Minnesota Public Utilities Commission
Staff Briefing Papers

Meeting Date: December 4, 2014 .... *Agenda Item **#11**

Company: All Rate-Regulated Electric Utilities

Docket No. **E999/CI-08-948**

In the Matter of the Commission Consideration of Standards Related to Smart Grid Investments and Information under the Federal Independence and Security Act of 2007

Issue: What smart grid projects have utilities reported in their 2014 smart grid reports?

Staff: Andrew Twite .... (651) 201-2245

Relevant Documents

Interstate Power and Light Company, *Annual Report* .... March 29, 2014
Xcel Energy, *Annual Report* .... April 1, 2014
Otter Tail Power Company, *Annual Report* .... April 1, 2014
Dakota Electric Association, *Annual Report* .... April 1, 2014
Minnesota Power, *Annual Report* .... April 1, 2014

The attached materials are workpapers of the Commission Staff. They are intended for use by the Public Utilities Commission and are based upon information already in the record unless noted otherwise.

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List of Acronyms

Acronym	Meaning	Description
ADMS	Advanced Distribution Management System	Xcel's proposed program to enhance distribution system monitoring and control
AMI	Advanced Metering Infrastructure	Also known as "smart meters," AMI enable a wide variety of functions
AMR	Automated Meter Reading	Enable the collection of usage data automatically through touch or by remote transmission
C&I	Commercial and Industrial	Two types of customer classes
DEA	Dakota Electric Association	A rate-regulated cooperative utility
EMS	Energy Management System	A term used by MP and Xcel to refer to their distribution and transmission management systems
ERT	Encoder Reader Transmitter	A device that can be inserted into a meter to enable automated meter reading
EVs	Electric Vehicles	Vehicles powered by electricity
GIS	Geographic Information System	Technology used for the analysis and presentation of spatial or geographical data
GRE	Great River Energy	An electric generation and transmission cooperative
IPL	Interstate Power and Light Company	An investor-owned utility
LiDAR	Light Detection and Ranging	Surveying technique in which helicopters with sensors capture images of transmission lines
MDM	Meter Data Management system	Enhances benefits of AMI and other smart grid technologies, typically via data processing features
MISO	Midwest Independent Transmission System Operator	A Regional Transmission Organization
MP	Minnesota Power	An investor-owned utility
OMS	Outage Management System	Employed by several Minnesota utilities to help locate and assuage outages
OTP	Otter Tail Power Company	An investor-owned utility
PMUs	Phasor measurement units	Devices that make synchronized measurements of current, voltage, and frequency
RTUs	Remote terminal units	SCADA system devices that collect information on the status of circuit breakers and power levels
SCADA	System Control and Data Acquisition	Specialized computer systems that monitor and control grid processes at the substation level
TOU	Time of Use rates	Rate structures that establish fixed time periods across which prices vary
VAR	Volt-Ampere Reactive	The unit used to measure reactive power, which is present when current and voltage are out of phase

Issue

What smart grid projects have utilities reported in their third annual smart grid reports?

Background

On June 5, 2009, the Minnesota Public Utilities Commission (the Commission) issued an Order in Docket No. E-999/CI-08-948 requiring that:

> Beginning on April 1, 2010 and annually thereafter, utilities shall file reports on past, current, and planned smart grid projects, with a description of those projects, including: total costs, cost effectiveness, improved reliability, security, system performance, and societal benefit, with their electric service quality reports.

This Order provides the following working definition of smart grid:

> Smart grid encompasses information and control technology to improve the reliability, security, and efficiency of the electric grid. A smart grid allows deployment and integration of distributed and renewable resources, "smart" consumer devices, automated systems, and electricity storage and peak-shaving technologies.

The first set of reports pursuant to the Order was filed by April 1, 2010, by the five rate-regulated electric utilities and Great River Energy (GRE), and various stakeholders subsequently filed comments and replies.

Staff prepared briefing papers for the December 16, 2010 agenda meeting where this matter was presented as a discussion item, with no substantive decisions contemplated. The Commission expressed interest in getting more complete and uniform types of information from utilities in the next reports and hearing from more of the cooperative and municipal utilities.

On March 4, 2011, the Commission issued a Notice Clarifying Information Sought in Smart Grid Reports (Notice). In this Notice, the Commission indicated that it seeks to clarify the type of information sought in the Smart Grid Reports and would appreciate receiving information on the following topics:

- "Smart" functions enabled with existing infrastructure and systems (please also include what percentage of the utility's meters are currently mechanical, Automated Meter Reading (AMR), or Advanced Metering Infrastructure (AMI), and a sentence on the capability of each);
- Planned or completed system improvements which could affect customer service, power quality, or service quality metrics;
- Current customer access to data (such as usage or outage data) and how that data educates customers; any planned additional customer access to data;
- Time-varying rates and demand response; and
- Discuss the general costs of completed or planned projects (including the costs of changes to billing systems, and if applicable, the early retirements of meters or other equipment) compared to the benefits realized or expected to be realized.

In 2012, no notice was issued, but most utilities referenced the 2011 Notice and submitted their reports consistent with the information requested in the 2011 notice. In 2012, Staff prepared briefing papers for the October 18, 2012 agenda meeting, where this matter was again presented as a discussion item. In March and April of 2013, each of the five rate-regulated electric utilities filed a report; these reports were reviewed by Staff, but briefing papers were not prepared and the subject was not presented at an agenda meeting.

In its consideration of the 2011 Annual Reports at the September 22, 2011 agenda meeting, the Commission initiated a series of workshops on topical smart grid issues. In total, there have been seven of these workshops; the topics are listed below, and more information (including powerpoint slides for each presentation) can be found at this Commission webpage.

- January 6, 2012: Smart Grid and Data Privacy
- April 20, 2012: Reliability and Operations
- November 12, 2012: Electric Vehicles
- April 5, 2013: Time-of-Use Rates
- September 27, 2013: Microgrids
- April 11, 2014: Renewables on the Distribution System
- September 19, 2014: Demand Response

Staff Comment

A persistent question on the national stage is how to analyze smart grid projects to determine whether they should be approved for cost recovery. States determine cost recovery for smart grid projects within their jurisdiction, and each state has different public policies, laws, and procedural rules. In Minnesota, cost recovery in rate cases is generally decided once a cost has been incurred, meaning there is usually not a preapproval process for smart grid or non-smart grid projects. Some Minnesota smart grid projects cited in the utilities' reports are included in their CIP and therefore would be subject to the Department's Evaluation, Measurement and Verification (EM&V) processes.[1] Other projects—particularly those that do not necessarily have quantifiable energy efficiency impacts—may need to be analyzed in another manner.[2] Staff has found it useful to at times discuss with non-rate regulated utilities, Minnesota's municipal and cooperative distribution utilities, to understand how they have analyzed whether to upgrade their technology.[3]

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[1] In large part, the CIP process is also one that does not involve pre-approval of cost recovery; the Commission approves cost recovery after the Department has evaluated the cost-effectiveness of the project after it has been implemented.

[2] For example, Xcel's wind to battery project is cited in its 2014 Annual Report. In the Commission proceeding on this project, Docket E002/M-09-379, the Commission required Xcel to provide a compliance filing to address whether and to what extent the expenses incurred in the project have improved the economics of a nearby wind facility. The Commission placed a $3.5 million cap on the project for purposes of recovery through the RES rider. The project was then rolled into base rates in Xcel's 2011 rate case (Docket E002/GR-10-971).

[3] At the Commission's January 2012 workshop on smart grid and privacy issues, Minnesota Valley Electric Cooperative offered a presentation on privacy which also included helpful information on why the cooperative decided to install AMI meters.

In Staff's opinion, Minnesota is better situated than other states to evaluate smart grid projects because all of the goals identified as part of smart grid—conservation, load-shifting, renewable and distributed resources, reliability—are public policies that have been part of the Minnesota regulatory framework for many years. As such, utilities and stakeholders have experience evaluating projects geared to fulfill these policies. Continuing to gather information and engage in a dialogue with utilities and stakeholders will ensure that Minnesota will be well positioned to address smart grid issues as they continue to present themselves.

Reports and Related Dockets

This summary of the 2014 annual reports is organized by subject, based in part on the Commission's adopted definition of smart grid from its June 2009 smart grid Order. The sections are categorized as follows: Rate Design and Load Management, Meters, Automation/Reliability/Security, Access to Customer Information, Electric Vehicles, Distributed and Renewable Resources.

Where possible, Staff has included a summary of related dockets in order to provide a complete picture of the issues being addressed in Minnesota. Staff has also included section introductions that provide examples of potential smart grid technologies and applications; these examples are not meant to be an exhaustive list of the technologies available in the given field, but rather to alert commissioners to a few technologies that have been more commonly discussed nationally.

Rate Design and Load Management

Under traditional, time-invariant electricity rates, customers do not have an incentive to shift their loads away from peak usage hours. This produces an inefficient generation profile: as a recent Massachusetts Institute of Technology report noted, "It is estimated that fewer than 1% of annual hours (60–100 of 8,760 hours) account for 10%–18% of the capacity needs in North America."[4]

To increase the efficiency of system demand, utilities typically take two types of approaches: rate design, in which time-varying rates encourage customers to shift their loads from high- to low-demand hours; and load management, in which utilities offer benefits to customers who either reduce their usage during specific times and/or allow the utility to control part of their load.

While utilities have been using these techniques for decades, new developments in metering technologies—which are the subject of the following section—offer new possibilities for both rate design and load management. The two-way communications capabilities of smart meters allow near real-time price signals, which enable utilities to use dynamic time of use (TOU) rates. In addition, smart meters also enable "a range of 'smart' energy response and management technologies—such as programmable controllable thermostats and 'smart charging' of electric vehicles—that can, in principle, involve even smaller commercial and residential customers in more active management of their electricity

[4] Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," at page 147.

consumption."[5] While no rate-regulated utilities in Minnesota currently use these advanced techniques, they will likely become more common as more utilities install smart meters.

DEA: Rate Design and Load Management (pp. 9-14)

The Dakota Electric Association (DEA) offers a number of load management and TOU tariffs, some of which have been in place since the early 1980s. Participation varies considerably between programs: 50% of residential customers with central air conditioning participate in the Controlled Air Conditioning Program and 97% of irrigation customers participate in the Interruptible Irrigation program; the company's two TOU programs and its Residential and Farm Demand Control programs, on the other hand, have fewer than 40 (combined) customers between the three programs. The table below summarizes the most popular load management programs offered by DEA, and more detailed descriptions of individual programs can be found on pages 9-11 of the company's 2014 Annual Report.

Name	Description	Number of Customers	Year Initiated
Irrigation (Schedule 36)	Includes an option to interrupt service to irrigation units.	360 – controlled 9 – firm service	Early 1980s
Controlled Interruptible Service (Schedule 52)	Interruptible service to qualifying loads such as electric water heating and space heating, which are remotely controlled by DEA.	7,064	Early 1980s
Full and Partial Interruptible Service (Schedules 70 & 71)	Available to any member-consumer with a minimum controllable demand of 50 kW. Under full interruption, entire electrical energy usage is interrupted.	225 accounts	1990
Controlled Air Conditioning (Schedule 80)	Interruptible service to air conditioners which are remotely controlled by DEA.	38,488	1991
Controlled Energy Storage (Schedule 51)	Available from 11 pm to 7 am. Typical loads enrolled on this program are water heating and space heating.	1,401 (19 with EVs)	Early 1980s

In total, DEA, "is able to control about 20 percent (100 MW) of the 500 MW uncontrolled summer peak load and between 15 and 20 percent (60 MW) of the uncontrolled winter peak load of 320 MW."[6] The majority of this control comes from only two programs: the Controlled Air Condition Program and the C&I Interruptible Service.

IPL: Rate Design and Load Management (pp. 9-10)

Interstate Power and Light Company (IPL) offers five TOU rates and one interruptible rate, though participation is low for all six. The interruptible program, which is available to C&I customers with at least 50 kW of metered demand, has 12 customers with a combined 1.75 MW of demand response. The

[5] Ibid, at page 144.
[6] DEA, 2014 Annual Report, at page 11.

company offers TOU pricing programs to all residential, commercial, industrial, and institutional customers, with a total of 51 total customers.[7]

Name	Description	Number of Customers
Optional Residential TOU rate	7am-8pm is on-peak rate, for residential customers	26
Optional General TOU rate	Available to single-phase service. 7am-8pm is on-peak rate	2
Optional General Demand Metered TOU	7am-8pm is on-peak rate	6
Optional Large Power and Lighting TOU	7am-8pm is on-peak rate	15
Large Power and Lighting-Bulk Supply TOU	7am-8pm. Available to new loads in excess of 4,999 kW at transmission voltages	2
Large Power and Lighting, Interruptible Service	Commercial, industrial, and institutional customers	12

MP: Rate Design and Load Management (p. 7)

As of the filing of its 2014 Annual Report, Minnesota Power (MP) was in the process of finalizing a new TOU rate for Residential customers. The company's Time-of-Day Rate with Critical Peak Pricing was approved by the Commission on November 30, 2012.[8] MP is "currently preparing the final Rate offering for the Time-of-Day Rate to customers and this Rate should be available in the second quarter of 2014."[9]

OTP: Rate Design and Load Management (pp. 4-6)

The table below displays Otter Tail Power Company's (OTP) TOU participation by rate. As the table displays, the company offers several TOU rate options, but overall participation is very low.[10]

Name	Description	Number of Customers	Year Initiated
General Service	Peak pricing program	44	1978
Large General Service		27	1993
Irrigation Service	Peak pricing program	200	1974
Fixed Time of Delivery Service	Off-peak pricing program	468	1996

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[7] IPL also manages stored heat space heating and controlled water heating programs, but these programs are not available to new customers.
[8] Docket No. 12-233.
[9] MP, 2014 Annual Report, at page 7.
[10] OTP offers two more TOU rates—Standby Service-Option A Firm and a Real Time Pricing Rider—that were not included in the table, as there are no Minnesota customers taking service under the rates.

OTP's Direct Control rates, on the other hand, have a much higher participation rate. OTP has employed customer load control technologies since the 1940s. The company's radio control system, which was completed in 2007, enables it to automatically reduce controllable load during periods of capacity constraints or high energy prices. The company offers several direct control tariffs to both commercial and residential customers that encompass a variety of technologies, such as water heaters, air conditioning systems, and heat pumps. In total, OTP had an average of 18,938 customers on Direct Control tariffs in Minnesota in 2013. The table below lists these Direct Control rates offered, and they are described in more detail on page 4 of OTP's 2014 Annual Report.

Name	Description	Number of Customers	Year Initiated
Water Heating	Direct load control program for water heating equipment	8,529	Before 1970
CT Metering Rider ("Large Dual Fuel")	Controlled service, interruptible load program	197	1980s
Self-Contained Metering Rider ("Small Dual Fuel")	Controlled service, interruptible load program	6,073	1980s
Deferred Load Rider ("Thermal Storage")	Controlled service program	842	1980s
Residential Service-Controlled Demand	Direct load control and demand response program for residential customers	2,393	1980s
Air Conditioning Control Rider	Summer season cycling of connected cooling equipment	904	2006

Xcel: Rate Design and Load Management (pp. 24-28)

Of the five rate-regulated utilities, Xcel Energy (Xcel) is the only that has a mandatory TOU rate for a class of customer: TOU rates are mandatory for business customers with peak demand of at least 1MW, and optional for all other business customers. As the table below shows, Xcel offers two business TOU rates: General TOU and Small General TOU. Small General TOU service is available to non-residential customers with a maximum demand of less than 25 kW, and General TOU service is for customers with a maximum demand of 25 kW or more.

Name	Description	Number of Customers	Year Initiated
Small General TOU service	For non-residential customers with a maximum demand less than 25kW.	10,001	1980
General TOU service	For non-residential customers with a maximum demand 25 kW or greater	3,850	1980
Residential TOU service	Off peak rate is roughly 1/3 less than the standard base rate, on-peak rate is roughly double. On-peak time is 9:00 a.m.-9:00 p.m, weekdays.	392	1980

The company also offers a residential TOU rate, but participation is much lower. This is in part due to the unusual load profile needed to save money with this option: the residential TOU rate "typically reduces electric bills for customers that use at least 650 kWh/month, and that have electric heat or water heating or other major loads that can be shifted off-peak. To experience savings on this rate option, customers must use approximately 65 percent or more of their overall electric usage during off-peak periods."[11]

In addition to TOU rates, Xcel also offers several demand response service options. Non-residential customers with a minimum controllable demand of at least 50 kW are eligible for the Peak and Energy Controlled rate, under which customers receive up to a 58% reduction in demand charge over the year for committing to control their demand to a pre-determined level when called upon by Xcel. Another demand response option is the Saver's Switch programs, in which business or residential customers receive discounts from June to September for agreeing to direct load control over their air conditioning systems.[12] The final demand response discount offered by Xcel is the Energy Controlled Service program. Under this program, a business or residential customer that has electric heating as well as an alternative fossil fuel heat source receives a discount for switching to the alternative heat source during peak heating times from October to May. The table below summarizes these demand response programs.

Name	Description	Number of Customers	Controlled Load (MW)
Peak and Energy Controlled rate	Demand charge discount for committing to control demand to pre-determined level whenever Xcel calls for such control. Minimum controllable load of 50 kW.	2,025	488
Saver's Switch: Business	Participating customers receive a monthly discount of $5 per enrolled ton of air conditioning during the months of June through September.	15,917	45
Saver's Switch: Residential	Participants receive a 15 percent discount on their June through September electric energy and fuel cost charges.	376,858	229
Energy Controlled Service	Participating customers agree to switch from their primary electric heat source to an alternative during peak heating times.	3,092	

Meters

<u>Staff Comment</u>

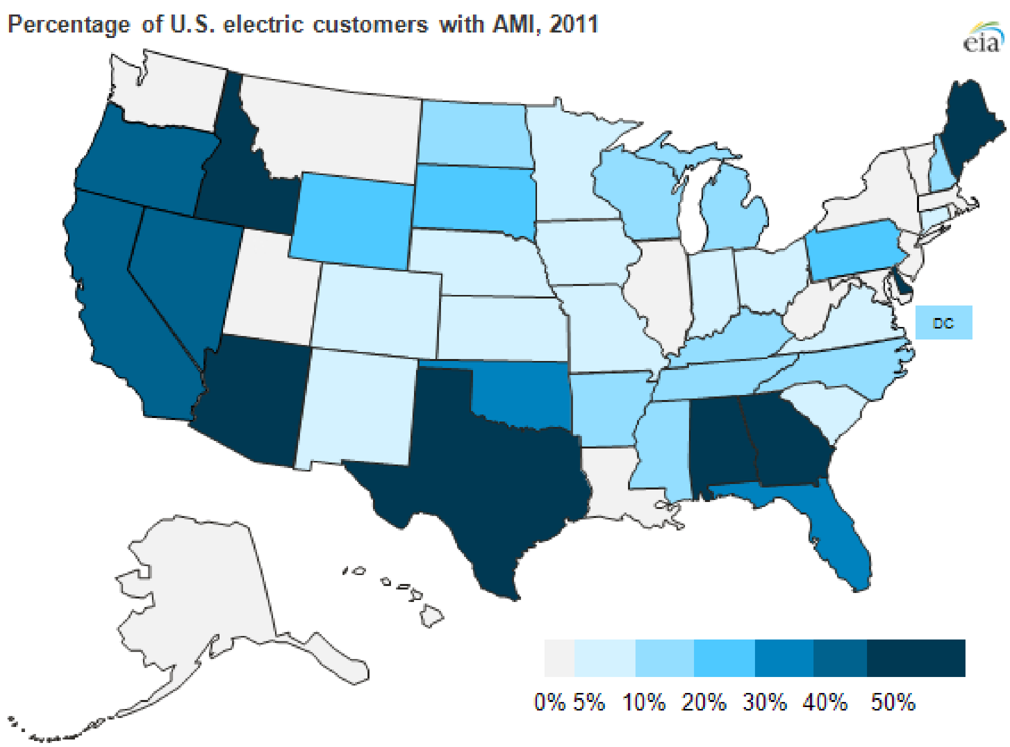
Recent advances in metering technology have dramatically increased the functionality of power meters. As a recent Massachusetts Institute of Technology smart grid report put it:

> In [the] traditional paradigm, utility employees visit customer premises and manually read electromechanical watt-hour meters that measure electric energy consumption. These meters are no longer commercially available in the U.S., having been replaced by

[11] Xcel Energy, 2014 Annual Report, at page 24.
[12] Residential customers can also receive an additional 2% year-round discount for enrolling their electric water heater.

> solid-state electronic meters, though many electromechanical meters are still in use today. Electronic meters can more easily store and communicate energy consumption as a function of time. These new meters have enabled two distinct new approaches to data capture and management: automated meter reading (AMR) systems and advanced metering infrastructure (AMI) systems.[13]

As of 2012, one-third of the nation's more than 145 million electricity meters were Automated Meter Reading (AMR), and another 30% were Advanced Metering Infrastructure (AMI).[14] The distribution of AMI meters by state can be seen in the map below. Advanced meter adoption in Minnesota varies widely between utilities: OTP and IPL have virtually none, DEA has roughly 25% AMR and no AMI, and MP and Xcel have virtually all either AMR or AMI.[15] Before providing a more detailed description of utility metering technology, Staff provides a brief summary of AMR and AMI technologies.



AMR meters enable remote meter reading, most commonly through short-range radio signals.[16] AMR is often implemented by retrofitting older meters with devices that enable AMR, such as Encoder Reader Transmitters (ERTs). When ERTs are inserted into electromechanical meters, they emit radio signals that can be received by special hand-held devices. Utility meter-readers then collect usage data by driving

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[13] Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," at pages 132-133.

[14] U.S. Energy Information Administration, "Electric Power Annual 2012," December 2013.

[15] Many municipal and non-rate-regulated cooperative utilities have also installed smart meters, but, as none of them filed an Annual Report in 2014, they are not included in this discussion.

[16] AMR meters can also transmit usage data through wi-fi signals, landline telephone signals, or even through power lines.

near the meter and bring the data back to the utility to be downloaded; this can dramatically decrease the amount of time required to read meters. AMR can also allow for more detailed, reliable usage data.

AMI meters, also known as "smart meters," are capable of two-way communication, and they are typically able to record usage data in near real-time, reported in increments of an hour or less. AMI meters' two-way communications capability enables the possibility of dynamic pricing, in which rates would change in real time to track Midcontinent Independent Transmission System Operator (MISO) locational prices. Utility investments in AMI have been driven primarily by American Recovery and Reinvestment Act grants and/or state legislative or regulatory action.[17]

The operational benefits to utilities from AMI fall into four primary categories. First, the largest utility benefits come via reduced labor costs: remote meter reading and remote connection/disconnection can dramatically reduce the number of times utility personnel have to go to customer premises, and the ability to remotely detect customer connections can improve fault location, which reduces restoration costs. Second, AMI meters can improve billing and customer support: more accurate and timely billing improves utilities' cash flows, remote connection/disconnection increases accounting accuracy, and more accurate metering data can improve call center customer support. Third, AMI meters are also better at detecting energy theft or diversion, which increases utility revenues once addressed. And, finally, AMI meters can improve grid management: remote meter connection detection helps reduce outage breadth and duration, and cumulative metering data can be used by system operators to more effectively manage distribution assets.[18] In total, the U.S. Department of Energy's initial estimates show operations cost savings can vary widely, from "13 to 77 percent, depending on several factors including the status of legacy systems, integration issues, and customer densities per line mile."[19] Staff has heard from utilities and stakeholders that the benefits of smart meters are highly dependent on the population density of the utility's service area. In addition, benefits may also vary based on state requirements; for instance, the Commission's Rules prohibit remote disconnection, so remote disconnect functionality could not be included as a cost savings.[20] Thus, the degree to which a utility would benefit from smart meter additions is dependent on its particular circumstances.

But while operational benefits can be substantial, in some instances they may not cover the large up-front infrastructure investment costs. AMI installations require significant up-front costs, not just for the meters themselves, but also the IT and billing system upgrades necessary to realize their full benefits. Moreover, for most utilities, the largest single operational cost-saver of AMI is meter-reading automation; for utilities like Xcel that have relatively new AMR meters, installing AMI meters would likely have limited meter-reading cost reductions. A recent Massachusetts Institute of Technology review found that

[17] U.S. Department of Energy, "2014 Smart Grid System Report: Report to Congress," August 2014, at page 4.
[18] Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," at pages 133-134.
[19] U.S. Department of Energy, "Smart Grid Investment Grant Program Progress Report II," October 2013, at page viii.
[20] Minn. Rules 7820.2500 states, "Service may be disconnected only in conjunction with a personal visit by a representative of the utility to the address where the service is rendered…"

for utilities with newly installed AMR meters, operational savings from AMI "may offset half or less of the projected incremental cost of AMI deployment."[21]

In addition to operational benefits, AMI meters have many non-operational benefits that are often harder to quantify. AMI improves the capability for and effectiveness of time-varying rate designs, but only if utilities choose to offer them. AMI meters also provide customers with greater control over their energy use; this is especially true for residential customers with programmable thermostats or appliances, or for business or commercial customers with facility energy management systems. However, like reduced frequency and duration of outages, the bulk of these benefits flow to customers, not utilities; this, in combination with the difficulty in of quantifying these benefits, means these benefits are often not considered in utility cost-benefit analyses.[22]

DEA: Meters (pp. 3, 6-7)

Currently, 25% of DEA's meters are equipped with AMR technology. The vast majority (21% of all meters) achieve AMR through ERT modules, which transmit meter readings via radio signals. DEA has focused its ERT investments on hard-to-reach urban meters.

The remainder (4% of all meters) of DEA's AMR meters employ TURTLE TS1 technology. When a TURTLE module is installed into a meter, it is able to transmit the meter reading through the power line to a substation, where a collector device stores the readings. These modules have primarily been installed in rural meters.

In 2013, DEA performed a study on the costs and potential benefits of AMI installations. The report identified a number of potential benefits, but the company's 2014 Annual Report did not specify whether or not it plans to invest in AMI technology. In 2011, GRE received a U.S. Department of Energy grant to install and test a meter data management (MDM) system. MDM systems are necessary to harness the full potential of AMI and other smart grid investments.

IPL: Meters (p. 4)

IPL has not deployed AMR or AMI in Minnesota. However, the company has installed some advanced features to meters for some of its largest C&I customers. These 341 meters, which represent roughly 5% of IPL's Minnesota C&I customers, provide customers with greater access to data on energy usage, including the optional web-based interface PeakMap.

MP: Meters (pp. 3-4)

Virtually all of MP's meters are either AMR or AMI. As of the end of 2013, MP had installed roughly 24,000 AMI meters, nearly one fifth of the company's total meters. 8,030 of these AMI meters were

[21] Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," at page 134.
[22] Ibid.

installed as part of a U.S. Department of Energy American Recovery and Reinvestment Act Smart Grid investment Act, which provided half of the $3.1 million budget for the company's Smart Grid-AMI pilot project. The table below summarizes MP's metering technologies.

Equipment	Coverage	Description
Mechanical Meters	Less than 1%	Traditional electromechanical meter that records kWh usage.
AMR-Mechanical Hybrid	64%	Traditional Electromechanical meters that are retrofitted with a one-way electronic AMR module capable of reporting multiple quantities including kWh, kW, and outage count.
AMR-Solid State	17%	Modern Solid State electronic meters integrated with a one-way AMR module or retrofitted with an external AMR unit. Capable of reporting multiple quantities including kWh, kVARh, kW, and outage count.
AMI-Solid State	18%	Modern solid state devices integrated with a two-way AMI communication module. Capable of multiple measurement functions including TOU, kW, kWh, KVA, kVAh, kVAR, kVARh, instantaneous and average voltage, two channel load profile, and remote disconnect. Also capable of remote firmware, program, and display updates.

OTP: Meters (pp. 6-7)

At present, almost none of OTP's meters are either AMR or AMI. The company did not provide Minnesota-specific data, but across its three-state territory, it has 513 AMR meters, or 0.3% of its total meters. In 2014, the company plans to conduct a pilot program of 10 AMI meters. This pilot will "explore the reliability of cellular coverage for meter reading, understand the customer portal and tools related to usage, trial the head-end AMI and back-end Meter Data Management (MDM) systems, perform load management measurement and verification, and assess reliability measurement and reporting capabilities."[23]

Xcel: Meters (pp. 19-20)

Nearly all of Xcel's meters are equipped with AMR technology. According to the company, its AMR system has "resulted in reduced meter reading costs and resource requirements, and in most cases, more consistent meter reading performance as compared to manual meter reading."[24] The table to the right provides a more detailed description of Xcel's AMR deployment.

Service	Customer Class	AMR	Non-AMR
Electric	Residential	1,125,763	101
	Commercial	121,885	1,089
	Industrial	5,129	3,100
	Government	3,040	404
Gas	Residential	413,891	1
	Commercial	34,655	391
	Industrial	323	179
	Government	649	26
	Total	***1,705,335***	***5,291***

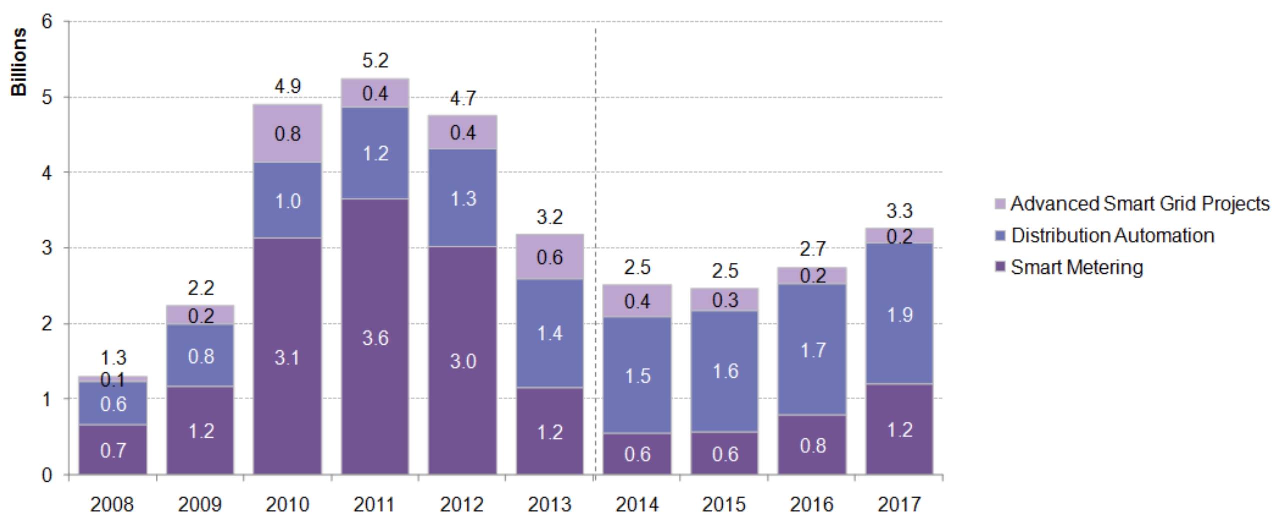
[23] OTP, 2014 Annual Report, at page 7.
[24] Xcel, 2014 Annual Report, at page 20.

Automation/Reliability/Security

Staff Comment

When it comes to the distribution system, smart grid investments typically focus on two main goals: improving reliability and operational efficiency. Nationally, electric customers experience an annual average of 1.5 to 2 power interruptions totaling 2 to 8 hours without power. In 2013, Xcel's Minnesota customers had an average of 0.88 power interruptions totaling an average of 93.73 minutes without power.[25] Nationwide, approximately 80% of power interruptions are attributable to faults on the distribution system.[26] Further, in Minnesota, 7.7% of energy generated is lost in transmission and distribution, considerably more than the national average of 6%.[27]

In recent years, utilities have invested considerable sums to improve reliability and operational efficiency on the distribution system. The chart below shows actual and projected smart grid investments in the US from 2008 to 2017.[28] As the chart displays, investments in distribution automation have increased steadily, and they are projected to account for the majority of smart grid investments in the near future.



The primary focus of the smart grid spending on distribution system improvements has been on technologies that monitor, communicate, and control distribution system operations. In the Department of Energy's words, when these technologies are integrated with existing distribution system equipment, they "enable new capabilities to automatically locate and isolate faults using automated feeder switches and reclosers, dynamically optimize voltage and reactive power levels, and monitor asset health to effectively guide the maintenance and replacement of equipment."[29] Before summarizing the utilities' reports on automation, reliability, and security, Staff first describes three types of smart grid investments that have

[25] Xcel Energy's 2014 Service Quality Report, filed April 1, 2014 in Docket No. 14-131.
[26] Ibid, at page 128.
[27] Loss statistics are averages from 1990 to 2012. Source: U.S. Energy Information Administration, "Minnesota Electricity Profile 2012, Table 10. Supply and disposition of electricity," May 1, 2014.
[28] U.S. Department of Energy, "2014 Smart Grid System Report: Report to Congress," August 2014, at page 3.
[29] Ibid, at page 7.

been made by one or more utilities in Minnesota: self-healing systems, voltage and volt-ampere reactive control, and phasor measurement units.

The first example of monitor-and-control technologies that improve reliability is automated, "self-healing" systems. Self-healing systems use circuit breakers, communication and control devices, and computer software to limit the scope and duration of outages. A recent Massachusetts Institute of Technology study provides a hypothetical example:

> [C]onsider an automobile accident that knocks down a pole supporting distribution wires, interrupting service to customers. A distribution system with software for automatic [self-healing] in place that also includes multiple feeders and sectionalizing switches—switches that divide lines into independent sections—can isolate the site of the fault (the downed wires), perform analysis to determine the extent of the damage and options for reconfiguration, and provide a secondary path for service to customers who would otherwise be without power.[30]

In addition to reducing operations costs, this process has the potential to dramatically increase reliability: Oklahoma Gas & Electric Company's self-healing network has reduced outage time by 54% to 70%.[31]

A second example of monitor-and-control technology that can improve operational efficiency is voltage and volt-ampere reactive or "volt/VAR" control. A primary function of the distribution system is to transform voltage from high-voltage transmission lines to the appropriate level for customer use. Many types of electronic equipment—such as computers, phones, and televisions—are designed to function within a relatively wide voltage range, but voltage levels above or below this range can lead to inefficient operation and reduced equipment life. Along distribution lines, voltages decline as customers draw power. This means that voltages will be higher near substations than they will be toward the end of the line. Utilities have long been able to control voltage to keep it in the acceptable range, but many utilities only monitor voltage at the substation, not on the line. In order to ensure that the voltage at the *end* of the line will still be within the acceptable range, conventional practice is to set the voltage toward the upper end of the range when it leaves the substation. The problem with this practice is load will draw more power at higher voltage levels.

Volt/VAR technology is employed to reduce power consumption by optimizing the voltage level supplied to customers. With volt/VAR, sensors are placed on distribution lines to measure voltage levels and report them to the substation. Control equipment in the substation is then used to keep the voltage at the lower end of the acceptable range. This process is illustrated in the figure below.[32] As the figure shows, volt/VAR control both reduces the average voltage level (the red line is below the blue) and tightens the variation along the distribution line (the red line is flatter than the blue line). Volt/VAR control can also be used to reduce peak loads: this practice, known as conservation voltage reduction, entails decreasing voltage to the lower end of the acceptable range during periods of high demand.

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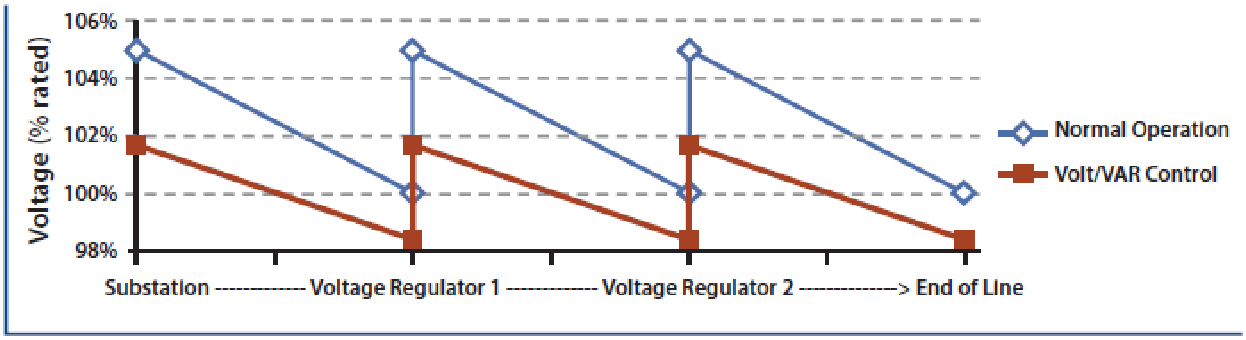
[30] Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," page 130.
[31] Ibid.
[32] Taken from: Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," page 132.

Figure 6.1 Voltage Profiles with and without Volt/Volt-Ampere Reactive (VAR) Control



When properly deployed, volt/VAR control can decrease energy consumption significantly without any change in customer behavior. Generally, volt/VAR technologies reduce energy consumption by 1% for every 1% reduction in voltage levels.[33] The Oklahoma Gas & Electric Company's review of volt/VAR control estimated that "installing volt/VAR control on 400 of their highest-priority circuits would save 106 gigawatt hours per year, or approximately 0.4% of their annual energy sales, and defer 80 megawatts of future generation on their existing capacity of 6,800 megawatts."[34]

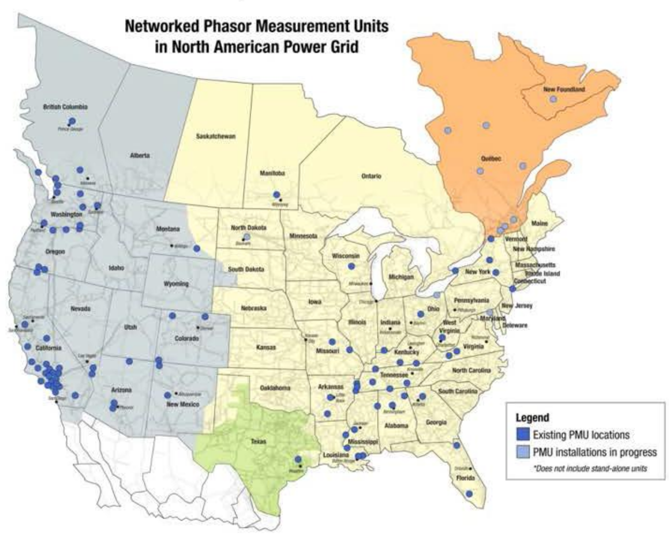
The third example of monitor-and-control technology that can improve operational efficiency are phasor measurement units (PMUs). Presently, most substations are equipped with supervisory control and data acquisition (SCADA) systems, which are specialized computer systems that monitor and control substation processes. SCADA systems collect information at remote terminal units (RTU), which are located at generators or substations. RTUs collect information on the status of circuit breakers and voltage, current, and power levels. This information is returned to the control center every several seconds. Control centers can then send commands back to RTUs, telling them, for example, to open or close a breaker. Utilities use SCADA systems for a wide variety of purposes, from turning capacitors on or off to manage reactive power levels on the distribution feeder, to identifying fault locations to dispatch crews to outage locations, to providing engineers with the information they need to perform load and operating analyses.

While a response time of only a few seconds may seem impressive, some power system phenomena occur in fractions of a second. Accordingly, some utilities and Regional Transmission Organizations (like MISO) have begun to implement synchrophasor technology, which employs PMUs. Like RTUs in SCADA systems, PMUs provide important data on voltage, current, and frequency at substations, but PMUs are much more powerful: where SCADA systems collect information every few seconds, PMUs return measurements 30 times per second or faster. Moreover, PMUs can be synchronized using GPS time signals, so that the data they provide are time-stamped; this allows for a real-time comparison of PMUs across a system. Comprehensive studies are preformed to select the most beneficial points for the placement of PMUs, allowing for extremely accurate, wide-area monitoring; when combined with known line characteristics, PMUs can calculate instantaneous power flows throughout an entire system. In short, if SCADA is an X-ray, PMUs are an MRI.

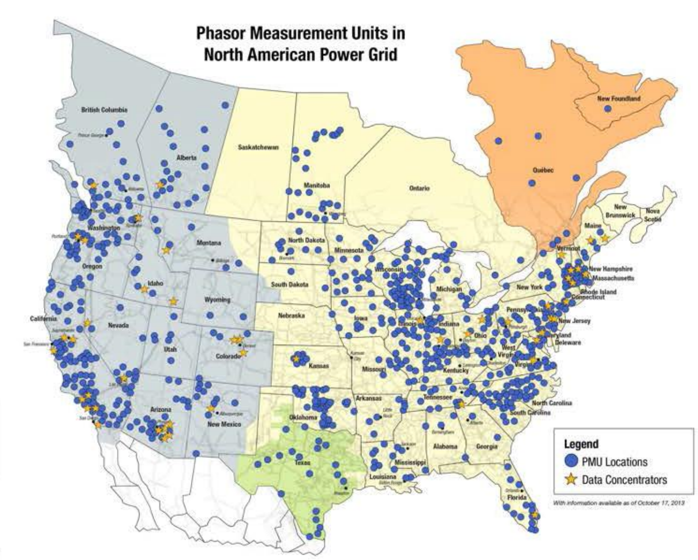
[33] U.S. Department of Energy, "Application of Automated Controls for Voltage and Reactive Power Management- Initial Results," December 2012, at page ii.
[34] Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," page 132.

Installation of PMUs has increased dramatically in recent years. The map below illustrates the rapid increase in synchrophasor coverage; in total, networked PMUs will increase from 166 in 2009 to over 1,000 in 2014-2015.[35] As the map below shows, several PMUs have been installed in Minnesota over this period. Through an American Reinvestment and Recovery Act project, MISO has installed 165 PMUs and 25 phasor data concentrators.[36]

April 2007



October 2013



One of the main benefits of PMUs is their potential to reduce the risk of wide-area blackouts. Sophisticated software programs have been developed to interpret large quantities of PMU data, giving grid operators the information they need to identify system instabilities and recognize when the system is exceeding acceptable operating limits, so that they can correct disturbances *before* they threaten grid stability. PMUs also offer additional benefits, such as improved system capacity and improving engineering models and simulations.[37]

DEA: Automation/Reliability/Security (pp. 4-6)

DEA has made several investments in monitoring and control technology. DEA's SCADA system extends to 100% of its substations. DEA is able to monitor and control 40-60 MW of member-owned

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[35] U.S. Department of Energy, "2014 Smart Grid System Report: Report to Congress," August 2014.

[36] U.S. Department of Energy, "Smart Grid Investment Grant Project Description: Midwest ISO Synchrophasor Deployment project," April 2012. Accessible online at https://www.smartgrid.gov/sites/default/files/pdfs/project_desc/09-0124-miso-project-description-04-02-12.pdf

[37] The information PMUs provide can allow system operators to safely bring the grid closer to its true stability limit, improving system capacity without expensive transmission investments and without increasing the risk of a blackout. For example, the Bonneville Power Administration will use PMU data to improve the capacity of the California-Oregon Intertie, which has system constraints that often force it to operate below capacity; once fully implemented, PMUs are expected to increase capacity by 30% (Massachusetts Institute of Technology (2011), "The Future of the Electric Grid: An Interdisciplinary MIT Study," page 4).

distributed generator capacity. The company's SCADA system also allows it to maintain tight VAR control, with feeder power factors typically within 0.5% of 100% power factor; this reduces system line loss and improves the power quality provided to customers. Moreover, in 2012, DEA initiated a pilot project to enhance voltage monitoring and control, putting automatic voltage regulators on distribution lines. The results were very positive, with the company reporting "better operational real-time awareness of system voltages, enhanced efficiencies and better fault locations."[38] In 2013, the company added remote monitoring and control to more sets of regulators, and it plans to continue adding this technology to additional regulators over the next several years.

DEA has also invested in reliability and security technologies. In 2012, the company completed a multi-year project to upgrade its Geographic Information System (GIS) and Outage Management System (OMS) systems. DEA now has digital maps of all of its physical distribution assets. This not only eliminates the need to maintain paper maps, it also aids the company's OMS. The OMS uses computer software to compile inputs from multiple sensors on the distribution system and outage calls from customers, which it uses to approximate the location of an outage.

IPL: Automation/Reliability/Security (pp. 4-5)

IPL has some SCADA capabilities in Minnesota, with systems deployed at a few of the company's larger substations. In addition, the company has self-healing capabilities on its 24KV sub-transmission system: faulted sections of circuits are identified and load is automatically transferred to alternate sources, which minimizes the magnitude and duration of outages.

MP: Automation/Reliability/Security (pp. 3, 5-8)

MP has made significant investments in outage management. MP has recently completed the integration of its OMS and AMI system. The new AMI meters now automatically provide "last-gasp" outage and "power on" restoration messages. The company also introduced applications to allow customers to report outages and check the status of outages on their smart phones. When combined with existing outage monitoring equipment on primary lines, these additions allow the company to more precisely approximate the location of faults. MP is also continuing its line panel project, which replaces particular 115kV line panels at key substations and installs software that "improves grid intelligence and enhances cyber security."[39]

MP has also been a participant in MISO's Synchrophasor Project. As of 2013, MP had installed four PMUs and two Phasor Data Concentrators, which compile PMU data from MP and send it to MISO.

MP also recently deployed its first self-healing network on its distribution system between two critical substations in the Duluth area. The network, which was funded in part through a U.S. Department of Energy grant, uses advanced switches and reclosers that communicate through a fiber optic connection. The switches are programmed to isolate a fault and automatically redirect load. The system has already

[38] DEA, 2014 Annual Report, at page 5.
[39] MP, 2014 Annual Report, at page 5.

passed its first major test: in the spring of 2013, there was a major event on the system that would have knocked out power to approximately 2,800 customers for several hours. The automation system isolated the fault and restored power to roughly 70% of effected customers almost instantaneously. In the company's words: "The upgraded system operated exactly as designed and provided the restoration benefits that Minnesota Power projected given the catastrophic nature of the Distribution Feeder event."[40] But as well as the technology worked, it is expensive, and the company does not currently plan to deploy it system-wide.

OTP: Automation/Reliability/Security (pp. 7-10, 12-13)

Like MP, OTP has been taking part in MISO's Synchrophasor initiative. From 2010 through 2014, OTP installed PMUs at a total of 13 substations across its system. The company has also had protective relays on its transmission lines since the mid-1980s. These relays provide information on faults, considerably enhancing fault location.

OTP has made several additional investments to improve reliability. In mid-2004, the company began installing an Interruption Monitoring System, which installed monitoring devices on each of the company's 725 distribution feeders. The company also recently completed converting nearly 4,000 maps from AutoCAD to GIS. Ultimately, OTP plans to integrate these GIS maps into a single, interactive system-wide map. The company believes this will "enhance communication with employees and customers, leverage existing data systems to track and manage the Company's assets more efficiently, and provide geo-spatial information of the Company's assets along with related attributes and detail."[41] And, in 2012, OTP initiated a three-year fleet tracking pilot project, in which it installed tracking devices on 39 company vehicles. The goal of the program is to enhance reliability by optimizing dispatch decisions.

Xcel: Automation/Reliability/Security (pp. 3-18)

Xcel has a number of automation, reliability and security projects in the works, covering a wide variety of technologies and objectives. To aid the reader, Staff has divided them into four subcategories.

Network Communications Strategy (pp. 3-5)

One of the main smart grid projects on the horizon for Xcel is the implementation of its Network Communication Strategy, or, "the Strategy." The goal of the Strategy is to ensure that the company is able to handle its ever-increasing data needs. Broadly, Xcel's Strategy is to funnel field data through "hubs," which then relay the data to a central system. The hubs will be the nearest substation (for electric) or pressure regulator (for natural gas). The company believes the hubs will "facilitate decisions and actions closer to where the system conditions and events are occurring in the field," which will become necessary as the hubs become more intelligent.[42] As the company explains: "[I]n the future, and particularly with greatly expanded DG on the system, it will be essential for the system to make decisions

[40] Ibid, at page 8.
[41] OTP, 2014 Annual Report, at page 13.
[42] Xcel, 2014 Annual Report, at page 4.

much closer to the conditions occurring in the field. This is necessary in order to respond in a secure and appropriate manner that protects the rest of the system."[43]

Xcel plans to implement its Strategy incrementally. The first step is the introduction of a Network Operations Center, which is a central point of control for operational communications. Currently, the company has several networks, each "optimized for a particular environment (electric SCADA, gas SCADA, device monitoring, etc.)"[44] Next, the company will focus on increasing communications with its hubs. By implementing its Strategy incrementally, Xcel hopes to moderate the up-front cost impact of the project.

Once fully implemented, Xcel expects the Strategy to:

> [Improve] efficiency through increased standardization, monitoring and remote control of our system in a secure manner. For example, we expect to consolidate existing field area networks, and leverage our substations as communications hubs, aggregating data from field devices; this reduces the number of separate networks that must be monitored and maintained.[45]

System Monitoring and Control (pp. 6-9)

Xcel's planned monitoring and control investments are focused on two concurrent programs: its Energy Management System (EMS) and its Advanced Distribution Management System (ADMS). The primary function of Xcel's EMS is the SCADA element. Xcel plans to replace its EMS, which was installed in the mid-1990s, because "[t]he level of customization we have had to do to the system to meet the changing transmission regulatory environment and market structure has undermined the system's reliability, and caused Critical Infrastructure Protection compliance and security challenges."[46] The company has been testing the replacement EMS, General Electric's PowerOn Advantage EMS, which it plans to implement in early 2015. According to Xcel, this new EMS "contains many enhanced functional improvements in the basic SCADA function, and improved support for advanced application functions that standardize Operator capabilities and approach, as well as adding additional functionality regarding circuit management."[47] Xcel has also been a participant in MISO's synchrophasor project, with 50 PMUs in 17 substations in its Minnesota territory.

Xcel's second planned monitoring and control project is called ADMS. ADMS will complement the EMS, integrating with the SCADA system in order to enhance its functionality. Whereas SCADA systems function at the substation level, ADMS will extend the monitoring and control capabilities onto distribution lines at select locations. The two applications enabled by ADMS that Xcel believes will have the greatest financial benefit are self-healing distribution systems and volt/VAR optimization. The company calls its self-healing capabilities "FLISR," which stands for fault location, isolation, and service restoration. Staff assumes this system will function similar to MP's self-healing network described on

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[43] Ibid.
[44] Ibid.
[45] Ibid, at page 5.
[46] Ibid, at page 6.
[47] Ibid.

pages 16 and 17 above.[48] Xcel's volt/VAR optimization, which it refers to as Integrated Volt VAR Optimization, will reduce system losses and allow the company to reduce system load during emergencies or periods of peak demand.[49]

Once fully implemented, Xcel expects a panoply of benefits from its ADMS, including:

> [R]eliability improvements such as faster restoration times, improved storm response and restoration, and improved outage and restoration information; power quality monitoring to quickly identify problems and maintain compliance and equipment performance; safety measures such as ensuring distributed generation isolation during outages, decreases in drive time and avoided trips, and improved tagging and switching management; operational efficiencies such as reduced fault investigation time, reduced crew time for fault location, isolation and restoration, improved situational and operational awareness, and optimized switching; conservation and energy efficiency, such as reduced peak demand and reduced electrical losses; and, asset optimization such as improved analytics and remote diagnostics of intelligent equipment.[50]

High Definition Survey and Line Modeling (pp. 11-12)

Xcel is in the process of surveying its entire transmission system using a Light Detection and Ranging (LiDAR) process, in which helicopters fly along transmission rights-of-way using sensors to capture orthographic images (like those in Google Earth) and oblique images (like those in Google Street View). Xcel uses these images to "verify electrical clearances, respond more quickly to storm damage, order materials, and design new construction, which reduces costs and improves reliability of the system."[51]

LiDAR provides three main advantages over traditional ground surveying. First, it provides larger, higher-quality images. A single aerial pass can capture a 300-foot swath, a much larger area than ground surveying, which typically only covers a 50- to 100-foot width. Second, LiDAR is much faster. Traditional surveying is a slow process, requiring coordination with several landowners; a single helicopter can survey 30-60 miles of transmission lines in a day, a distance that would take months to survey using the traditional ground approach. Third, and perhaps most important, LiDAR is much less expensive: in 2013, Xcel's cost-per-mile for LiDAR surveying was only $800, well below the traditional ground surveying cost of $2,000. The company estimates LiDAR saved it $1.4 million in 2013 alone. To date, the company has acquired LiDAR surveys of roughly 3,250 of its 4,000 miles of transmission lines in the state.

Outage Time Reduction (pp. 9-10, 15)

Xcel has several technologies in place that aim to reduce outage time following faults. In 2012, Xcel completed an upgrade of its OMS that allowed the company to use its AMR meters to determine whether or not a customer is receiving power. The company is able to "ping" the meter "by accessing a field

[48] Xcel has another technology that is akin to FLISR: while not completely "self-healing," the company has 74 "Automatic Switch Teams" in Minnesota that use automation to restore service to as many customers as possible following an outage. More information can be found in the "Automated Switch Teams" section, beginning on the bottom of page 14 of the company's 2014 Annual Report.

[49] Xcel also has a "SmartVAR Management" pilot program, which is described in more detail on page 16 of the company's 2014 Annual Report.

[50] Xcel, 2014 Annual Report, at page 11.

[51] Ibid, at page 11.

controller that is part of our AMR system, which polls the individual customer's meter to determine whether it is energized."[52] In 2013, these "pings" allowed the company to avoid over 1,000 crew trips that would otherwise have been found "okay on arrival."

Another technology with a similar aim is Remote Fault Indication. As the company explains: "These devices identify high current flow, indicating that there is a fault downstream of the device, which then uses a cellular phone to report that it has seen fault current pass through it."[53] System operators can use this information to more accurately estimate the location of the fault, which reduces the amount of time spent physically patrolling distribution or transmission lines. Xcel has 125 of these devices in use in Minnesota.

Access to Customer Information

As the U.S. Department of Energy notes, "the availability of this personal electricity usage data has raised consumer concern over privacy and protection of their individual data."[54] Access to customer information is a broad topic, but for the purposes of these reports, Staff only considers customers' access to their own information.

IPL: Access to Customer Information (pp. 6-9)

IPL has 341 meters with advanced functionality installed in Minnesota, primarily for its largest C&I customers. These customers also have access to a web-based interface called PeakMap. With this program, customers have access to nine interactive graphs and two reports, with up to 24 months of historical usage data available. However, there are currently only 3 customers in Minnesota who utilize PeakMap. The company is in the process of implementing the Oracle Utilities Customer Self-Service functionality, which will provide all customers with online energy usage data; once this has been implemented, the company plans to retire its PeakMap system.

MP: Access to Customer Information (p. 7)

In 2012, MP initiated a TOU rate with Critical Peak Pricing pilot project. The program includes a web portal that "enables customers to view their usage information in monthly, daily and hourly increments," and will offer customers more frequent and in depth information about their energy usage.[55]

OTP: Access to Customer Information (pp. 8, 10-12)

OTP offers interactive customer usage software to both C&I and residential customers. One option is Power Profiler, a fee-based online program used primarily by C&I customers. The software provides

[52] Ibid, at page 9.
[53] Ibid, at page 15.
[54] U.S. Department of Energy, "2014 Smart Grid System Report: Report to Congress," August 2014, at page 6.
[55] MP, 2014 Annual Report, at page 7.

nine different reports, with very granular usage data (intervals as small as 15-minutes). OTP's larger customers have found this to be "valuable to identify and reduce demand peaks by fine-tuning equipment operation and altering work schedules."[56]

OTP's residential customers have two additional usage data tools options. The first is Bill Analyzer, which is available through the company's website. This tool takes a customer's inputs—such as home size, appliances, living habits, and usage history—and compares the customer's usage to others with similar homes and lifestyles, in order to help customers understand how they may be able to reduce their bills. In 2013, customers who used Bill Analyzer saved an average of 715 kWh per year, or four percent of their total usage. The second conservation tool available to residential customers is Opower's Home Energy Reporting System. This program, which is part of the company's Conservation Improvement Program, uses "a software platform that combines energy usage data with customer demographic, housing, and geographic information data to benchmark energy use and develop specific, targeted recommendations that educate and motivate consumers to reduce their energy consumption."[57] These reports are then sent out through the mail to selected customers. In 2013, over 33,000 reports were sent out in Minnesota, with program participants saving an average of 144 kWh.

Xcel: Access to Customer Information (pp. 20-24)

Xcel's residential and small business customers have access to a number of services online. Xcel's website features the My Energy portal, in which customers can access up to five years of monthly billing data and see how they compare to other, similar customers. The company's website also provides outage information, with maps that provide "aerial pictures, a legend indicating the number of customers impacted, and other detailed information to aid customers and the media in understanding the scope and scale of outage events."[58] In 2012, Xcel launched a mobile website for smart phones, which includes the full website's most commonly used features.

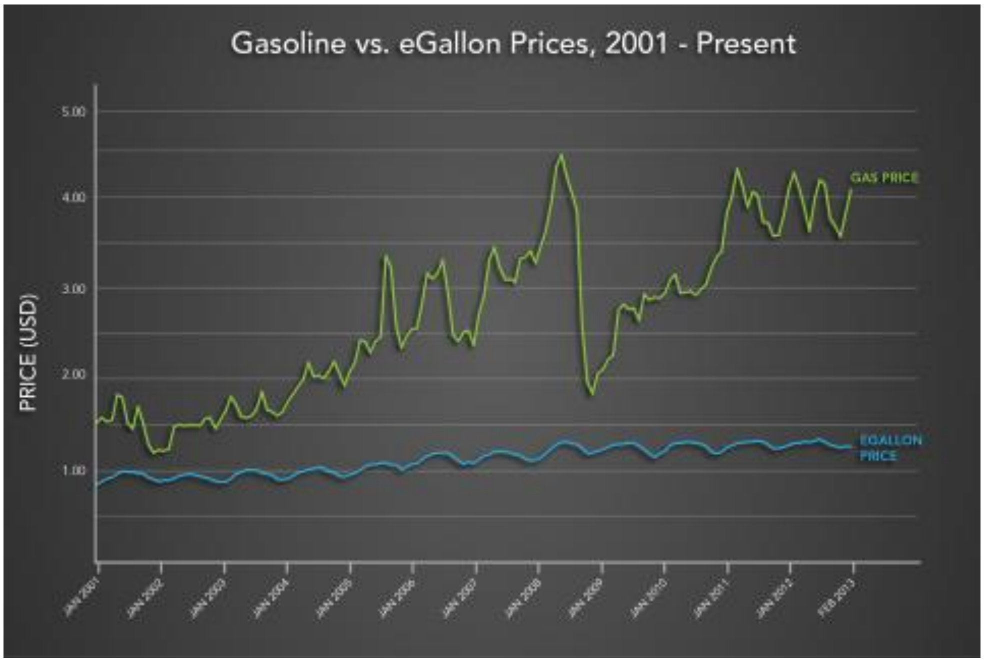
Another online resource was made available in 2013, when Xcel transitioned its Energy Feedback pilot program into a full program. The tool functions like an online audit: customers receive "usage analysis that evaluates equipment and savings suggestions similar to an online audit. This tool encourages goal setting and tracks action customers take to save energy and how they are performing against goals."[59] The program, which is available for both gas and electric customers, did not meet its savings goals in 2013; on page 23 of its 2014 Annual Report, the company provides several possible explanations.

Electric Vehicles

Though electric vehicles (EVs) are primarily a niche product in Minnesota today, their costs are falling rapidly, which could lead to increased purchases in the near future. Technological advances have reduced battery costs—which are typically the highest cost component of an EV or hybrid—by 50 percent in the

[56] OTP, 2014 Annual Report, at page 8.
[57] Ibid, at pages 11-12.
[58] Xcel, 2014 Annual Report, at page 21.
[59] Ibid, at page 22.

last four years.[60] In addition, Tesla Motors recently began construction of a $5 billion battery factory, which the company believes will reduce battery costs by an additional 30% solely through economies of scale.[61] Moreover, EVs also cost much less to fuel than gasoline-powered vehicles: In Minnesota, the electricity required to drive an EV the same distance as a gallon of gas (the "eGallon" price) costs on average $1.21, or roughly a third of the price of a gallon of gas.[62] And as the graph below displays, eGallon prices have climbed more slowly than the cost of gasoline over the last decade:



Expanded EV penetration provides an extraordinary opportunity for electric utilities. As the Edison Electric Institute concluded in a recent report:

> Stagnant growth, rising costs, and a need for even greater infrastructure investment represent major challenges to the utility industry. To maintain our critical energy infrastructure while investing for the future, today's electric utilities need a new source of load growth—one that fits within the political, economic and social environment.
>
> Electrification of the transportation sector is a potential "quadruple win" for electric utilities and society, and will enable companies to support environmental goals, build customer satisfaction, reduce operating costs and assure the future value of existing assets.[63]

[60] U.S. Department of Energy, "The History of the Electric Car," September 15, 2014. Accessed September 19, 2014 from http://energy.gov/articles/history-electric-car
[61] Wald, Matthew, "Nevada a Winner in Tesla's Battery Contest," *New York Times*, September 4, 2014.
[62] U.S. Department of Energy, "The eGallon: How Much Cheaper Is It to Drive on Electricity?," June 10, 2013.
[63] Edison Electric Institute, "Transportation Electrification: Utility Fleets Leading the Charge," June 2014, at page 3.

To be sure, incorporating a larger penetration of EVs onto the electric grid would also present considerable technical challenges to utilities. At the same time, however, expanded EV use offers many potential benefits: utility control over EV charging could be used "to delay charging to avoid local or system-wide peaks or absorbing excess solar and wind power to better integrate it into the grid."[64] In addition, TOU rates or special EV charging tariffs could encourage customers to shift charging to nights and weekends, increasing utilities' load factor. To aid the integration of EVs, the Electric Power Research Institute has been working with automakers and utilities to develop standardized charging technologies, which would make it both easier and less expensive for utilities to integrate the EV chargers on their system into a single grid command system.[65]

DEA: Electric Vehicles (p. 12)

GRE has worked with its member distribution cooperatives, such as DEA, to encourage off-peak charging for electric vehicles. DEA recently received Commission approval for a TOU rate for residential electric vehicles as a two-year pilot program. DEA will evaluate the new rate over the pilot period and then either "modify the rate as an on-going service offering or [discontinue] the pilot."[66]

Xcel: Electric Vehicles (pp. 28-31)

In 2011, Xcel convened a "Repowering Transportation" team made up of representatives from various positions within the company, tasked with "developing and implementing a comprehensive strategy to address clean transportation issues."[67] The company has also been an active member of Drive Electric Minnesota, a partnership between private, non-profit, and governmental entities aiming to increase utilization of EVs and expanding charging station infrastructure.

Xcel believes its generation and transmission capacity is capable of meeting additional demand due to increased EV penetration, even under optimistic adoption scenarios. The company does note, however, that there could potentially be issues with the distribution system if EV adoption is geographically concentrated in "clusters." The company has reached out to automakers to "gather information on the geographic location of EVs for planning and mitigation of system impacts," and it plans to "continue to closely monitor and manage transformer loading and other system impacts stemming from the incremental load from EV charging."[68] Xcel has also been marketing its TOU rate to EV owners to encourage off-peak charging, which would soften the impact of increased load on the distribution system.

[64] St. John, Jeff, "Networking and Aggregating EVs With a Universal EV-to-Grid Control Platform," *Green Tech Media*, July 29, 2014.
[65] Ibid.
[66] DEA, 2014 Annual Report, at page 12.
[67] Xcel, 2014 Annual Report, at pages 28-29.
[68] Ibid, at page 30.

Distributed and Renewable Resources

Each electric utility is required to file an annual report on the number of Distributed Generation facilities that have been added and removed from its system. The 2014 reports—summarizing the 2013 calendar year—were filed in Docket 14-10; the five rate-regulated utilities' filings are summarized in the table below.[69]

Utility	2013 Additions	Removals	Pending	Utility Total
DEA	5 (5 solar)	0	0	43
IPL	3 (3 solar)	1	2	54
MP	17 (16 Solar, 1 wind)	0	4	-
OTP	3 (1 biomass, 1 solar, 1 wind)	0	2	-
Xcel	120 (101 solar, 13 diesel, 3 methane, 2 natural gas, 1 wind)	0	10	1,185

DEA: Distributed and Renewable Resources (p. 8)

The distributed resources on DEA's system fall into two categories: standby generators on the company's C&I Interruptible Rate, and renewable resources (wind and solar). As of 2013, there were 220 members with C&I interruptible accounts. These members allow DEA to monitor and control their standby facilities in order to manage overall load, respond to transmission or distribution constraints, and to reduce wholesale market purchases during peak periods. In total, these facilities allow DEA to reduce system demand by 60 to 80 MW.

As of 2013, there were a total of 43 distributed renewable generation facilities interconnected to DEA's system: 195 kW from 9 wind generators and 264 kW from 34 solar generators. According to the company, its distribution system facilities are "adequate to support an increasing number of distributed generation interconnections."[70]

Xcel: Distributed and Renewable Resources (pp. 10-13, 18-19)

Xcel has initiated a number of research and pilot programs aimed at improving the integration of wind and solar onto the company's system. One example is the company's 2012 Solar on Network pilot program. Utilities commonly use secondary network distribution systems to provide maximum reliability to congested areas like downtown districts of large cities. Because reliability is at a premium on these networks, many utilities have forbid interconnection of distributed resources like solar PV on these networks; as Xcel explains, "The control systems for these networks rely on power flowing toward the customer, a state that can be reversed with distributed generation."[71] In 2012, Xcel initiated a pilot

[69] Utilities are only required to file additions and removals in these filings; some utilities chose to include the total number of DG facilities on their system, while others did not.
[70] DEA, 2014 Annual Report, at page 8.
[71] Xcel, 2014 Annual Report, at page 10.

program that approved solar installations on two of its networks—one each in downtown Minneapolis and St. Paul—albeit with very cautious technological requirements. The results of the pilot program were very positive, to the point where the company has slightly relaxed the requirements for future installations on its networks.

Xcel has also initiated multiple energy storage pilot programs, including the Solar-to-Battery program, the Community Energy Storage project, and the Wind-to-Battery system. These small pilot projects "aim to discern the technical and economic costs and benefits of utilizing energy storage" to attenuate the intermittency issues presented by renewable resources such as solar and wind.[72] A more detailed description of the projects can be found on pages 11 (Solar-to-Battery and Community Energy Storage) and 18 (Wind-to-Battery) of Xcel's 2014 Annual Report.

Another example of an investment Xcel has made in integrating renewable resources is the Advanced Wind Production Forecasting System. In 2009, Xcel entered into a research and development partnership with the National Center for Atmospheric Research. The result of the partnership was WindWX, which the company describes as "one of the most advanced wind-production forecasting systems in the world."[73] In 2013, the company completed two years of operations with WIndWX, and the results have been impressive: the company estimates the forecasting system has reduced forecasting error by over 40%, with an estimated savings for Minnesota customers of $15.4 million. On the basis of this success, the partnership "initiated a third phase of project work … to improve short-term forecasting, focusing on ramping and extreme weather events, and introducing probabilities into the forecasting process."[74]

[72] Ibid, at page 11.
[73] Ibid, at page 13.
[74] Ibid.