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***308,136,713***	***226,480,162***
Communications Network																			
FAN Infrastructure Distribution	100,005	650,501	1,279,994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,030,499**	**1,729,867**
FAN Distribution WiMax	322,537	2,097,993	4,128,233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,548,763**	**5,579,166**
FAN Bus Sys Costs	1,709	51,120	88,387	59,329	56,142	15,200	0	0	0	0	0	0	0	0	0	0	0	**271,887**	**217,842**
FAN Bus Sys WiMAX Cost	334,633	10,011,076	17,309,267	11,618,600	10,994,506	2,976,466	0	0	0	0	0	0	0	0	0	0	0	**53,244,549**	**42,660,847**
FAN Bus Sys Contingency	73,854	1,267,037	2,253,221	1,166,606	1,103,942	298,863	0	0	0	0	0	0	0	0	0	0	0	**6,163,522**	**4,979,818**
TOTAL - Communications	*832,739*	*14,077,726*	*25,059,102*	*12,844,535*	*12,154,590*	*3,290,528*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***68,259,221***	***55,167,540***
IT Systems and Integration																			
IT Hardware	1,504,080	2,537,978	2,141,049	545,521	556,814	568,340	580,104	0	0	0	0	0	0	0	0	0	0	**8,433,885**	**7,028,256**
IT Software	1,064,115	1,552,117	5,536,877	4,669,670	323,141	0	0	0	0	0	0	0	0	0	0	0	0	**13,145,919**	**10,838,063**
IT Labor + Project Management	1,725,374	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,725,374**	**1,621,097**
IT Contingency	0	0	0	11,176,589	605,252	548,564	174,031	0	0	0	0	0	0	0	0	0	0	**12,504,436**	**9,642,915**
TOTAL - IT Systems and Integration	*4,293,568*	*4,090,095*	*7,677,926*	*16,391,780*	*1,485,207*	*1,116,904*	*754,136*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***35,809,615***	***29,130,330***
Program Management																			
Change Management	0	1,000,000	1,035,500	1,072,260	1,110,325	1,149,742	1,190,558	0	0	0	0	0	0	0	0	0	0	**6,558,386**	**4,950,734**
Environment/Release Management	0	28,071	2,064,464	2,318,348	1,044,303	355,017	99,666	0	0	0	0	0	0	0	0	0	0	**5,909,870**	**4,617,070**
Finance	0	109,959	193,798	194,658	145,467	0	0	0	0	0	0	0	0	0	0	0	0	**643,882**	**516,017**
PMO	0	288,790	506,590	508,944	381,346	0	0	0	0	0	0	0	0	0	0	0	0	**1,685,670**	**1,350,955**
Security	0	1,105,737	1,144,991	1,185,638	1,227,728	0	0	0	0	0	0	0	0	0	0	0	0	**4,664,093**	**3,748,708**
Supply Chain	0	477,703	487,591	497,685	507,987	0	0	0	0	0	0	0	0	0	0	0	0	**1,970,966**	**1,585,917**
Talent Strategy	238,852	349,325	361,726	185,901	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,135,803**	**977,689**
Delivery and Execution Leadership	0	374,158	1,294,786	1,314,010	667,319	0	0	0	0	0	0	0	0	0	0	0	0	**3,650,273**	**2,916,840**
Contingency	11,943	186,687	354,472	363,872	254,224	75,238	64,511	0	0	0	0	0	0	0	0	0	0	**1,310,947**	**1,033,197**
TOTAL - Program Management	*250,795*	*3,920,430*	*7,443,919*	*7,641,315*	*5,338,699*	*1,579,997*	*1,354,735*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***27,529,891***	***21,697,127***
TOTAL CAPITAL	**8,691,629**	**25,395,444**	**66,390,515**	**157,009,920**	**132,003,740**	**17,057,120**	**4,526,306**	**2,491,719**	**2,568,285**	**2,647,205**	**2,728,549**	**2,812,393**	**2,898,813**	**2,987,889**	**3,079,701**	**3,174,336**	**3,271,878**	***439,735,439***	***332,475,159***
O&M ITEMS																			
Communications Network																			
FAN Network Infrastructure Distribution	0	0	130,976	298,507	271,352	225,136	105,810	54,000	55,118	56,259	57,424	58,612	59,826	61,064	62,328	63,618	64,935	**1,624,966**	**1,036,835**
FAN Network Business Systems	0	0	335,766	3,171,422	2,673,589	1,491,278	499,575	671,918	685,827	700,023	714,514	729,304	744,401	759,810	775,538	791,592	807,978	**15,552,536**	**9,460,970**
FAN WiMAX Cost	233,600	357,245	427,150	434,290	562,241	1,048,049	653,607	0	0	0	0	0	0	0	0	0	0	**3,716,182**	**2,782,723**
NOC Opco Allocation	200,000	408,280	625,097	638,037	651,244	664,725	678,485	692,529	706,864	721,497	736,432	751,676	767,235	783,117	799,328	815,874	832,762	**11,473,181**	**6,445,717**
FAN Network Distribution Contingency	0	0	59,854	136,414	124,004	102,885	48,354	24,677	0	0	0	0	0	0	0	0	0	**496,189**	**363,768**
FAN Network Bus Sys Contingency	0	0	301,130	686,305	623,871	517,616	243,271	124,153	0	0	0	0	0	0	0	0	0	**2,496,348**	**1,830,131**
TOTAL - Communications	*433,600*	*765,525*	*1,879,974*	*5,364,975*	*4,906,301*	*4,049,690*	*2,229,101*	*1,567,278*	*1,447,809*	*1,477,779*	*1,508,369*	*1,539,592*	*1,571,462*	*1,603,991*	*1,637,194*	*1,671,084*	*1,705,675*	***35,359,401***	***21,920,143***
IT Systems and Integration																			
IT Hardware	42,114	1,654,282	1,678,585	1,705,324	1,740,624	1,776,655	1,813,432	1,850,970	1,889,285	1,928,393	1,968,311	2,009,055	2,050,642	2,093,091	2,136,418	2,180,642	2,225,781	**30,743,604**	**17,268,781**
IT Software	27,285	85,988	983,487	1,845,314	2,011,390	2,053,026	2,095,523	2,138,900	2,183,176	2,228,367	2,274,495	2,321,577	2,369,633	2,418,685	2,468,752	2,519,855	2,572,016	**32,597,467**	**17,432,600**
IT Labor	0	2,056,405	1,553,273	1,750,246	1,680,090	1,717,226	1,721,011	1,789,073	1,859,799	1,933,290	2,009,656	2,089,007	2,171,461	2,257,136	2,346,156	2,438,653	2,534,759	**31,907,241**	**17,784,018**
Common Corporate Business System development-Allocation	646,904	4,270,861	5,304,505	11,866,886	12,378,199	10,847,247	10,347,121	0	0	0	0	0	0	0	0	0	0	**55,661,724**	**41,239,207**
IT Contingency	0	997,287	9,826,939	4,112,864	2,099,639	2,145,629	2,192,624	2,240,646	2,289,716	2,339,857	2,391,093	2,443,448	2,496,946	2,551,611	2,607,470	2,664,547	2,722,871	**46,123,186**	**28,075,602**
TOTAL - IT Systems and Integration	*716,303*	*9,064,823*	*19,346,789*	*21,280,633*	*19,909,942*	*18,539,783*	*18,169,711*	*8,019,589*	*8,221,975*	*8,429,907*	*8,643,555*	*8,863,087*	*9,088,683*	*9,320,523*	*9,558,795*	*9,803,697*	*10,055,427*	***197,033,221***	***121,800,207***
Program Management																			
Change Management	0	1,825,114	2,157,971	3,067,323	3,176,213	2,991,329	1,608,666	0	0	0	0	0	0	0	0	0	0	**14,826,616**	**11,214,681**
Environment/Release Management	0	0	22,405	23,200	24,024	24,877	11,794	0	0	0	0	0	0	0	0	0	0	**106,300**	**78,991**
Finance	0	32,456	112,027	167,045	216,218	0	0	0	0	0	0	0	0	0	0	0	0	**527,746**	**410,061**
PMO	0	79,772	275,346	410,574	531,437	0	0	0	0	0	0	0	0	0	0	0	0	**1,297,129**	**1,007,876**
Talent Strategy	37,760	58,651	60,733	0	55,000	0	0	0	0	0	0	0	0	0	0	0	0	**212,144**	**177,898**
Delivery and Execution Leadership	0	217,284	510,624	714,661	897,539	0	0	0	0	0	0	0	0	0	0	0	0	**2,340,109**	**1,829,448**
Contingency	1,888	110,664	156,955	219,140	245,022	150,810	81,023	0	0	0	0	0	0	0	0	0	0	**965,502**	**735,948**
TOTAL - Program Management	*39,648*	*2,323,940*	*3,296,060*	*4,601,944*	*5,145,453*	*3,167,016*	*1,701,483*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***20,275,545***	***15,454,901***
AMI Operations (Personnel)																			
AMI Operations (Internal Personnel)	0	2,029	36,563	40,759	42,206	43,704	47,708	1,040,317	1,077,248	1,115,491	1,155,090	1,196,096	1,238,558	1,282,526	1,328,056	1,375,202	1,424,022	**12,445,575**	**5,756,644**
AMI Operations (External Personnel)	0	187,968	214,121	468,050	1,576,002	1,300,659	1,409,575	1,475,931	1,545,439	1,600,302	1,657,112	1,715,940	1,776,856	1,839,934	1,905,252	1,972,888	2,042,926	**22,688,954**	**11,693,307**
Customer Claims	0	663	1,719	48,916	48,843	7,423	0	0	0	0	0	0	0	0	0	0	0	**107,565**	**81,001**
Total AMI- O&M Dist Contingency	0	29,259	38,605	78,357	249,204	207,032	224,422	387,502	403,894	418,232	433,079	448,454	464,374	480,859	497,929	515,606	533,910	**5,410,717**	**2,687,292**
TOTAL - AMI Operations	*0*	*219,920*	*291,008*	*636,082*	*1,916,255*	*1,558,818*	*1,681,704*	*2,903,750*	*3,026,581*	*3,134,024*	*3,245,282*	*3,360,490*	*3,479,787*	*3,603,319*	*3,731,237*	*3,863,696*	*4,000,857*	***40,652,811***	***20,218,244***
TOTAL O&M	**1,189,551**	**12,374,208**	**24,813,831**	**31,883,634**	**31,877,951**	**27,315,307**	**23,782,000**	**12,490,618**	**12,696,365**	**13,041,711**	**13,397,206**	**13,763,169**	**14,139,931**	**14,527,833**	**14,927,226**	**15,338,477**	**15,761,959**	**293,320,977**	**179,393,496**
GRAND TOTAL CAPITAL & O&M	**9,881,180**	**37,769,652**	**91,204,347**	**188,893,554**	**163,881,691**	**44,372,427**	**28,308,306**	**14,982,337**	**15,264,650**	**15,688,915**	**16,125,755**	**16,575,562**	**17,038,744**	**17,515,722**	**18,006,927**	**18,512,812**	**19,033,837**	**733,056,417**	**511,868,655**

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Avoided O&M Meter Reading Costs																			
Drive-by Meter Reading Cost - O&M	2,155	86,393	1,085,789	2,460,063	3,740,671	3,587,859	4,153,792	4,287,938	4,426,475	4,562,493	4,702,691	4,847,197	4,996,143	5,149,667	5,307,907	5,471,011	5,639,126	**64,507,370**	**33,455,306**
TOTAL - Reduction in Meter Reading Costs	***2,155***	***86,393***	***1,085,789***	***2,460,063***	***3,740,671***	***3,587,859***	***4,153,792***	***4,287,938***	***4,426,475***	***4,562,493***	***4,702,691***	***4,847,197***	***4,996,143***	***5,149,667***	***5,307,907***	***5,471,011***	***5,639,126***	***64,507,370***	***33,455,306***
Reduction in Field and Meter Services																			
Costs savings from remote disconnect capability	0	0	0	0	386,423	1,108,454	1,592,346	1,814,095	1,878,495	2,060,451	2,133,597	2,209,340	2,287,771	2,368,987	2,453,086	2,540,171	2,630,347	**25,463,562**	**12,291,603**
Reduction in trips due to Customer equipment damage	0	0	0	0	32,617	67,549	139,894	144,860	150,003	155,328	160,842	166,552	172,465	178,587	184,927	191,492	198,290	**1,943,406**	**940,688**
Reduction in "OK on Arrival" Outage Field Trips	0	0	0	0	135,529	280,680	581,288	601,924	623,292	645,419	668,331	692,057	716,625	742,065	768,408	795,687	823,934	**8,075,238**	**3,908,746**
Reduction in Field Trips for Voltage Investigations	0	0	0	0	74,833	154,978	320,960	332,354	344,152	356,370	369,021	382,121	395,686	409,733	424,279	439,341	454,937	**4,458,764**	**2,158,225**
TOTAL - Reduction in Field & Meter Services	***0***	***0***	***0***	***0***	***629,401***	***1,611,661***	***2,634,487***	***2,893,232***	***2,995,942***	***3,217,567***	***3,331,791***	***3,450,070***	***3,572,547***	***3,699,373***	***3,830,700***	***3,966,690***	***4,107,508***	***39,940,969***	***19,299,262***
Improved Distribution System Spend Efficiency																			
Efficiency gains reliability, asset health and capacity projects- O&M	0	0	0	0	1,159	2,401	4,972	5,148	5,331	5,520	5,716	5,919	6,129	6,347	6,572	6,805	7,047	**69,067**	**33,431**
TOTAL - Improved Distribution System Spend Efficiency	***0***	***0***	***0***	***0***	***1,159***	***2,401***	***4,972***	***5,148***	***5,331***	***5,520***	***5,716***	***5,919***	***6,129***	***6,347***	***6,572***	***6,805***	***7,047***	***69,067***	***33,431***
Outage Management Efficiency																			
Outage Management Efficiency (Storm spend O&M)	0	0	0	0	604	1,250	2,589	2,681	2,776	2,875	2,977	3,082	3,192	3,305	3,422	3,544	3,670	**35,965**	**17,409**
TOTAL - Outage Management Efficiency	***0***	***0***	***0***	***0***	***604***	***1,250***	***2,589***	***2,681***	***2,776***	***2,875***	***2,977***	***3,082***	***3,192***	***3,305***	***3,422***	***3,544***	***3,670***	35,965	17,409
TOTAL O&M BENEFITS	**2,155**	**86,393**	**1,085,789**	**2,460,063**	**4,371,835**	**5,203,171**	**6,795,840**	**7,189,000**	**7,430,524**	**7,788,455**	**8,043,175**	**8,306,268**	**8,578,011**	**8,858,691**	**9,148,602**	**9,448,050**	**9,757,350**	**104,553,371**	**52,805,408**
OTHER BENEFITS																			
Cost reductions																			
Reduced Consumption on Inactive Meters	0	0	0	0	350,052	714,596	1,458,776	1,488,973	1,519,795	1,551,255	1,583,366	1,616,141	1,649,595	1,683,742	1,718,595	1,754,170	1,790,482	**18,879,538**	**9,235,364**
Reduced Uncollectible / Bad Debt Expense	0	0	0	0	259,816	538,078	1,114,360	1,153,920	1,194,884	1,237,303	1,281,227	1,326,711	1,373,809	1,422,579	1,473,081	1,525,375	1,579,526	**15,480,670**	**7,493,278**
Reduced outage duration benefit	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	**21,103,587**	**10,323,309**
Theft / Tamper Detection & Reduction	0	0	0	0	847,310	1,729,700	3,531,009	3,604,101	3,678,706	3,754,855	3,832,580	3,911,915	3,992,891	4,075,544	4,159,908	4,246,018	4,333,911	**45,698,446**	**22,354,455**
TOTAL - Cost Reductions	0	0	0	0	1,848,467	3,781,151	7,734,769	7,911,371	8,092,215	8,277,408	8,467,062	8,661,292	8,860,217	9,063,955	9,272,633	9,486,379	9,705,322	***101,162,241***	***49,406,407***
Load Flexibility Benefits																			
Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	19,965,050	20,415,850	21,129,600	21,780,000	22,361,590	23,136,860	23,755,800	24,531,638	25,336,224	26,164,958	27,023,654	27,910,308	**283,511,530**	**138,479,332**
Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	1,819,116	1,975,194	2,019,888	2,037,750	2,133,144	2,262,273	2,392,520	2,517,599	2,573,992	2,725,849	2,753,107	2,780,638	**27,991,070**	**13,576,886**
Time Of Usage-TOU-Avoided CO2 Emissions	0	0	0	0	0	226,876	352,119	485,400	361,972	230,903	344,421	271,720	330,772	309,477	297,166	310,767	413,652	**3,935,245**	**1,961,868**
TOTAL - Load Flexibility Benefits	0	0	0	0	0	22,011,042	22,743,163	23,634,888	24,179,722	24,725,637	25,743,554	26,420,040	27,380,008	28,219,692	29,187,972	30,087,528	31,104,598	***315,437,845***	***154,018,085***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,848,467**	**25,792,193**	**30,477,932**	**31,546,259**	**32,271,937**	**33,003,045**	**34,210,616**	**35,081,332**	**36,240,224**	**37,283,648**	**38,460,605**	**39,573,907**	**40,809,920**	**416,600,086**	**203,424,492**
CAPITAL ITEMS																			
Capital gains and other avoided purchases																			
Efficiency gains reliability, asset health and capacity projects- CAP	0	0	0	0	189,547	386,940	789,900	806,251	822,940	839,975	857,363	875,110	893,225	911,715	930,587	949,850	969,512	**10,222,915**	**5,000,776**
Outage Management Efficiency (Storm spend CAP)	0	0	0	0	313,698	649,669	1,345,465	1,393,229	1,442,688	1,493,904	1,546,937	1,601,854	1,658,719	1,717,604	1,778,579	1,841,718	1,907,099	**18,691,164**	**9,047,289**
Avoided Meter Purchases	9,788	18,152	185,992	1,086,102	2,027,125	2,203,315	2,138,852	2,218,752	2,301,754	2,387,984	2,477,572	2,570,653	2,667,369	2,767,866	2,872,297	2,980,823	3,093,609	**34,008,006**	**17,455,428**
TOTAL - Efficiency gains and other avoided CAP purchases	9,788	18,152	185,992	1,086,102	2,530,369	3,239,924	4,274,216	4,418,231	4,567,383	4,721,863	4,881,872	5,047,617	5,219,313	5,397,185	5,581,464	5,772,392	5,970,221	***62,922,085***	***31,503,493***
Avoided Meter Reading CAP investment																			
Drive-by Meter Reading Cost - CAP	20,755	412,501	3,935,923	12,881,148	23,340,750	29,130,716	29,698,551	28,887,914	28,107,557	27,361,868	26,557,430	25,715,024	24,868,419	23,999,536	23,212,398	22,384,139	21,406,031	**351,920,659**	**189,681,697**
TOTAL - Avoided Meter Reading CAP Investment	***20,755***	***412,501***	***3,935,923***	***12,881,148***	***23,340,750***	***29,130,716***	***29,698,551***	***28,887,914***	***28,107,557***	***27,361,868***	***26,557,430***	***25,715,024***	***24,868,419***	***23,999,536***	***23,212,398***	***22,384,139***	***21,406,031***	***351,920,659***	***189,681,697***
TOTAL CAPITAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**25,871,119**	**32,370,640**	**33,972,767**	**33,306,145**	**32,674,940**	**32,083,731**	**31,439,303**	**30,762,641**	**30,087,732**	**29,396,720**	**28,793,861**	**28,156,530**	**27,376,252**	**414,842,744**	**221,185,190**
GRAND TOTAL BENEFITS	**32,698**	**517,046**	**5,207,705**	**16,427,313**	**32,091,421**	**63,366,004**	**71,246,539**	**72,041,404**	**72,377,400**	**72,875,232**	**73,693,094**	**74,150,241**	**74,905,968**	**75,539,059**	**76,403,069**	**77,178,487**	**77,943,522**	**935,996,201**	**477,415,090**

NSPM -AMI- NPV	**Total ($MM)**
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

RATIO SENSITIVITY	VALUE
FAN(80% WiMAx)+ Contingencies	0.83
FAN(80% WiMAx) NO Contingencies	0.99

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Category
CAPITAL ITEMS - SUMMARY																							
FLISR Assets																							
Asset Cost	0	2,456,519	6,604,776	3,745,275	5,606,776	5,852,901	4,447,353	4,539,413	4,633,379	4,729,290	0	0	0	0	0	0	0	0	0	0	**42,615,682**	**29,507,829**	**Direct and Tangible**
Asset Installation	0	661,457	1,804,228	1,037,932	1,576,342	1,669,400	1,286,894	1,332,579	1,379,886	1,428,872	0	0	0	0	0	0	0	0	0	0	**12,177,590**	**8,386,388**	**Direct and Tangible**
Device related Vendor Project Management + Other Labor	0	15,533	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,533**	**13,712**	**Direct and Tangible**
Asset Contingency	0	0	0	1,499,386	1,866,899	919,536	604,982	617,505	630,288	643,334	0	0	0	0	0	0	0	0	0	0	**6,781,930**	**4,638,594**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***3,133,508***	***8,409,004***	***6,282,593***	***9,050,018***	***8,441,837***	***6,339,229***	***6,489,497***	***6,643,552***	***6,801,496***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***61,590,735***	**42,546,523**	
Communications Network																							
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Distribution WiMax	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,227,893**	**1,046,094**	**Direct and Tangible**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	62,744	1,877,077	3,245,488	2,178,488	2,061,470	558,087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,983,353**	**7,998,909**	**Direct and Tangible**
FAN Bus Sys Contingency	48,467	831,493	1,478,676	765,585	724,462	196,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**4,044,811**	**3,268,006**	**Direct and Tangible**
TOTAL - Communications	171,686	3,101,943	5,498,207	2,944,073	2,785,932	754,216	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***15,256,057***	**12,313,008**	
IT Systems and Integration																							
ADMS FLISR Integration	0	372,780	503,962	521,853	1,023,270	1,059,597	807,499	836,165	865,849	896,587	0	0	0	0	0	0	0	0	0	0	**6,887,562**	**4,636,414**	**Direct and Tangible**
IT Contingency	0	0	0	299,788	632,358	654,807	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,586,953**	**1,147,107**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***372,780***	***503,962***	***821,641***	***1,655,629***	***1,714,403***	***807,499***	***836,165***	***865,849***	***896,587***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,474,515***	**5,783,521**	
TOTAL CAPITAL	**171,686**	**6,608,231**	**14,411,173**	**10,048,307**	**13,491,578**	**10,910,457**	**7,146,728**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**85,321,307**	**60,643,052**	
O&M ITEMS - SUMMARY																							
Deployment																							
O&M in support of capital deployment	0	85,389	229,582	130,186	194,892	203,447	154,590	157,790	161,056	164,390	0	0	0	0	0	0	0	0	0	0	**1,481,321**	**1,025,692**	**Direct and Tangible**
TOTAL - Asset Operations	***0***	***85,389***	***229,582***	***130,186***	***194,892***	***203,447***	***154,590***	***157,790***	***161,056***	***164,390***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,481,321***	**1,025,692**	
Ongoing Support																							
On-going Asset/Device support	0	9,416	34,927	50,006	72,532	96,468	115,512	135,303	155,864	177,218	180,886	184,630	188,452	192,353	196,335	200,399	204,547	208,781	213,103	217,514	**2,834,248**	**1,296,703**	**Direct and Tangible**
Component Replacements	0	2,742	10,171	14,562	21,121	28,092	33,637	39,400	45,387	51,606	52,674	53,764	54,877	56,013	57,173	58,356	59,564	60,797	62,056	63,340	**825,333**	**377,600**	**Direct and Tangible**
On-going Communications Network costs	0	7,324	27,166	38,894	56,414	75,031	89,843	105,236	121,227	137,836	140,689	143,601	146,574	149,608	152,705	155,866	159,092	162,386	165,747	169,178	**2,204,415**	**1,008,547**	**Direct and Tangible**
Vendor costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Training	0	10,355	10,723	11,103	11,497	11,906	12,328	12,766	13,219	13,688	14,174	14,677	15,199	15,738	16,297	16,875	17,474	18,095	18,737	19,402	**274,254**	**137,195**	**Direct and Tangible**
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Asset Contingency	0	1,974	7,321	10,482	15,204	20,221	24,213	28,361	32,671	37,147	37,916	38,701	39,502	40,320	41,154	42,006	42,876	43,763	44,669	45,594	**594,092**	**271,804**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***31,810***	***90,308***	***125,047***	***176,769***	***231,717***	***275,533***	***321,066***	***368,368***	***417,495***	***426,339***	***435,374***	***444,604***	***454,032***	***463,663***	***473,502***	***483,554***	***493,822***	***504,312***	***515,028***	***6,732,342***	**3,091,849**	
Communications Network																							
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	
TOTAL O&M	**43,800**	**184,182**	**399,980**	**336,662**	**477,080**	**631,673**	**552,674**	**478,856**	**529,425**	**581,885**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**8,910,447**	**4,639,301**	
GRAND TOTAL CAPITAL & O&M	**215,486**	**6,792,413**	**14,811,154**	**10,384,969**	**13,968,659**	**11,542,130**	**7,699,402**	**7,804,518**	**8,038,826**	**8,279,967**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**94,231,754**	**65,282,354**	

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
O&M BENEFITS																						
Operational Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS																						
Customer Minutes Out- CMO Patrolling savings	0	0	0	40,757	175,083	271,514	355,725	453,382	539,313	649,433	725,847	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	**10,316,013**	**4,528,044**
Customer Minutes Out- CMO Customer Savings	0	0	0	2,754,556	4,809,980	6,277,181	8,295,139	10,426,430	12,214,741	14,325,875	15,433,977	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	**220,019,300**	**98,458,717**
TOTAL CUSTOMER IMPACTS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**
GRAND TOTAL BENEFITS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**

NSPM FLISR- NPV

	Total ($MM)
Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(78)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

RATIO SENSITIVITY	VALUE
FAN(15% WiMax)+ Contingencies	**1.31**
FAN(15% WiMax) NO Contingencies	**1.53**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189	
CAPITAL COSTS																						
Assets/Devices																						
Device costs	0	0	1,512,735	2,824,978	2,704,856	2,267,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,310,319**	**6,996,776**
Device Installation costs	0	0	357,063	773,839	777,449	679,695	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,588,046**	**1,936,047**
Xcel Personnel	0	0	132,317	272,663	277,896	283,603	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**966,479**	**720,811**
Xcel Distribution Personnel [ADMS IVVO Integration]	0	0	306,666	525,184	771,477	772,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,375,999**	**1,760,061**
External resources (Consultants, contractors etc.)	0	0	187,008	434,397	443,389	342,887	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,407,681**	**1,054,169**
E&S	0	103,550	750,582	777,228	804,819	833,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,269,570**	**2,482,269**
Varentec Engineering (ENGO,caps,ami)	0	0	416,731	425,358	434,163	443,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,719,402**	**1,299,884**
Contingency	0	0	107,914	269,162	256,986	175,088	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**809,149**	**607,879**
TOTAL - Business Assets/Devices	*0*	*103,550*	*3,771,016*	*6,302,808*	*6,471,034*	*5,798,235*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*22,446,644*	*16,857,896*
Communications Network																						
Communications Operations-IVVO Budget	0	0	61,332	115,547	110,814	104,193	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**391,886**	**293,733**
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**409,298**	**348,698**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Bus Sys WiMAX Cost	20,915	625,692	1,081,829	726,163	687,157	186,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,327,784**	**2,666,303**
FAN Bus Sys Contingency	0	0	0	1,482,861	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,482,861**	**1,155,589**
TOTAL - Communications	41,073	756,817	1,401,176	2,324,571	797,971	290,222	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*5,611,829*	4,464,323
IT Systems and Integration																						**0**
Xcel Personnel [ADMS IVVO Integration]	0	0	803,466	1,375,982	2,021,270	2,024,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,225,118**	**4,611,361**
External resources (Consultants, contractors etc.) [GEMS]	0	0	520,914	265,849	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**786,763**	**639,234**
GEMS hardware	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Varentec PM & Services	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Project Management	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Travel Expenses	0	0	10,418	5,317	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,735**	**12,785**
Security	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Contingency	0	0	130,158	158,367	190,817	188,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**667,722**	**500,682**
Program Management	0	0	104,183	319,018	325,622	332,362	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,081,185**	**802,089**
TOTAL - IT Systems and Integration	*0*	*0*	*1,881,688*	*2,284,042*	*2,537,708*	*2,545,144*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*9,248,582*	6,949,692
Program Management																						
Organizational Change Management	0	0	468,823	850,715	651,244	553,937	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,524,720**	**1,909,732**
TOTAL - Program Management	*0*	*0*	*468,823*	*850,715*	*651,244*	*553,937*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*				*2,524,720*	1,909,732
TOTAL CAPITAL	**41,073**	**860,367**	**7,522,703**	**11,762,136**	**10,457,957**	**9,187,538**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**39,831,775**	**30,181,642**
O&M ITEMS																						
O&M in support of capital deployment	0	0	17,731	37,764	33,658	34,745	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**123,898**	**92,683**
TOTAL - On-going Asset/Device support Costs	*0*	*0*	*17,731*	*37,764*	*33,658*	*34,745*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*				*123,898*	92,683
Assets/Devices																						
On-going Asset/Device support	0	0	0	0	7,991	25,537	40,714	57,063	59,089	61,187	63,359	65,608	67,937	70,349	72,847	75,433	78,110	80,883	83,755	86,728	**996,591**	**433,842**
Device Replacements	0	0	0	0	12,059	38,654	62,172	85,943	87,722	89,538	91,391	93,283	95,214	97,185	99,197	101,250	103,346	105,485	107,669	109,897	**1,380,003**	**609,942**
Training	0	0	0	0	195	653	1,107	1,554	1,609	1,666	1,725	1,786	1,850	1,915	1,983	2,054	2,127	2,202	2,280	2,361	**27,066**	**11,765**
Contingency	0	0	0	0	2,471	7,885	12,612	17,431	17,792	18,160	18,536	18,920	19,312	19,711	20,119	20,536	20,961	21,395	21,838	22,290	**279,968**	**123,761**
TOTAL - On-going Asset/Device support Costs	*0*	*0*	*0*	*0*	*22,715*	*72,730*	*116,604*	*161,991*	*166,212*	*170,551*	*175,011*	*179,597*	*184,312*	*189,161*	*194,146*	*199,272*	*204,544*	*209,965*	*215,541*	*221,276*	*2,683,629*	1,179,310
Communications Network																						
On-going Communications Network costs	0	0	0	0	4,920	15,829	25,585	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	**567,832**	**250,941**
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN WiMAX Cost	14,600	22,328	26,697	27,143	35,140	65,503	40,850	0	0	0	0	0	0	0	0	0	0	0	0	0	**232,261**	**173,920**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	*14,600*	*22,328*	*26,697*	*27,143*	*40,060*	*81,332*	*66,435*	*35,371*	*36,103*	*36,850*	*37,613*	*38,392*	*39,187*	*39,998*	*40,826*	*41,671*	*42,533*	*43,414*	*44,312*	*45,230*	*800,094*	424,861
IT Systems and Integration																						
Program Management	0	0	22,576	35,446	36,180	36,929	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**131,132**	**98,245**
TOTAL - IT Systems and Integration	*0*	*0*	*22,576*	*35,446*	*36,180*	*36,929*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*131,132*	98,245
Business Program Management																						
Organizational Change Management	0	0	156,274	283,572	217,081	184,646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**841,573**	**636,577**
TOTAL - Program Management	*0*	*0*	*156,274*	*283,572*	*217,081*	*184,646*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*841,573*	636,577
TOTAL O&M	**14,600**	**22,328**	**223,278**	**383,926**	**349,694**	**410,382**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**4,580,325**	**2,431,676**
GRAND TOTAL CAPITAL & O&M	**55,673**	**882,695**	**7,745,981**	**12,146,062**	**10,807,651**	**9,597,920**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**44,412,100**	**32,613,318**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
OTHER BENEFITS																						
Energy Savings																						
Energy Reduction	0	0	165,891	423,491	910,125	1,577,997	1,904,520	1,963,148	2,014,173	2,063,569	2,041,390	1,994,758	2,019,200	2,085,180	2,025,146	2,026,282	2,185,792	2,206,891	2,172,820	2,129,363	**31,909,736**	$14,934,748
Loss Savings	0	0	3,155	8,234	18,167	32,238	39,806	41,776	43,440	44,870	45,454	45,229	46,713	49,088	48,089	48,350	52,370	53,018	52,442	52,442	**724,883**	$333,272
Total Fuel Savings	0	0	169,046	431,724	928,293	1,610,235	1,944,326	2,004,924	2,057,613	2,108,438	2,086,844	2,039,988	2,065,913	2,134,268	2,073,236	2,074,632	2,238,162	2,259,909	2,225,262	2,181,806	**32,634,620**	$15,268,020
Carbon Emissions Benefits																						
Carbon Reduction	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
Total Carbon Emissions Savings	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
TOTAL OTHER BENEFITS	**0**	**0**	**263,744**	**662,427**	**1,407,660**	**2,253,415**	**2,600,664**	**2,650,912**	**2,595,141**	**2,449,229**	**2,399,557**	**2,349,085**	**2,369,024**	**2,419,147**	**2,389,718**	**2,403,054**	**2,579,322**	**2,605,171**	**2,574,626**	**2,535,271**	**39,507,168**	**$18,867,844**
DEMAND BENEFITS																						
Deferral of Capital Investments As Demand Reduction	0	0	45,106	113,532	227,415	386,537	456,612	457,807	459,632	460,716	460,890	465,302	468,166	470,601	475,990	480,620	485,452	488,836	495,037	489,665	**7,387,915**	$3,481,566
TOTAL DEMAND	**0**	**0**	**45,106**	**113,532**	**227,415**	**386,537**	**456,612**	**457,807**	**459,632**	**460,716**	**460,890**	**465,302**	**468,166**	**470,601**	**475,990**	**480,620**	**485,452**	**488,836**	**495,037**	**489,665**	**7,387,915**	**$3,481,566**
GRAND TOTAL DEMAND & OTHER BENEFITS	**0**	**0**	**308,850**	**775,959**	**1,635,075**	**2,639,951**	**3,057,277**	**3,108,719**	**3,054,774**	**2,909,945**	**2,860,447**	**2,814,387**	**2,837,189**	**2,889,748**	**2,865,708**	**2,883,673**	**3,064,774**	**3,094,007**	**3,069,663**	**3,024,937**	**46,895,083**	**$22,349,410**

NSPM IVVO- NPV

	Total ($MM)
Benefits	**22**
Other Benefits	19
CAP Benefits	3
Costs	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (DVO 1.25% O&M; 0.7% capital)	**0.57**

RATIO BASE (DVO Savings 1.25% O&M, 0.7% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.57**
FAN(5% WiMax) NO Contingencies	**0.61**

RATIO LOW SENSITIVITY (DVO Savings 1% O&M, 0.6% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.46**
FAN(5% WiMax) NO Contingencies	**0.49**

RATIO HIGH SENSITIVITY (DVO Savings 1.5% O&M, 0.8% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.67**
FAN(5% WiMax) NO Contingencies	**0.72**