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Xcel Energy			
Docket No.:	E002/M-17-776		
Response To:	MN Public Utilities Commission	Information Request No.	4
Requestor:	Hanna Terwilliger, Michelle Rosier, Tricia DeBleeckere		
Date Received:	December 21, 2017		

Question:
Did the company or a third party perform a cost benefit analysis or business case analysis of FLISR, FAN, and/or AMI? Has a rate impact analysis, system study, or other analysis been conducted on these investments for Xcel's system? If so, please provide any of the reports and supporting documentation. If not, please explain why.

Response:
We have completed various analyses for FLISR, the FAN, and AMI, which we discuss below.

Field Area Network
The Field Area Network (FAN) is a key foundational component of our Advanced Grid Intelligence and Security (AGIS) initiative that will enable us to flexibly add functionalities that deliver system and customer benefits – even as technology and our customers evolve over time. The FAN is a communications network that is necessary to enable the "smart" devices in the field that provide benefits to the Company's distribution system and its customers As such, the FAN provides benefits through the programs and technologies it enables, rather than as a standalone system.

As an enabling technology, the FAN must be examined in the context of the particular functionality, or set of Company and customer benefits that it enables. Therefore, in this response, we discuss the FAN and its qualitative benefits generally; any consideration of benefits versus costs must be considered in combination with the specific additional functionality (e.g., FLISR, AMI, or other future functionality) it supports.

Qualitatively, the FAN's design, along with that of our existing Wide Area Network (WAN) will provide a highly reliable and redundant communications network. It is a standards-based network solution that conforms to IEEE standards – which provides important flexibility, in that it is vendor-neutral and ensures interoperability of components. The FAN is scalable – meaning, the FAN infrastructure will grow to support additional functionalities as they are approved over time – balancing our level of investment with the benefits the additional functionalities are expected to deliver to our customers and our operations. This approach affords flexibility to add functionalities as technology advances and our customers' expectations evolve, and the opportunity to pause before taking the next step in building on our AGIS foundation.

The combination of the FAN's Wi-SUN mesh and WiMAX networks will enable substations to communicate with all of the field devices and, through the WAN connection, will allow the back office applications to send commands to those field devices. The FAN enables the Company to monitor and manage events occurring on the grid in a more timely manner by supporting the ability to deploy computing capability closer to the field devices (for example, in substations).

The FAN's redundancy will also facilitate overall dependability of communications. For example, if a device fails on the Wi-SUN network and can no longer communicate, the mesh-type 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 going offline the mesh nodes will still be able to route communications through a different access point and WiMAX base station. The redundancy provided by the FAN will enable endpoint devices to continuously communicate both with each other and with head-end systems.

The FAN, in combination with AMI, will not only pave the way for exciting and novel functionality, it will also ensure the Company can continue to read customer meters and provide accurate customer bills –requirements under the Commission's Rules.[1] Beyond forming this important foundation, it will allow for customer consumption data to be collected at more frequent intervals, among other things. We outline potential additional or enhanced customer and system functionalities in our response to MPUC Information Request No. 5.[2]

[1] Minn. R. 7820.3400

[2] As we implement additional advanced grid functionalities, the FAN infrastructure will need to increase accordingly to appropriately handle the additional devices and data.

The FAN's capital items will be composed of its network infrastructure, including costs for hardware, installation, and project management, as well as preparation (or make ready). To support AMI, the hardware devices will be installed at locations that will enable them to communicate with the modules located in the AMI meters throughout our service area.[3] Because the AMI meters will be located at every customer premise, there will be a substantially larger number of these devices than of the intelligent field devices located on feeders that will implement FLISR. As such, AMI deployment will require a substantial amount of FAN equipment and devices to ensure the reliability and performance of the network. Costs will include the devices themselves, staging and delivery, installation and testing, and finally turn-up of the RF mesh with the other devices in each deployment area.

Fault Location, Isolation, and Service Restoration (FLISR)

For FLISR, we have completed a value analysis of expected System Average Interruption Duration Index (SAIDI) customer reliability improvements, which we provide in our response to MPUC Information Request No. 2. We provide another view of estimated customer reliability impacts from our proposed implementation in our response to MPUC Information Request No. 3.

Advanced Metering Infrastructure

For AMI, we completed and submitted a cost benefit analysis for our Public Service of Colorado (PSCo) Operating Company's AGIS Certificate of Public Convenience and Necessity application. We previously submitted this in our Minnesota Alternative Rate Design docket (Docket No. E002/M-15-662), and provide it also as Attachment A to this response. Attachment A contains the Direct Testimony and Attachments of PSCo witness Mr. Samuel J. Hancock in Colorado Docket No. 16A-0588E; the PSCo cost benefit analysis is included as Attachment SJH-2 to Witness Hancock's testimony.[4] In the same Minnesota Alternative Rate Design docket, we also submitted a separate high-level, illustrative cost benefit analysis of an AMI implementation in Minnesota on April 18, 2016. We provide this illustrative cost benefit analysis filing as Attachment B to this response.

As is the case with any cost benefit analysis, the benefits are based on measurement of certain cost/benefit elements and predicting the outcome of these elements over a relevant time period, as applied to specific group of stakeholders. The stakeholders and cost/benefit elements for Colorado will differ from those in Minnesota, which

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[3] With respect to AMI, it is the FAN's Wi-SUN mesh network technology that will specifically support it. In addition to their metering function, the advanced meters will have embedded communication modules that will allow the devices to communicate as part of the Wi-SUN network. We estimate that the AMI meters themselves (and their communications modules) will make up over 90 percent of devices that will communicate as part of the mesh network.

[4] The CBA was updated in Rebuttal, however, the CBA initially provided in Witness Hancock's Direct remains representative.

will subsequently impact the calculation. Some of these differences include the fact that the PSCo application included two customer rate program proposals, and that Minnesota has a fixed, wireless network automated meter reading system, which is not the case in Colorado. Therefore, while the PSCo cost benefit analysis provides an estimate of AMI benefits that could be achieved with AMI, it is not directly transferrable to Minnesota. As we noted in our response to MPUC Information Request No. 1, we expect to be prepared to request certification for AMI in late 2018 – and at that time, we will have completed a cost benefit analysis specific to Minnesota to support our request.

We do not wish to leave the impression, however, that such analyses form the only, or even—at times—the primary justification for these projects. Stated another way, not all projects are selected on the basis of their performance under a cost-benefit analyses, and projects are frequently driven by non-quantifiable concerns even where a cost-benefit analysis exists. Whether or not we completed a formal cost-benefit analysis, costs for all of our major projects are managed through various measures, such as proper planning, vendor proposals and negotiations, and/or proper scaling, as appropriate for the individual project. In the case of our AGIS initiative that presently includes FLISR, AMI and the FAN to support them, each project would be minimally subject to the budget and IT governance processes described in Direct Testimony by Company Witnesses Mr. Gregory J. Robinson and Mr. David C. Harkness, respectively in our most recent multiyear rate case (Docket No. E002/GR-15-826.

Further, a cost-benefit analysis provides only an estimate of potential net costs or savings and does not guarantee any particular result. When planning for future budgets, we incorporate internal and external resource needs based on what resources, assets, and efficiencies, will exist at that time. Further, savings achieved through one project are often utilized to reduce costs or make resources available for other projects and work. Therefore, the quantitative benefits of a project are factored into our future budgets through overall planning measures, and not necessarily as a 1:1 savings associated with a specific project.

Preparer:	John D. Lee
Title:	Senior Director
Department:	Distribution Electric Engineering
Telephone:	(303) 571-3515
Date:	January 19, 2018

Xcel Energy®

414 Nicollet Mall
Minneapolis, MN 55401

September 16, 2016

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: PSCO - ADVANCED METERING INFRASTRUCTURE COST BENEFIT ANALYSIS
ALTERNATIVE RATE DESIGN
DOCKET NO. E002/M-15-662

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the Direct Testimony and Attachments of Public Service Company of Colorado (PSCo) witness Mr. Samuel J. Hancock, included as Hearing Exhibit 108 with PSCo's August 2, 2016 submission of a Grid Intelligence and Security Request for a Certificate of Public Convenience and Necessity (CPCN) to the Colorado Public Utilities Commission in Docket No. 16A-0588E.

We committed to providing the attached information in our advanced metering infrastructure (AMI) Cost Benefit Analysis filed April 18, 2016 in the present docket. Mr. Hancock's testimony for PSCo, included as Attachment A to the present filing, provides more specific quantification of the AMI costs and benefits to Xcel Energy, and will help inform the specific costs and benefits that could be experienced in Minnesota given existing equipment, Minnesota Rules, and rate structures. To review the complete CPCN petition, including the testimony of other PSCo witnesses referenced by Mr. Hancock, use the link below to access the CPUC's E-Filings site.

https://www.dora.state.co.us/pls/efi/EFI_Search_UI.search

Enter "16A-0588E" in the "Proceedings Number" field on the search screen, and then select "Search" to see all documents submitted in the docket to date.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Mary Martinka at mary.a.martinka@xcelenergy.com or (612) 330-6737, or me at amy.a.liberkowski@xcelenergy.com or (612) 330-6613 if you have any questions regarding this filing.

Sincerely,

/s/

AMY LIBERKOWSKI
DIRECTOR, REGULATORY PRICING & ANALYSIS

Enclosure
c: Service List

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE	))))))))))	**PROCEEDING NO. 16A-____E**

DIRECT TESTIMONY AND ATTACHMENTS OF SAMUEL J. HANCOCK

ON

BEHALF OF

PUBLIC SERVICE COMPANY OF COLORADO

August 2, 2016

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

* * * * *

RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE	**))))))))))**	**PROCEEDING NO. 16A-____E**

SUMMARY OF THE DIRECT TESTIMONY OF SAMUEL J. HANCOCK

Mr. Samuel J. Hancock is a Manager, Regulatory Project Management for Xcel Energy Services Inc. ("XES"). XES is the service company subsidiary of Xcel Energy Inc., the parent company of Public Service Company of Colorado ("Public Service" or the "Company"). In this position he is responsible for supporting various regulatory matters including competitive resource acquisition processes, new product design, economic analyses of existing and potential resource options, as well as other technical analyses for Xcel Energy's operating companies.

In his testimony, Mr. Hancock presents and explains the Company's quantitative cost-benefit model with respect to the components of the Advanced Grid Intelligence and Security ("AGIS") initiative that are the subject of the Company's application for a Certificate of Convenience and Public Necessity ("CPCN"). While Company witnesses Mr. Russell E. Borchardt, Mr. Chad S. Nickell, Mr. Wendall A. Reimer, and Mr. David C. Harkness support the individual forecasted costs and benefits of the Advanced Metering

Infrastructure (“AMI”) and Integrated Volt-VAr Optimization (“IVVO”) efforts, including the Field Area Network (“FAN”) components and supporting information technology (“IT”) and cyber security efforts associated with AMI and IVVO, Mr. Hancock explains how those quantitative inputs are utilized to provide an overall cost-benefit analysis. Mr. Hancock also supports the assumptions included in the model, and provides the results of an analysis the Company believes is a conservative representation of costs and benefits. He notes that although a cost-benefit model is one useful tool for evaluating the Company’s proposal, the AMI and IVVO programs present a number of qualitative benefits, such as increased safety and customer satisfaction, that cannot be quantified but are a necessary component of Public Service’s broader initiative to enhance customer choice, to support an advanced, more transparent grid, and to enhance demand side management (“DSM”) goals.

Mr. Hancock estimates that the AMI and IVVO investments will provide a combined net present value benefit/cost ratio to Public Service customers of approximately 0.85 based on current cost and benefit forecasts, before taking into account the qualitative benefits of AMI and IVVO and the overall need to bring the grid into the future. In doing so, Mr. Hancock supports the Company’s petition for a Certificate of Public Convenience and Necessity in this proceeding.

**BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO**

* * * * *

RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE	)	**PROCEEDING NO. 16A-____E**

DIRECT TESTIMONY AND ATTACHMENTS OF SAMUEL J. HANCOCK

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LIST OF ATTACHMENTS

GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	Meaning
ADMS	Advanced Distribution Management System
AGIS	Advanced Grid Intelligence and Security
AMI	Advanced Metering Infrastructure
AMR	Automated Meter Reading
ANSI	American National Standards Institute
BPL	Broadband over Power Line
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CBA	Cost-Benefit Analysis
CIS	Customer Information System
CMO	Customer Minutes Out
Commission	Colorado Public Utilities Commission
Company	Public Service Company of Colorado
CPCN	Certificate of Public Convenience and Necessity
CPCN Projects	AMI, IVVO, and the components of the FAN that support these components
CPE	Customer premise equipment
CRS	Customer Resource System
CSF	Cyber Security Framework
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DDOS	Distributed Denial of Service
DER	Distributed Energy Resources
DOS	Denial-of-service
DR	Demand Response
DSM	Demand Side Management
DVO	Distribution Voltage Optimization
EPRI	Electric Power Research Institute
ERT	Encoder Receiver Transmitter
ESB	Enterprise Service Bus
FAN	Field Area Network
FLISR	Fault Locate Isolation System Restoration

Acronym/Defined Term	Meaning
FLP	Fault Location Prediction
GFCI	Ground Fault Circuit Interrupter
GIS	Geospatial Information System
HAN	Home Area Networks
ICE	Interruption Cost Estimation
IDS	Intrusion Detection System
IEEE	Institute of Electrical and Electronics
IPS	Internet Provider Security
IT	Information technology
IVR	Interactive Voice Response
IVVO	Integrated Volt-VAr Optimization
kVAr	Kilovolt-amperes reactive
kVArh	Reactive power
kW	Kilowatt
kWh	Kilowatt hours
LTCs	Load Tap Changers
LTE	Long-Term Evolution
MDM	Meter Data Management
MitM	Man-in-the-Middle Attack
MPLS	Multiprotocol Label Switching
NCAR	National Center for Atmospheric Research
NOC	Network Operations Center
NPV	Net Present Value
O&M	Operations and Maintenance
OMS	Outage Management System
OT	Operational Technology
PTMP	Point-to-multipoint
Public Service	Public Service Company of Colorado
RF	Radio frequency
RFP	Request for Proposal
RFx	Request for Information and Pricing
RTU	Remote Terminal Units

Acronym/Defined Term	Meaning
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SGCC	Smart Grid Consumer Collaborative
SGIG	Smart grid investment grants
SIEM	Security Incident and Event Management
SVC	Secondary static VAr compensators
TOU	Time-of-use
USEIA	United States Energy Information Administration
WACC	Weighted Average Costs of Capital
WAN	Wide Area Network
WiMAX	Worldwide Interoperability for Microwave Access
WiSUN	802.15.4g Standard
Xcel Energy Inc.	Xcel Energy
XES	Xcel Energy Services Inc.

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO

*** * * * ***

RE: IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER GRANTING A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR DISTRIBUTION GRID ENHANCEMENTS, INCLUDING ADVANCED METERING AND INTEGRATED VOLT-VAR OPTIMIZATION INFRASTRUCTURE	**))))))))))**	**PROCEEDING NO. 16A-____E**

DIRECT TESTIMONY AND ATTACHMENTS OF SAMUEL J. HANCOCK

I. INTRODUCTION, QUALIFICATIONS, AND PURPOSE OF TESTIMONY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Samuel J. Hancock. My business address is 1800 Larimer, Denver Colorado 80202, Suite 1400.

Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT POSITION?

A. I am employed by Xcel Energy Services Inc. ("XES") as a Manager, Regulatory Project Management. XES is a wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy"), and provides an array of support services to Public Service Company of Colorado ("Public Service" or "Company") and the other utility operating company subsidiaries of Xcel Energy on a coordinated basis.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THE PROCEEDING?

A. I am testifying on behalf of Public Service.

Q. PLEASE SUMMARIZE YOUR RESPONSIBILITIES AND QUALIFICATIONS.

A. As a Manager, Regulatory Project Management, my duties include supporting various regulatory matters including competitive resource acquisition processes, new product design, economic analyses of existing and potential resource options, as well as other technical analyses for Xcel Energy's operating companies. A description of my qualifications, duties, and responsibilities is set forth after the conclusion of my testimony in my Statement of Qualifications.

Q. ARE YOU SPONSORING ANY ATTACHMENTS AS PART OF YOUR DIRECT TESTIMONY?

A. Yes, I am sponsoring the following:

- Attachment SJH-1: Summary of AMI/IVVO Cost-Benefit Analysis
- Attachment SJH-2: AMI Cost-Benefit Analysis
- Attachment SJH-3: IVVO Cost-Benefit Analysis
- Attachment SJH-4: CPCN Projects Cost-Benefit Analysis
- Attachment SJH-5: Brattle Group Elasticity Study

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present the Company's overall assessment of the costs and benefits of the programs for which Public Service is seeking a Certificate of Public Convenience and Necessity ("CPCN Projects"). I begin by presenting the Company's quantitative cost-benefit analysis, which consolidates and summarizes the quantifiable costs and benefits of the

Advanced Metering Infrastructure ("AMI") and Integrated Volt-VAr Optimization ("IVVO") programs, as well as the associated components of the Field Area Network ("FAN") and Information Technology ("IT") integration and security, which are included in this CPCN Projects Application.

I also support the costs and benefits of two particular aspects of the quantitative analyses: (i) the residential customer peak demand reduction and associated avoided capacity benefit associated with residential demand rates, which are enabled by AMI, and (ii) the potential improvements to our Saver's Switch program enabled through the two-way communication utilizing the FAN.

In addition, I explain that there are certain benefits of AMI and IVVO that cannot necessarily be captured by a cost-benefit analysis. While Company technical witnesses Mr. Chad S. Nickell and Mr. Russell E. Borchardt discuss these benefits in more detail, I provide context for these unquantified benefits and explain how they support this CPCN Projects Application.

II. COST-BENEFIT ANALYSIS OVERVIEW

A. Model Requirements

Q. PLEASE DESCRIBE PUBLIC SERVICE'S COST-BENEFIT MODEL IN THIS MATTER.

A. The cost-benefit model calculates the benefit-to-cost ratio of the portion of Public Service's advanced grid intelligence and security ("AGIS") initiative for which the Company is seeking a CPCN. Company witnesses Ms. Alice K. Jackson and Mr. John D. Lee discuss the broader AGIS initiative in more detail in their Direct Testimony. The benefit-to-cost ratio is set forth on a 2016 net present value ("NPV") basis, and evaluates the stand-alone costs and benefits of AMI and IVVO, respectively, incorporating the FAN and IT integration components specific to each program. Finally, the model evaluates the net present value of estimated costs and benefits for AMI and IVVO (including associated FAN and IT costs) on a combined basis.

Q. HOW DID PUBLIC SERVICE STRUCTURE THE COST-BENEFIT ANALYSIS PRESENTED IN YOUR TESTIMONY?

A. The model compares the upfront and ongoing costs against the benefits of the Company's proposed project over the analysis period, which is 2016 through 2035 with primary implementation occurring through 2021. The model views costs and benefits from the customer perspective, meaning that it quantifies the estimated net impact of costs and savings to customers. 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, Public Service estimated meter installation costs as they would be included in rates.

We also estimated reasonably quantifiable direct-to-customer benefits of improvements in the Company's electric service that would not be incurred by the utility or directly affect customer rates. For example, an electrical outage has a direct impact on the customers' own activities, which can be measured through a "customer minutes out" ("CMO") metric.

Q. WHY IS THIS THE APPROPRIATE BASIS ON WHICH TO EVALUATE THE QUANTIFIABLE ASPECTS OF PUBLIC SERVICE'S CPCN PROJECTS APPLICATION?

A. By developing the model from the customer's perspective, Public Service is providing clear and comprehensive information about the overall impact of these programs to customers. The cost-benefit model also provides both a "high level" look at the costs versus the quantifiable benefits of AMI and IVVO for customers, as well as a more detailed breakdown of individual cost and benefits assumptions for each program. While not all reasons for undertaking the AGIS program or benefits of the program are quantifiable, the cost-benefit model provides an appropriate perspective on quantifiable considerations.

Q. PLEASE DESCRIBE THE PERIOD OF TIME THE MODEL EXAMINES.

A. The model examines the period beginning 2016 and ending 2035, beginning with early phase work to develop the AGIS initiative through a reasonable useful life of the AMI meters.

Q. WHY DOES THE MODEL EXAMINE THIS PERIOD OF TIME?

A. This twenty-year period for examination is well within the expected useful life of the AMI meters being deployed, and is also consistent with the industry standard for life cycle evaluation of similar projects. Although the vast majority of AMI meters being deployed are likely to continue to function beyond 2035, the twenty-year analysis period strikes a reasonable balance between a complete life cycle analysis of the meters being deployed, and a shorter forward-looking period wherein the Company has a higher degree of confidence in both the costs and benefits being quantified.

Q. HOW DID PUBLIC SERVICE DEVELOP THE COST AND BENEFIT INPUTS INTO THE MODEL?

A. The capital and Operations and Maintenance ("O&M") costs and benefits of AMI and IVVO, including the associated FAN and IT components, were determined by our metering, Business Systems and Distribution areas, as discussed in more detail below. These individuals further worked with our capital asset accounting group to ensure costs were properly categorized as capital or O&M, as applicable. I worked with these individuals and groups to coordinate these project planning efforts and to develop modeling assumptions consistent with the technical witnesses' cost and benefit estimates. The testimonies of the technical witnesses provide detail regarding the cost and benefit assumptions for each component of the CPCN Projects, while I summarize those model inputs and provide further explanation on the overall results of our cost-benefit analyses.

Q. CAN YOU PROVIDE MORE DETAIL AS TO HOW THE FAN COMPONENTS ARE INCORPORATED INTO THE MODEL?

A. Yes. As Company witnesses Mr. Lee and Mr. Wendell A. Reimer discuss in more detail 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. As such, the FAN will address the need for increased communication capacity that arises from the AGIS initiative, while also ensuring that the data being transmitted is secure. However, the FAN is not a standalone program that provides benefits in its own right; rather, it is the communications network necessary for AMI and IVVO to function and to provide their respective benefits to customers. Further, certain aspects of the FAN are specifically necessary to support AMI and IVVO, as Mr. Reimer describes in his Direct Testimony.

As a result, the cost-benefit model for this CPCN application includes the portions of the FAN that are designated as necessary to support AMI meters and IVVO – specifically, the Wireless Smart Utility Network ("WiSUN") that connects meters, sensors, distribution devices, and signal repeaters to create a reliable wireless mesh network. The meters and repeaters that constitute the AMI, along with the capacitors and voltage monitors that constitute the IVVO devices, will have embedded communication modules that will allow them to communicate directly with the FAN's access points on the WiSUN core mesh infrastructure. The AMI meters will also have the ability to communicate with each other on the

WiSUN network. As such, WiSUN costs are associated with AMI and IVVO and are included in the CPCN cost-benefit modeling.

As Mr. Weimer further discusses, implementation of the WiSUN component of the FAN communication network is necessary for the field technology components to operate. He notes that, as an example, AMI meters cannot be read automatically if they are installed before the FAN is deployed and operating. Consequently, the AMI, IVVO, and consolidated models assume implementation of the FAN from 2016 through 2021, consistent with the timeline to implement the AMI meters and IVVO assets slightly later.

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 as a result of advanced metering. As with the FAN, IT work is not a standalone program that provides benefits in its own right; rather, it is a necessary component of the AMI and IVVO programs. Therefore, the costs of IT efforts for AMI and IVVO are included in the cost-benefit model for these components of the CPCN Projects.

Q. HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR 2016 THROUGH 2021?

A. Each subject matter expert provided estimated capital and O&M costs and benefits, as well as customer benefit estimates in 2016 dollars by year for the period 2016 through 2021. Almost all of these costs and benefits were converted into nominal dollars within the model using assumptions for labor and non-labor inflation over the analysis period. I say "almost all" because the costs of AMI meters during the initial deployment period were not escalated, as it is expected that during the period of deployment the Company will have a fixed price contract with the chosen AMI vendor for AMI meters. Therefore, escalating these costs to reflect inflationary pressures is not necessary. After the initial deployment of AMI meters, any additional meter costs for new connections or AMI meter failures were escalated.

Q. **HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR 2022 THROUGH 2035?**

A. In addition to the costs and benefits for the period of 2016 through 2021, each subject matter expert estimated the trailing capital and O&M costs for each respective part of the project for the remaining years of the analysis period (i.e. 2022-2035). These trailing O&M and capital costs were provided in 2016 dollars by each technical witness and were escalated to nominal dollars for the full twenty-year analysis period (2016-2035). Estimating the trailing capital and O&M costs are necessary to examine the complete lifecycle costs and benefits of each of the CPCN Projects programs beyond the initial implementation period.

Benefits were also estimated for the period of 2022 through 2035 using the avoided fuel and capacity costs consistent with the Company's DSM assumptions, or by continuing to escalate the 2021 benefits to the appropriate future year.

Q. DO THE COST INPUTS FOR AMI AND IVVO INCLUDE CONTINGENCY ASSUMPTIONS?

A. Yes. In addition to the cost estimates, the technical witnesses developed contingency estimates for each aspect of the project that warranted a contingency. These contingency estimates are depicted on Attachment SJH-2, Attachment SJH-3, and Attachment SJH-4 as cost line items that include the identifier "CON." The testimonies of the technical witnesses for the Company provide additional support for the contingency amounts included in the cost-benefit analysis.

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. Doing so presents the project at the high end of the cost estimates, and thus in a conservative manner.

Q. ONCE THE COSTS AND BENEFITS FROM EACH SUBJECT MATTER EXPERT WERE INPUT INTO 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 additional 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 customer impact of the capital spend, which is how the Company would calculate electric rate recovery on the underlying investment.

Second, for O&M costs, the model assumes that those costs would be expensed in the year they were incurred, and would be directly passed on to customers through Public Service's electric rates.

Q. HOW DOES THE MODEL CONVERT THE ESTIMATES OF NET CAPITAL REVENUE REQUIREMENT, O&M COSTS AND BENEFITS, AND CUSTOMER BENEFITS TO A BENEFIT-TO-COST RATIO?

A. Once the twenty year stream of the net capital revenue requirements, O&M costs and benefits, and customer benefits are calculated, the streams can be compared on a net present value basis. Each stream of costs or benefits is present valued back to 2016 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 can be calculated. A benefit-to-cost ratio of 1.0 indicates benefits 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. Summaries of these calculations are included as Attachments SJH-1.

Q. WHAT STEPS DID PUBLIC SERVICE TAKE TO VERIFY THAT THE MODEL IS STRUCTURALLY SOUND?

A. The modeling structure that was chosen was based on external benchmarking to similar exercises undertaken by 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 and Demand Side Management, as well as 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 of the CPCN Projects Application.

B. <u>Quantitative Inputs</u>

1. <u>AMI Inputs</u>

Q. WHAT ARE THE KEY COSTS AND BENEFITS OF AMI?

A. Company witness Mr. Borchardt discusses the costs and benefits of AMI in detail in his testimony. Overall, AMI meters will (i) provide customer energy usage information that supports greater customer energy usage choice; (ii) assist with service outages and restoration; (iii) provide voltage measurement information to assist in load flow and voltage calculations performed in the ADMS; and (iv) serve as signal repeaters for other AMI meters and FAN network components. The purchase of AMI meters also enables the Company to retire less advanced technology and avoid the purchase of additional, less functional advanced meter reading ("AMR") meters in the future.

The key costs of AMI include the meters themselves as well as the labor cost of installation, supporting FAN and IT resources, AMI program and change management, and other supporting labor.

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 Mr. Borchardt, Mr. Reimer, Mr. Lee, and Mr. Harkness:

Table SJH-1-Capital Costs

Capital Cost	Description	Additional Detail
Meters and Installation	The capital costs portion of AMI meter purchase and installation, per the Company's capitalization policy.	Direct Testimony of Mr. Borchardt.
Field Area Network (AMI)	The capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Reimer.
IT Systems and Integration	The capital costs associated with the various IT infrastructure and integration in support of AMI.	Direct Testimony of Mr. Harkness.
Program Management	The capital costs associated with internal management of AMI.	Direct Testimony of Mr. Lee
Change Management:	The capital costs associated with Operational Change Management of AMI.	Direct Testimony of Mr. Lee.
AMI Operations (Personnel):	The capital costs of both internal and external support personnel.	Direct Testimony of Mr. Borchardt.

Table SJH-2-Capital Benefits

Capital Benefit	Description	Additional Detail
Distribution System Management	More efficient use of capital dollars to maintain the distribution system.	Direct Testimony of Mr. Borchardt.
Outage Management Efficiency	Improved capital spend efficiency during outage events.	Direct Testimony of Mr. Borchardt.
Avoided AMR Meter Purchases	By purchasing new advanced AMI meters, the Company avoids the need to replace failing AMR meters.	Direct Testimony of Mr. Borchardt.

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 technical witnesses. The costs and benefits associated with improvements to the Saver's Switch program are discussed later in my testimony.

Table SJH-3-O&M Costs

O&M Cost	Description	Additional Detail
Meters and Installation	The O&M costs portion of AMI meter purchase and installation, per the Company's capitalization policy.	Direct Testimony of Mr. Borchardt.
Field Area Network (AMI)	The O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Reimer.
IT Systems and Integration	The O&M costs associated with the various IT infrastructure and integration in support of AMI.	Direct Testimony of Mr. Harkness.
AMI Operations (Personnel)	The O&M costs of both internal and external support personnel.	Direct Testimony of Mr. Borchardt.
Program Management	The O&M costs associated with internal management of AMI.	Direct Testimony of Mr. Lee.
Change Management	The O&M costs associated with Operational Change Management of AMI.	Direct Testimony of Mr. Lee.
Saver's Switch Program Costs	The cost of upgrading the Saver's Switch program to utilize two-way communicating switches.	Additional detail contained later in my Testimony.

Table SJH-4-AMI O&M Benefits

O&M Benefit	Description	Additional Detail
Reduction in Meter Reading Costs	Less labor required to read meters.	Direct Testimony of Mr. Borchardt.
Reduction in Field & Meter Services	Less labor required to address meter and outage complaints.	Direct Testimony of Mr. Borchardt.
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.	Direct Testimony of Mr. Borchardt.
Improvement in Customer Care	Call center intake reduced after initial adoption period.	Direct Testimony of Mr. Borchardt.
Distribution System Management	Increased efficiency of distribution maintenance costs.	Direct Testimony of Mr. Borchardt.
Outage Management Efficiency	Improved O&M spend efficiency during outage events.	Direct Testimony of Mr. Borchardt.
Reduced Consumption Inactive Premise	Expedited ability to turn off power quickly when determined premise has been vacated.	Direct Testimony of Mr. Borchardt.
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible accounts.	Direct Testimony of Mr. Borchardt.
Customer Outage Reduction	Reduction in customer outage minutes due to faster response capability	Direct Testimony of Mr. Borchardt.
Demand Response: Avoided Capacity	Improved capability and performance of the Saver's Switch program.	Additional detail contained later in my Testimony.
Elasticity: Avoided Capacity	Customer demand savings in response to new rate structures.	Brattle Group Report, Attachment SJH-5.

Q. CAN YOU PROVIDE AN OVERVIEW OF THE SAVER'S SWITCH PROGRAM AND DESCRIBE HOW THE UTILIZATION OF AMI AND THE FAN CAN IMPROVE THE PROGRAM?

A. Yes. The Company's Saver's Switch program is a voluntary direct load control program wherein the Company installs a switch on a participant's air conditioning unit, and is permitted to shut off the participant's air conditioning for short periods of time during high load hours. The implementation of the AMI meters and associated infrastructure provide an opportunity for the Company to improve the performance of its Saver's Switch program in two ways:

First, by retrofitting the existing one-way communication switches with two-way communication switches, the Company will be able monitor which switches are performing correctly and replace failing or troublesome devices. These two-way switches will utilize the FAN for communication, and would be directly enabled through the actions of this CPCN.

Secondly, the current one-way paging system does not always reach all switches. A more robust FAN network will be able to better reach a higher percentage of the switches during load control hours, and provide better response to direct load control events.

Q. WHAT COSTS AND BENEFITS DOES THE COMPANY ESTIMATE WOULD BE INCURRED IF THE CURRENT SAVER'S SWITCH TECHNOLOGY WERE RETROFITTED?

A. The Company estimates that it would cost an incremental $9.27 million to retrofit the current population of approximately 185,000 Saver's Switch participants to the two-way communication enabled devices rather than the current Saver's Switch technology. As a result of this upgrade, the Company estimates that the successful execution of direct load control events would increase from an historical rate of 86% to 94%. This is estimated to result in an additional 13.8 MW of direct load control available through the Saver's Switch program without otherwise growing participation. These costs and benefits are captured within Attachment SJH-2 on the "Saver's Switch" line of O&M costs and the "Demand Response" line of Energy and Capacity benefits.

Q. IS THE COMPANY SEEKING PERMISSION TO IMPLEMENT THESE CHANGES TO THE SAVER'S SWITCH PROGRAM AS PART OF THIS CPCN?

A. No, it is not. The estimated costs and benefits of this enhanced two-way communication functionality were included in the cost-benefit analysis as this is a new capability that is enabled by the technologies sought through this CPCN, and can be used in the future to benefit our customers. We believe including both the costs and the benefits provides a more complete overall view. However, the Company is not seeking Commission approval of the costs or benefits of these changes to the Saver's Switch program. To the extent the Commission approves the Company's proposal to implement the technologies proposed in this CPCN, the Company would bring forth a more robust discussion of these changes to the Saver's Switch program in the appropriate proceeding.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING PUBLIC SERVICE'S ELASTICITY ASSUMPTIONS?

A. Yes. Public Service engaged The Brattle Group to model likely residential customer response to demand rates the Company proposes to make available as enabled by AMI implementation. The Brattle Group's analysis is attached to my Direct Testimony as Attachment SJH-5. As noted on pages four and five of Attachment SJH-5, The Brattle Group analysis shows that annual customer class peak demand would likely be reduced by an average of 11.6% across all customers over the measuring period, using a system-based approach to measuring customer response. The Brattle Group further concluded at page 5 of Attachment SJH-5 that its recommended approach is "an internally consistent modeling framework that has been adopted by regulatory commissions in other jurisdictions in the context of assessing the benefits and costs of grid modernization."

Public Service therefore relied upon The Brattle Group's elasticity analysis to assume that a consistent reduction in peak demand would be achievable as a function of the demand rates AMI will enable as part of the Company's CPCN Projects proposal. This reduction is then incorporated into the cost-benefit analysis 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 witnesses Ms. Jackson and Mr. Borchardt, Public Service proposes an opt-out approach to AMI metering, meaning that customers will be automatically integrated into the new system unless they actively opt out. The Brattle Group elasticity analysis assumed this opt-out approach, and de-rated the estimated peak reductions of customers who opt out by 40% in its model. However, 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. Further, Company witness Mr. Borchardt investigated the likely opt-out rates based upon other utilities' experiences. Mr. Borchardt discusses the review in his Direct Testimony.

Q. WHAT IS THE IMPACT OF THESE OPT-OUT ASSUMPTIONS ON THE COST-BENEFIT ANALYSIS?

A. There is no net cost impact because Public Service proposes 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. As Mr. Borchardt explains in more detail, these charges would be established in an amount that directly offsets the costs of opting out, such that there is no material net impact to the cost-benefit analysis.

2. <u>IVVO Inputs</u>

Q. WHAT ARE THE PRIMARY BENEFITS AND COSTS OF IVVO?

A. Company witness Mr. Nickell discusses the primary purpose, costs and benefits of the IVVO program from his perspective as Manager, System Planning and Strategy South. 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. Currently, the Company is not able to consistently monitor voltage levels throughout its feeders, and therefore must operate the system at a higher voltage than may be required with better monitoring capability.

The primary costs of implementing IVVO relate to installation of application assets and communications, communications operations, asset operations, and personnel support. The benefits of IVVO that were quantified in the cost-benefit analysis are the impacts of avoided capacity and energy costs associated with the program. As described in more detail in the Direct Testimony of Mr. Nickel, through the implementation of IVVO the Company will be able to control the voltage on a distribution feeder to a much 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 result in a customer's devices operating more efficiently, and will effectuate energy and demand savings for the system.

Q. ARE THERE ANY POTENTIALLY QUANTIFIABLE CUSTOMER BENEFITS OF IVVO THAT THE COMPANY DID NOT ATTEMPT TO ESTIMATE?

A. Yes. The Company only quantified the benefits of IVVO that would be socialized to the entire system; these are avoided capacity, avoided energy and deferred transmission and distribution capital investment.

In addition to these broad benefits, the customers whose feeders are equipped with IVVO assets will experience higher efficiencies from their personal electrical devices. This improved efficiency will result in lower bills for those customers. However, since the Company is not proposing to implement IVVO for the entirety of its service territory through this CPCN, and these efficiency benefits would not apply to all customers, the Company chose not to quantify them as part of this CPCN. In this way, Public Service remained consistent with its efforts to provide a conservative view of costs and benefits of IVVO (and AMI).

Q. HOW WERE IVVO CAPITAL INPUTS DERIVED FOR PURPOSES OF THE COST-BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the IVVO program are detailed in the Direct Testimony of Company witnesses Mr. Nickell, Mr. Lee, Mr. Reimer, and Mr. Harkness.

Q. WHAT ARE THE CAPITAL COSTS AND BENEFITS OF IVVO?

A. A summary of capital costs is set forth in Table SJH-5, below. IVVO's quantifiable benefits are largely O&M benefits; therefore, I do not include a capital benefits table.

Table SJH-5-Capital Costs of IVVO

Capital Cost	Description	Additional Detail
Assets and Installation	The capital costs of the IVVO devices and installation.	Direct Testimony of Mr. Nickell.
Field Area Network (IVVO)	The capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Reimer.
IT Systems and Integration	The capital costs associated with the various IT infrastructure and integration in support of IVVO.	Direct Testimony of Mr. Harkness.
Program Management	The capital costs associated with internal management of IVVO.	Direct Testimony of Mr. Lee.
Change Management	The capital costs associated with Operational Change Management of IVVO.	Direct Testimony of Mr. Lee.
IVVO Integration (Personnel)	The capital costs of both internal and external support personnel.	Direct Testimony of Mr. Nickell.

Q. HOW WERE IVVO O&M INPUTS DERIVED FOR PURPOSES OF THE COST-BENEFIT MODEL?

A. IVVO O&M costs and benefits were developed by Public Service's technical witnesses as set forth below:

Table SJH-6-IVVO O&M Costs

O&M Cost	Description	Additional Detail
Assets and Installation	The O&M costs of the IVVO devices and installation.	Direct Testimony of Mr. Nickell.
Field Area Network (IVVO)	The O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Reimer.
IT Systems and Integration	The O&M costs associated with the various IT infrastructure and integration in support of IVVO.	Direct Testimony of Mr. Harkness.
Program Management	The O&M costs associated with internal management of IVVO.	Direct Testimony of Mr. Lee.
Change Management	The O&M costs associated with Operational Change Management of IVVO.	Direct Testimony of Mr. Lee.

Table SJH-7-O&M Benefits

O&M Benefit	Description	Additional Detail
Fuel Savings (Avoided Energy)	Fuel cost savings associated with avoided energy and line losses.	Direct Testimony of Mr. Nickell
Avoided Capacity Costs	Avoided generation, transmission, and distribution capacity costs achieved through demand reduction.	Direct Testimony of Mr. Nickell

Q. HOW WOULD YOU CHARACTERIZE THE COST AND BENEFIT BUDGETING ASSUMPTIONS FOR AMI AND IVVO?

A. I would characterize this model as a conservative representation of estimated costs and benefits. Because AMI and IVVO planning are still in their early phases, consistent with a project for which the Commission has not yet determined whether the project is needed, the contingencies represent early estimates of potential additional costs. Likewise, Public Service has estimated customer adoption and response on the basis of historically available information; as technologies continue to improve, the benefits associated with these technologies may also increase. Public Service's goal is to represent a conservative but realistic analysis to support the Commission's review of the Company's CPCN Project's Application.

C. <u>Qualitative Analysis</u>

Q. WILL THE AMI PROGRAM PROVIDE BENEFITS 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 in whole or in part. For example, it is difficult to quantify Public Service customers' broad expectation to have more choice in and control over their energy usage. 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.

These unquantifiable benefits are largely discussed by Company witnesses Mr. Borchardt and 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 public service employees; and
- Improvements in power quality.

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, 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 access of low income customers to energy efficiency savings;
- Environmental benefits of enhanced energy efficiency; and
- Increased hosting capacity of distributed energy resources.

Q. CAN PUBLIC SERVICE PROVIDE MORE DETAIL REGARDING THESE QUALITATIVE BENEFITS OF IVVO?

A. Yes. Company witness Mr. Nickell addresses the above benefits in his Direct Testimony. With respect to low income customers' access to energy efficiency savings, I note that Mr. Nickell explains how IVVO can reduce voltage, and therefore save customers money, without requiring any change in energy usage or activities on the customers' part. Therefore, IVVO has the added benefit of saving money for low income customers without implementing new low income-specific programs.

Q. WHY DIDN'T THE COMPANY ATTEMPT TO QUANTIFY THESE BENEFITS?

A. Although the Company feels strongly that these benefits are achievable and 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 Public Service's business model and role as a public utility, but do not directly lend themselves to monetization. Similarly, while safety and environmental benefits are quantified in some circumstances, doing so often requires placing values on human health – which Public Service opted not to attempt.

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 CPCN Projects components, and which we were able to value with the highest degree of 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 cost-benefit analysis as a baseline of our business case for our CPCN Projects, and then evaluate and discuss the merits of the additional beneficial impacts to our customers.

III. COST-BENEFIT ANALYSIS RESULTS

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE AMI PROGRAM.

A. Table SJH-8 summarizes the results of the Company's evaluation of AMI.

Table SJH-8

AMI	
Benefits ($M)	**(401)**
O&M Savings & Customer Benefits	(159)
Avoided Energy and Capacity	(241)
Costs ($M)	**452**
O&M Cost	115
Change in Cap Revenue Requirement	337
Benefit/Cost Ratio	**0.89**

Attachment SJH-2 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 0.89, which indicates that the costs exceed quantitative benefits over the analysis period. As described above, this analysis assumes a conservative approach to cost estimates, given that Public Service is in the early stages of seeking a determination of need for the project before entering detailed design, contracting, and engineering phases.

Q. PLEASE SUMMARIZE THE QUANTITATIVE COST AND BENEFIT COMPARISON FOR THE IVVO PROGRAM.

A. Table SJH-9 summarizes the results of the Company's evaluation of IVVO:

Table SJH-9

IVVO	
Benefits ($M)	**(144)**
O&M Savings & Customer Benefits	0
Avoided Energy and Capacity	(144)
Costs ($M)	**189**
O&M Cost	47
Change in Cap Revenue Requirement	142
Benefit/Cost Ratio	**0.76**

Attachment SJH-3 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 approximately 0.76. As described above, this analysis assumes a conservative approach to cost estimates and benefits, given that Public Service is in the early stages of seeking a determination of need for the project before entering detailed design, contracting, and engineering phases.

Q. IS THERE ANOTHER FRAMEWORK THAT COULD ENHANCE THE BENEFIT-TO-COST RATIO OF THE IVVO PROGRAM?

A. Yes. By Commission Decision C14-0731 in Docket No. 13A-0686EG, the Commission determined that programs like Distribution Voltage Optimization ("DVO") are in fact DSM programs, and can be evaluated consistent with other DSM measures using a Modified Total Resource Cost Test ("mTRC"). Company witness Mr. Lee explains that both DVO and IVVO provide DSM benefits through voltage optimization.

Q. WHAT IS THE MODIFIED TOTAL RESOURCE COST TEST?

A. The mTRC is one of the cost tests that the Commission and Company use to evaluate DSM measures and help determine if a proposed portfolio of DSM measures is likely to be cost effective. In similar fashion to the cost-benefit analysis presented here, the mTRC compares the costs and benefits of a given DSM measure or DSM portfolio, but includes an additional 10% adder to the benefits. The 10% adder, also known as the Non-Energy Benefits Adder, is designed to help provide a quantification of other positive attributes of DSM such as health and well-being, customer satisfaction, and economic benefits of lower energy bills.

Q. HAVE YOU CALCULATED THE mTRC SCORE OF IVVO?

A. Yes. Using a 10% non-energy benefit adder consistent with the Company's prior DSM plan filings, IVVO has an mTRC score of 0.84.

Q. HAVE YOU BENCHMARKED THE COSTS OF THE COMPANY'S IVVO PROGRAM AGAINST THE DVO PROGRAM THAT THE COMPANY PROPOSED IN PROCEEDING 13A-0686EG?

A. Yes I have. In proceeding 13A-0686EG, Company witness Ms. Kelly A. Bloch testified that DVO was projected to cost approximately $92 million dollars over the five-year implementation period, with the costs including distribution equipment, distribution upgrades, software, and communications. IVVO is projected to cost approximately $151 million from 2016 to 2022 inclusive of the assets and upgrades necessary to enable IVVO, as well as its allocation of FAN costs, IT, and operational change management. Although IVVO is more expensive over the implementation period than DVO was projected to be, IVVO is more integrated with the distribution grid and is a more dynamic system as compared to DVO and is capable of achieving greater energy savings. The differences between IVVO and DVO are discussed in more detail in the Direct Testimony of Mr. Lee.

Q. HAVE YOU ALSO BENCHMARKED THE BENEFITS OF THE COMPANY'S IVVO PROGRAM AGAINST THE DVO PROGRAM?

A. Yes I have. In proceeding 13A-0686EG, Company witness Ms. Debra L. Sundin testified that DVO was projected to achieve energy savings of approximately 506 GWh and reduce system peak demand by approximately 11 MW over the five year term of the DVO project. Similarly, IVVO is projected to achieve energy savings of approximately 1,160 GWh and reduce system peak demand by approximately 44 MW over the first five years of operation (2019 through 2023).

If compared on a dollar per GWh saved basis over the first five years of operation, DVO was projected to cost approximately $182,000/GWh versus IVVO at approximately $130,000/GWh. We provide this information to briefly show how IVVO compares to DVO in terms of both costs and energy savings.

Q. DO YOU ALSO PROVIDE A COMBINED SUMMARY OF THE COSTS AND QUANTITATIVE BENEFITS OF THE PROGRAMS THAT ARE THE SUBJECT OF THIS CPCN APPLICATION?

A. Yes. Table SJH-10 summarizes the results of the Company's evaluation of the combined AMI/IVVO program:

Table SJH-10

CPCN (AMI and IVVO)	
Benefits ($M)	**(544)**
O&M Savings & Customer Benefits	(159)
Avoided Energy and Capacity	(385)
Costs ($M)	**640**
O&M Cost	161
Change in Cap Revenue Requirement	479
Benefit/Cost Ratio	**0.85**

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL VALUE OF THE PROGRAMS INCLUDED IN THIS CPCN APPLICATION?

A. On a combined basis, the quantitative benefits of AMI and IVVO are expected to be lower than program costs, with an expected benefit-to-cost ratio of approximately 0.85. This total represents a simple combination of AMI and IVVO respective costs and benefits, inclusive of the costs attributable to that portion of the FAN needed to enable AMI and IVVO, presented on a 2016 NPV basis. As discussed earlier in my testimony, if IVVO is evaluated using its mTRC score of

0.84, the combined benefit to cost ratio of both AMI and IVVO would improve to 0.87.

Q. WHY SHOULD THE COMMISSION CONSIDER GRANTING A CPCN FOR AMI AND IVVO IF COMBINED PROGRAM COSTS EXCEED THE OVERALL QUANTITATIVE BENEFITS?

A. There are several reasons why AMI and IVVO are overall valuable resources, even if costs slightly exceed estimated quantifiable benefits.

First, the Company cannot achieve greater transparency into its distribution system, greater opportunities for demand side management, and improved reliability without the AMI and IVVO implementation. As Ms. Jackson discusses, these are also necessary components of any new rate structures or other initiatives the Commission may wish to implement; right now, Public Service simply does not have the technical capability or insight into customer usage to implement such technologies or customer support without AMI and IVVO.

Second, as discussed by Company witnesses Mr. Lee and Ms. Jackson, AMI, IVVO, and their related FAN components are part of a larger grid advancement effort that includes Public Service's ordinary-course investments in the Advanced Distribution Management System ("ADMS") and the Fault Location Isolation and Service Restoration ("FLISR") application. As discussed by Mr. Nickell, ADMS acts as a centralized support system that assists with monitoring and control of the electric distribution system, and will work in tandem with AMI and IVVO to establish a comprehensive grid communication tool. As Mr. Nickell further notes in his Direct Testimony, data from AMI meters will inform FLISR calculations regarding the location of line faults and the most appropriate switching plan. IVVO voltage regulation works in tandem with FLISR, identifying optimal voltage levels both before and after a FLISR event. ADMS ties the various pieces of the system together, with all components utilizing and relying upon the FAN. Accordingly, approval of the AMI and IVVO programs should be viewed in the larger context and with the broader goal of advancing Public Service's distribution grid as a whole.

Third, 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. Public Service recognizes 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.

Fourth, it is important to advance Public Service's grid to continue providing safe, increasingly reliable electric service to our customers not just in the present but also into the future. Consequently, the AGIS program will support a fundamental utility function while solving for existing infrastructure that is no longer maximizing service to our customers.

Overall, our AGIS program is necessary to bring our distribution grid into the future, offer greater customer choice, and take advantage of opportunities to use up-to-date technology to support demand side management, peak demand reductions, and a more resilient, responsive grid.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Samuel J. Hancock

I graduated from the University of Colorado, Boulder, with a Bachelor of Science Degree in Mechanical Engineering.

I began my employment with Xcel Energy Services, Inc. in September 2012, as a Resource Planning Analyst II. In December 2015, I was promoted to Manager, Regulatory Project Management which is my current role. My responsibilities have included supporting various regulatory matters including competitive resource acquisition processes, new product design, economic analyses of existing and potential resource options, as well as other technical analyses for Xcel Energy's operating companies.

Prior to my employment with Xcel Energy Services, Inc., I was employed by the consulting firm Energy & Resource Consulting Group, LLC ("ERG") as a Senior Engineer. My responsibilities at ERG included various engineering and financial analysis related to the electric and natural gas utility industry. This includes supply planning, engineering analysis, demand side management, regulatory compliance review, engineering simulation and modeling, as well as financial auditing. I have also provided technical support in several regulatory dockets which have involved independent system operators, formula rate plans, rate design, utility system planning, fuel forecasting, storm cost auditing, utility system agreements, demand side management and energy efficiency program design.

I have testified before the Colorado Public Utilities Commission in Proceeding Nos. 13A-0836E, 14A-0302E, 15A-0304E, and 16A-0319E. I have also presented testimony before the City Council of New Orleans in Proceeding No. UD-11-03 regarding an application to enter into a power purchase agreement for the capacity and energy associated with a 550 MW combined cycle gas turbine facility.

Attachment SJH-1
Samuel J. Hancock
Hearing Exhibit 108
Summary of AMI/IVVO Cost-Benefit Analysis
2016 NPV ($Millions)
Page 1 of 1

CPCN (AMI and IVVO)	
Benefits ($M)	**(544)**
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AMI	
Benefits ($M)	**(401)**
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Avoided Energy and Capacity	(241)
Costs ($M)	**452**
O&M Cost	115
Change in Cap Revenue Requirement	337
Benefit/Cost Ratio	**0.89**

IVVO	
Benefits ($M)	**(144)**
O&M Savings & Customer Benefits	0
Avoided Energy and Capacity	(144)
Costs ($M)	**189**
O&M Cost	47
Change in Cap Revenue Requirement	142
Benefit/Cost Ratio	**0.76**

Northern States Power Company

Attachment SJH-2
Samuel J. Hancock
Hearing Exhibit 108
AMI Cost & Benefit Summary
Includes Escalation and Applicable Loaders
Cost/(Benefit)
Page 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
1		NPV	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2	Meters Replaced		0	0	173,615	796,163	447,891	97,894	23,643	24,012	24,386	24,767	25,153	25,545	25,944	26,349	26,760	27,177	27,601	28,032	28,469	28,913
3	Cumulative Meters Replaced		0	0	173,615	969,778	1,417,669	1,515,563	1,539,206	1,563,217	1,587,603	1,612,370	1,637,523	1,663,068	1,689,012	1,715,361	1,742,120	1,769,297	1,796,898	1,824,930	1,853,399	1,882,312
4	**Capital Items**																					
5	***Costs***																					
6	Meters and Installation	176,545,760	0	210,000	24,126,434	103,305,910	59,219,451	14,645,303	3,354,060	3,474,511	3,599,288	3,728,546	3,862,445	4,001,153	4,144,843	4,293,692	4,447,887	4,607,620	4,773,089	4,944,500	5,122,067	5,306,010
7	Meters and Installation - CON	15,085,370	0	21,000	2,144,622	8,719,829	5,062,354	1,359,828	277,979	287,961	298,303	309,015	320,113	331,609	343,517	355,854	368,633	381,872	395,585	409,792	424,508	439,753
8	Field Area Network (AMI)	14,221,142	185,259	4,354,641	6,211,515	6,378,695	174,059	140,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Field Area Network (AMI) - CON	5,688,457	74,104	1,741,856	2,484,606	2,551,478	69,624	56,152	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	IT Systems and Integration	54,265,768	1,933,118	31,971,946	25,625,921	0	635,475	0	487,258	1,103,937	0	0	715,648	537,972	474,275	759,452	0	0	1,399,901	523,638	0	855,266
11	IT Systems and Integration - CON	47,498,465	1,650,826	28,358,894	21,940,609	0	542,677	0	477,603	1,005,459	0	0	611,143	527,313	474,275	648,550	0	0	1,270,442	523,638	0	730,372
12	AMI Program Management	6,555,723	100,270	1,544,359	1,919,505	2,255,835	2,181,563	332,119	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	AMI Change Management	4,790,194	61,833	955,747	1,741,885	1,928,148	1,173,848	199,554	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	AMI Program & Change Management - CON	1,134,592	16,210	250,011	366,139	418,398	335,541	53,167	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	AMI Operations (Personnel)	6,081,126	283,705	607,644	2,038,980	2,190,894	2,100,195	607,220	0	0	0	0	0	0	0	0	0	0	0	0	0	0
16	***Benefits***																					
17	*Capital Benefits*																					
18	Distribution System Management	(12,223,341)	0	0	0	0	(1,257,342)	(1,371,048)	(1,420,285)	(1,471,290)	(1,524,127)	(1,578,861)	(1,635,561)	(1,694,298)	(1,755,143)	(1,818,174)	(1,883,468)	(1,951,107)	(2,021,176)	(2,093,760)	(2,168,951)	(2,246,842)
19	Outage Management Efficiency	(1,006,129)	0	0	0	(73,810)	(108,366)	(116,351)	(118,678)	(121,052)	(123,473)	(125,942)	(128,461)	(131,031)	(133,651)	(136,324)	(139,051)	(141,832)	(144,668)	(147,562)	(150,513)	(153,523)
20	Avoided AMR Meter Purchases	(35,695,326)	0	0	0	(1,881,423)	(3,527,571)	(3,985,441)	(3,875,169)	(4,031,146)	(4,192,988)	(4,360,908)	(4,535,129)	(4,715,881)	(4,903,403)	(5,097,943)	(5,299,757)	(5,509,111)	(5,726,280)	(5,951,550)	(6,185,216)	(6,427,584)
21	**Total Capital Costs**		4,305,324	70,016,097	88,600,215	127,749,187	71,494,787	17,393,725	4,596,900	5,871,869	3,897,591	4,037,561	5,509,349	5,398,046	5,436,911	6,057,547	4,816,520	4,989,491	7,839,017	6,401,568	5,546,575	7,331,401
22	**Total Capital Benefits**		0	0	0	(1,955,233)	(4,893,279)	(5,472,840)	(5,414,132)	(5,623,488)	(5,840,588)	(6,065,712)	(6,299,151)	(6,541,209)	(6,792,197)	(7,052,441)	(7,322,276)	(7,602,050)	(7,892,124)	(8,192,872)	(8,504,680)	(8,827,950)
23	**Net Capital Revenue Requirement Impact**	337,027,874	0	0	7,686,810	54,428,536	65,751,759	66,777,674	63,718,720	54,530,861	34,296,041	32,332,151	30,900,694	29,228,944	27,296,745	25,951,829	24,286,532	22,240,041	20,854,968	18,935,970	15,545,582	14,233,687
24	**O&M Items**																					
25	***Costs***																					
26	Meters and Installation	1,894,682	376,073	369,600	198,615	821,163	472,891	122,894	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	Meters and Installation - CON	154,249	0	36,960	19,861	82,116	47,289	12,289	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	Field Area Network (AMI)	20,471,233	85,261	384,660	977,799	1,783,417	2,225,546	2,251,707	2,209,035	2,253,215	2,298,280	2,344,245	2,391,130	2,438,953	2,487,732	2,537,486	2,588,236	2,640,001	2,692,801	2,746,657	2,801,590	2,857,622
29	Field Area Network (AMI) - CON	8,188,493	34,104	153,864	391,120	713,367	890,218	900,683	883,614	901,286	919,312	937,698	956,452	975,581	995,093	1,014,995	1,035,294	1,056,000	1,077,120	1,098,663	1,120,636	1,143,049
30	IT Systems and Integration	35,454,594	53,983	2,586,141	3,874,930	3,222,522	3,286,972	3,352,712	3,419,766	3,488,161	3,557,925	3,629,083	3,701,665	3,775,698	3,851,212	3,928,236	4,006,801	4,086,937	4,168,676	4,252,049	4,337,090	4,423,832
31	IT Systems and Integration - CON	33,791,980	46,100	2,355,061	3,639,229	3,087,075	3,148,817	3,211,793	3,276,029	3,341,550	3,408,381	3,476,548	3,546,079	3,617,001	3,689,341	3,763,128	3,838,390	3,915,158	3,993,461	4,073,330	4,154,797	4,237,893
32	AMI Operations (Personnel)	3,774,614	0	137,354	753,611	976,374	459,708	107,066	281,541	287,171	292,915	298,773	304,749	310,844	317,060	323,402	329,870	336,467	343,196	350,060	357,062	364,203
33	AMI O&M - CON	377,461	0	13,735	75,361	97,637	45,971	10,707	28,154	28,717	29,291	29,877	30,475	31,084	31,706	32,340	32,987	33,647	34,320	35,006	35,706	36,420
34	AMI Program Management	722,148	10,000	173,400	208,080	254,690	238,135	33,122	0	0	0	0	0	0	0	0	0	0	0	0	0	0
35	AMI Change Management	3,185,372	42,622	637,620	1,157,861	1,281,530	779,170	130,716	0	0	0	0	0	0	0	0	0	0	0	0	0	0
36	AMI Program & Change Management - CON	385,824	0	81,102	136,594	153,622	101,731	16,384	0	0	0	0	0	0	0	0	0	0	0	0	0	0
37	Saver's Switch Program Costs	6,210,954	0	0	0	983,719	1,003,393	1,023,461	1,043,930	1,064,809	1,086,105	1,107,827	1,129,983	1,152,583	1,175,635	0	0	0	0	0	0	0
38	***Benefits***																					
39	*O&M Benefits*																					
40	Reduction in Meter Reading Costs	(34,074,586)	0	0	0	(2,499,723)	(3,670,048)	(3,940,472)	(4,019,282)	(4,099,667)	(4,181,661)	(4,265,294)	(4,350,600)	(4,437,612)	(4,526,364)	(4,616,891)	(4,709,229)	(4,803,414)	(4,899,482)	(4,997,471)	(5,097,421)	(5,199,369)
41	Reduction in Field and Meter Services Costs	(32,354,359)	0	0	0	(2,373,526)	(3,484,768)	(3,741,541)	(3,816,372)	(3,892,699)	(3,970,553)	(4,049,964)	(4,130,963)	(4,213,583)	(4,297,854)	(4,383,811)	(4,471,488)	(4,560,917)	(4,652,136)	(4,745,178)	(4,840,082)	(4,936,884)
42	Improvement in Customer Care	(2,574,836)	0	0	0	(188,891)	(277,326)	(297,761)	(303,716)	(309,790)	(315,986)	(322,306)	(328,752)	(335,327)	(342,033)	(348,874)	(355,852)	(362,969)	(370,228)	(377,633)	(385,185)	(392,889)
43	Distribution System Management	(37,674)	0	0	0	0	(3,875)	(4,226)	(4,377)	(4,535)	(4,698)	(4,866)	(5,041)	(5,222)	(5,410)	(5,604)	(5,805)	(6,014)	(6,230)	(6,453)	(6,685)	(6,925)
44	Outage Management Efficiency	(1,068,273)	0	0	0	(78,369)	(115,060)	(123,538)	(126,009)	(128,529)	(131,099)	(133,721)	(136,396)	(139,124)	(141,906)	(144,744)	(147,639)	(150,592)	(153,604)	(156,676)	(159,809)	(163,006)
45	*Energy & Capacity Benefits*																					
46	Demand Response - Avoided Capacity/Trans	(9,811,268)	0	0	0	(157,836)	(321,990)	(492,669)	(669,972)	(854,286)	(1,045,644)	(1,244,253)	(1,450,378)	(1,664,387)	(1,886,197)	(1,924,062)	(1,962,531)	(2,001,816)	(2,041,813)	(2,082,629)	(2,124,266)	(2,166,725)
47	Brattle Elasticity - Avoided Capacity/Trans	(231,530,101)	0	0	0	(9,816,305)	(20,667,360)	(25,790,189)	(27,145,676)	(27,892,964)	(28,468,531)	(29,467,146)	(30,389,427)	(31,292,765)	(32,093,961)	(33,322,464)	(34,513,152)	(35,603,609)	(36,462,522)	(37,798,884)	(39,008,868)	(40,263,536)
48	**Other AMI Benefits**																					
49	*Customer Benefits*																					
50	Reduced Consumption Inactive Premise	(18,723,974)	0	0	0	(1,520,988)	(2,200,686)	(2,328,557)	(2,340,666)	(2,352,837)	(2,365,072)	(2,377,370)	(2,389,733)	(2,402,159)	(2,414,651)	(2,427,207)	(2,439,828)	(2,452,515)	(2,465,268)	(2,478,088)	(2,490,974)	(2,503,927)
51	Reduced Uncollectible/Bad Debt	(5,232,600)	0	0	0	(425,055)	(615,003)	(650,738)	(654,122)	(657,524)	(660,943)	(664,380)	(667,835)	(671,307)	(674,798)	(678,307)	(681,834)	(685,380)	(688,944)	(692,526)	(696,127)	(699,747)
52	Reduction in Energy Theft	(47,052,180)	0	0	0	(3,822,149)	(5,530,187)	(5,851,520)	(5,881,948)	(5,912,534)	(5,943,279)	(5,974,184)	(6,005,250)	(6,036,477)	(6,067,867)	(6,099,420)	(6,131,137)	(6,163,018)	(6,195,066)	(6,227,280)	(6,259,662)	(6,292,213)
53	Customer Outage Reduction (CMO)	(18,066,119)	0	0	0	(1,183,507)	(1,764,710)	(1,924,299)	(1,993,405)	(2,064,992)	(2,139,150)	(2,215,971)	(2,295,551)	(2,377,989)	(2,463,387)	(2,551,852)	(2,643,494)	(2,738,428)	(2,836,770)	(2,938,644)	(3,044,177)	(3,153,499)
54	**Total O&M Costs**	114,611,604	648,144	6,929,497	11,433,061	13,457,234	12,699,841	11,173,534	11,142,068	11,364,910	11,592,208	11,824,052	12,060,532	12,301,743	12,547,779	11,599,587	11,831,578	12,068,210	12,309,574	12,555,765	12,806,881	13,063,018
55	**Total Non-Capital Benefits**	(400,525,970)	0	0	0	(22,066,350)	(38,651,014)	(45,145,510)	(46,955,544)	(48,170,357)	(49,226,615)	(50,719,455)	(52,149,924)	(53,575,951)	(54,914,428)	(56,503,236)	(58,061,988)	(59,528,671)	(60,772,062)	(62,501,463)	(64,113,256)	(65,778,719)
56	**Net Non-Capital Cost/(Benefit)**	(285,914,366)	648,144	6,929,497	11,433,061	(8,609,116)	(25,951,173)	(33,971,976)	(35,813,476)	(36,805,447)	(37,634,407)	(38,895,403)	(40,089,392)	(41,274,208)	(42,366,649)	(44,903,650)	(46,230,410)	(47,460,461)	(48,462,488)	(49,945,698)	(51,306,375)	(52,715,701)
57	**Overall Net Cost/(Benefit)**	**51,113,508**	**648,144**	**6,929,497**	**19,119,872**	**45,819,420**	**39,800,587**	**32,805,698**	**27,905,244**	**17,725,414**	**(3,338,366)**	**(6,563,252)**	**(9,188,697)**	**(12,045,264)**	**(15,069,904)**	**(18,951,821)**	**(21,943,878)**	**(25,220,420)**	**(27,607,520)**	**(31,009,727)**	**(35,760,793)**	**(38,482,014)**

Northern States Power Company

Attachment SJH-3
Samuel J. Hancock
Hearing Exhibit 108
IVVO Cost & Benefit Summary
Includes Escalation and Applicable Loaders
Cost/(Benefit)
Page 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
1		NPV	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2	Assets Installed		0	1,195	1,160	1,160	1,015	1,015	165	165	166	165	165	166	165	165	166	165	165	166	165	165
3	Cumulative Assets Installed		0	1,195	2,355	3,515	4,530	5,545	5,710	5,875	6,041	6,206	6,371	6,537	6,702	6,867	7,033	7,198	7,363	7,529	7,694	7,859
4	**Capital Items**																					
5	*Costs*																					
6	Assets and Installation	63,727,955	0	13,179,165	13,532,778	13,872,585	12,877,436	13,201,468	1,751,511	1,795,084	1,937,264	1,885,382	1,932,155	2,083,581	2,029,078	2,079,280	2,240,551	2,183,301	2,237,177	2,408,932	2,348,802	2,406,613
7	Assets and Installation - CON	9,662,977	0	2,169,005	2,220,223	2,271,832	2,013,737	2,060,924	184,051	188,632	239,991	198,125	203,043	257,602	213,232	218,510	276,470	229,446	235,111	296,683	246,847	252,925
8	Field Area Network (IVVO)	10,718,616	86,643	3,284,356	3,931,721	4,024,510	1,947,559	43,012	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	Field Area Network (IVVO) - CON	4,287,446	34,657	1,313,742	1,572,689	1,609,804	779,024	17,205	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	IT Systems and Integration	22,509,987	0	1,239,476	10,382,271	5,628,226	5,740,791	3,274,535	332,569	339,221	346,005	352,925	359,984	367,183	374,527	382,018	389,658	397,451	405,400	413,508	421,778	430,214
11	IT Systems and Integration - CON	6,752,996	0	371,843	3,114,681	1,688,468	1,722,237	982,360	99,771	101,766	103,802	105,878	107,995	110,155	112,358	114,605	116,897	119,235	121,620	124,052	126,534	129,064
12	IVVO Program Management	3,086,379	0	501,149	552,901	478,833	759,748	1,893,076	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	IVVO Change Management	4,312,853	0	881,019	1,362,937	1,176,319	1,121,934	1,049,008	0	0	0	0	0	0	0	0	0	0	0	0	0	0
14	IVVO Program & Change Management - CON	739,923	0	138,217	191,584	165,515	188,168	294,208	0	0	0	0	0	0	0	0	0	0	0	0	0	0
15	IVVO Integration (Personnel)	8,041,074	0	1,959,446	1,986,990	2,029,621	1,697,985	1,734,582	89,003	91,238	161,625	95,870	98,270	172,994	103,245	105,822	185,151	111,163	113,930	198,147	119,664	122,634
16	**Total Capital Costs**		121,301	25,037,417	38,848,776	32,945,714	28,848,619	24,550,377	2,456,906	2,515,941	2,788,686	2,638,180	2,701,447	2,991,516	2,832,440	2,900,235	3,208,728	3,040,598	3,113,238	3,441,322	3,263,625	3,341,450
17	**Net Revenue Requirement Impact**	141,826,320	0	0	0	12,525,616	21,479,443	25,108,763	25,424,417	24,550,756	18,070,449	15,891,241	14,297,295	14,243,242	14,172,675	14,087,223	14,020,495	13,949,514	13,867,200	13,805,604	12,522,867	12,357,088
18	**O&M Items**																					
19	*Costs*																					
20	Assets and Installation	20,429,473	0	317,161	325,660	840,661	1,316,016	1,836,621	1,953,713	2,361,382	2,466,770	2,575,430	2,687,448	2,802,918	2,921,931	3,044,583	3,170,973	3,301,200	3,435,369	3,573,583	3,715,952	3,862,586
21	Assets and Installation - CON	1,883,207	0	0	0	50,651	99,937	151,174	190,310	230,951	241,361	252,095	263,161	274,570	286,329	298,449	310,940	323,810	337,071	350,733	364,807	379,303
22	Field Area Network (AMI)	14,993,543	26,522	98,896	514,108	998,835	1,407,546	1,713,732	1,724,693	1,759,187	1,794,370	1,830,258	1,866,863	1,904,200	1,942,284	1,981,130	2,020,753	2,061,168	2,102,391	2,144,439	2,187,328	2,231,074
23	Field Area Network (AMI) - CON	5,997,417	10,609	39,558	205,643	399,534	563,018	685,493	689,877	703,675	717,748	732,103	746,745	761,680	776,914	792,452	808,301	824,467	840,956	857,775	874,931	892,430
24	IT Systems and Integration	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
25	IT Systems and Integration - CON	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
26	IVVO Program Management	340,714	0	51,000	62,424	53,060	86,595	209,775	0	0	0	0	0	0	0	0	0	0	0	0	0	0
27	IVVO Change Management	2,867,676	0	585,765	911,157	777,023	745,942	697,456	0	0	0	0	0	0	0	0	0	0	0	0	0	0
28	IVVO Program & Change Management - CON	320,839	0	63,676	97,358	83,008	83,254	90,723	0	0	0	0	0	0	0	0	0	0	0	0	0	0
29	*Energy & Capacity Benefits*																					
30	Fuel Savings (Avoided Energy)	(110,060,879)	0	0	0	(2,305,611)	(6,116,347)	(10,872,084)	(15,202,817)	(16,358,849)	(16,424,134)	(16,822,966)	(16,750,795)	(14,618,077)	(14,945,339)	(15,527,006)	(15,868,134)	(16,533,875)	(16,677,680)	(16,742,007)	(17,614,172)	(17,375,893)
31	Avoided Capacity, Trans, Dist Costs	(33,750,349)	0	0	0	(923,046)	(2,187,447)	(3,454,742)	(4,697,697)	(4,728,771)	(4,766,583)	(4,788,935)	(4,817,519)	(4,849,431)	(4,889,727)	(4,919,923)	(4,954,701)	(4,988,295)	(5,028,039)	(5,055,477)	(5,091,823)	(5,134,655)
32	**Total O&M Costs**	46,832,869	37,131	1,156,057	2,116,350	3,202,773	4,302,306	5,384,974	4,558,593	5,055,195	5,220,250	5,389,885	5,564,218	5,743,367	5,927,458	6,116,614	6,310,966	6,510,645	6,715,787	6,926,531	7,143,017	7,365,393
33	**Total Non-Capital Benefits**	(143,811,228)	0	0	0	(3,228,657)	(8,303,794)	(14,326,826)	(19,900,514)	(21,087,620)	(21,190,717)	(21,611,901)	(21,568,314)	(19,467,508)	(19,835,066)	(20,446,929)	(20,822,835)	(21,522,171)	(21,705,719)	(21,797,484)	(22,705,995)	(22,510,548)
34	**Net Non-Capital Cost/(Benefit)**	(96,978,358)	37,131	1,156,057	2,116,350	(25,884)	(4,001,488)	(8,941,851)	(15,341,921)	(16,032,425)	(15,970,468)	(16,222,016)	(16,004,097)	(13,724,141)	(13,907,608)	(14,330,315)	(14,511,869)	(15,011,526)	(14,989,932)	(14,870,953)	(15,562,978)	(15,145,155)
35	**Overall Net Cost/(Benefit)**	**44,847,962**	**37,131**	**1,156,057**	**2,116,350**	**12,499,731**	**17,477,956**	**16,166,911**	**10,082,496**	**8,518,331**	**2,099,982**	**(330,776)**	**(1,706,802)**	**519,101**	**265,067**	**(243,092)**	**(491,373)**	**(1,062,012)**	**(1,122,731)**	**(1,065,349)**	**(3,040,111)**	**(2,788,067)**

Attachment SJH-4
Samuel J. Hancock
Hearing Exhibit 108
CPCN Projects (AMI+IVVO) Cost & Benefit Summary
Includes Escalation and Applicable Loaders
Cost/(Benefit)
Page 1 of 1

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)	(q)	(r)	(s)	(t)	(u)	(v)
1		NPV	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
2	**Capital Items**																					
3	*Costs*																					
4	Assets and Installation	240,273,715	0	13,389,165	37,659,212	117,178,495	72,096,887	27,846,771	5,105,572	5,269,596	5,536,552	5,613,927	5,794,600	6,084,734	6,173,920	6,372,972	6,688,439	6,790,921	7,010,265	7,353,432	7,470,869	7,712,623
5	Assets and Installation - CON	24,748,347	0	2,190,005	4,364,846	10,991,661	7,076,090	3,420,752	462,030	476,594	538,294	507,141	523,155	589,211	556,750	574,364	645,103	611,318	630,696	706,474	671,355	692,678
6	Field Area Network (AMI+IVVO)	24,939,758	271,902	7,638,996	10,143,236	10,403,205	2,121,618	183,393	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	Field Area Network (AMI+IVVO) - CON	9,975,903	108,761	3,055,599	4,057,294	4,161,282	848,647	73,357	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	IT Systems and Integration	76,775,754	1,933,118	33,211,422	36,008,193	5,628,226	6,376,266	3,274,535	819,827	1,443,158	346,005	352,925	1,075,632	905,156	848,803	1,141,469	389,658	397,451	1,805,301	937,147	421,778	1,285,480
9	IT Systems and Integration - CON	54,251,461	1,650,826	28,730,737	25,055,290	1,688,468	2,264,915	982,360	577,374	1,107,226	103,802	105,878	719,138	637,468	586,634	763,155	116,897	119,235	1,392,062	647,691	126,534	859,436
10	Program Management	9,642,102	100,270	2,045,508	2,472,406	2,734,668	2,941,311	2,225,194	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	Change Management	9,103,047	61,833	1,836,766	3,104,822	3,104,467	2,295,782	1,248,562	0	0	0	0	0	0	0	0	0	0	0	0	0	0
12	Program & Change Management - CON	1,874,515	16,210	388,227	557,723	583,914	523,709	347,376	0	0	0	0	0	0	0	0	0	0	0	0	0	0
13	AMI/IVVO Operations (Personnel)	14,122,201	283,705	2,567,089	4,025,970	4,220,515	3,798,180	2,341,802	89,003	91,238	161,625	95,870	98,270	172,994	103,245	105,822	185,151	111,163	113,930	198,147	119,664	122,634
14	*Benefits*																					
15	Capital Benefits	(48,924,797)	0	0	0	(1,955,233)	(4,893,279)	(5,472,840)	(5,414,132)	(5,623,488)	(5,840,588)	(6,065,712)	(6,299,151)	(6,541,209)	(6,792,197)	(7,052,441)	(7,322,276)	(7,602,050)	(7,892,124)	(8,192,872)	(8,504,680)	(8,827,950)
16	**Total Capital Costs**		4,426,625	95,053,514	127,448,992	160,694,901	100,343,406	41,944,102	7,053,806	8,387,811	6,686,277	6,675,741	8,210,796	8,389,562	8,269,351	8,957,783	8,025,248	8,030,089	10,952,254	9,842,890	8,810,200	10,672,851
17	**Total Capital Benefits**		0	0	0	(1,955,233)	(4,893,279)	(5,472,840)	(5,414,132)	(5,623,488)	(5,840,588)	(6,065,712)	(6,299,151)	(6,541,209)	(6,792,197)	(7,052,441)	(7,322,276)	(7,602,050)	(7,892,124)	(8,192,872)	(8,504,680)	(8,827,950)
18	**Net Revenue Requirement Impact**	478,854,194	0	0	7,686,810	66,954,151	87,231,202	91,886,437	89,143,137	79,081,617	52,366,490	48,223,392	45,197,989	43,472,186	41,469,419	40,039,052	38,307,027	36,189,555	34,722,168	32,741,574	28,068,449	26,590,775
19	**O&M Items**																					
20	*Costs*																					
21	Assets and Installation	22,324,155	376,073	686,761	524,275	1,661,825	1,788,906	1,959,515	1,953,713	2,361,382	2,466,770	2,575,430	2,687,448	2,802,918	2,921,931	3,044,583	3,170,973	3,301,200	3,435,369	3,573,583	3,715,952	3,862,586
22	Assets and Installation - CON	2,037,456	0	36,960	19,861	132,767	147,226	163,463	190,310	230,951	241,361	252,095	263,161	274,570	286,329	298,449	310,940	323,810	337,071	350,733	364,807	379,303
23	Field Area Network (AMI+IVVO)	35,464,776	111,783	483,556	1,491,907	2,782,252	3,633,091	3,965,439	3,933,727	4,012,402	4,092,650	4,174,503	4,257,993	4,343,153	4,430,016	4,518,616	4,608,989	4,701,168	4,795,192	4,891,096	4,988,917	5,088,696
24	Field Area Network (AMI+IVVO) - CON	14,185,910	44,713	193,422	596,763	1,112,901	1,453,237	1,586,176	1,573,491	1,604,961	1,637,060	1,669,801	1,703,197	1,737,261	1,772,006	1,807,446	1,843,595	1,880,467	1,918,077	1,956,438	1,995,567	2,035,478
25	IT Systems and Integration	35,454,594	53,983	2,586,141	3,874,930	3,222,522	3,286,972	3,352,712	3,419,766	3,488,161	3,557,925	3,629,083	3,701,665	3,775,698	3,851,212	3,928,236	4,006,801	4,086,937	4,168,676	4,252,049	4,337,090	4,423,832
26	IT Systems and Integration - CON	33,791,980	46,100	2,355,061	3,639,229	3,087,075	3,148,817	3,211,793	3,276,029	3,341,550	3,408,381	3,476,548	3,546,079	3,617,001	3,689,341	3,763,128	3,838,390	3,915,158	3,993,461	4,073,330	4,154,797	4,237,893
27	AMI Operations (Personnel)	3,774,614	0	137,354	753,611	976,374	459,708	107,066	281,541	287,171	292,915	298,773	304,749	310,844	317,060	323,402	329,870	336,467	343,196	350,060	357,062	364,203
28	AMI O&M - CON	377,461	0	13,735	75,361	97,637	45,971	10,707	28,154	28,717	29,291	29,877	30,475	31,084	31,706	32,340	32,987	33,647	34,320	35,006	35,706	36,420
29	Program Management	1,062,862	10,000	224,400	270,504	307,750	324,730	242,898	0	0	0	0	0	0	0	0	0	0	0	0	0	0
30	Change Management	6,053,048	42,622	1,223,385	2,069,018	2,058,553	1,525,112	828,172	0	0	0	0	0	0	0	0	0	0	0	0	0	0
31	Program & Change Management - CON	706,663	0	144,779	233,952	236,630	184,984	107,107	0	0	0	0	0	0	0	0	0	0	0	0	0	0
32	Saver's Switch Program Costs	6,210,954	0	0	0	983,719	1,003,393	1,023,461	1,043,930	1,064,809	1,086,105	1,107,827	1,129,983	1,152,583	1,175,635	0	0	0	0	0	0	0
33	*Benefits*																					
34	AMI O&M Cost Reduction Benefits	(70,109,728)	0	0	0	(5,140,509)	(7,551,077)	(8,107,537)	(8,269,755)	(8,435,220)	(8,603,996)	(8,776,151)	(8,951,751)	(9,130,867)	(9,313,567)	(9,499,925)	(9,690,012)	(9,883,905)	(10,081,679)	(10,283,411)	(10,489,182)	(10,699,072)
35	AMI Customer Benefits	(89,074,873)	0	0	0	(6,951,700)	(10,110,586)	(10,755,115)	(10,870,140)	(10,987,887)	(11,108,444)	(11,231,905)	(11,358,368)	(11,487,932)	(11,620,702)	(11,756,786)	(11,896,293)	(12,039,341)	(12,186,048)	(12,336,539)	(12,490,940)	(12,649,386)
36	Avoided Energy Benefit	(110,060,879)	0	0	0	(2,305,611)	(6,116,347)	(10,872,084)	(15,202,817)	(16,358,849)	(16,424,134)	(16,822,966)	(16,750,795)	(14,618,077)	(14,945,339)	(15,527,006)	(15,868,134)	(16,533,875)	(16,677,680)	(16,742,007)	(17,614,172)	(17,375,893)
37	Avoided Capacity Benefit	(275,091,717)	0	0	0	(10,897,187)	(23,176,797)	(29,737,600)	(32,513,345)	(33,476,021)	(34,280,758)	(35,500,334)	(36,657,324)	(37,806,583)	(38,869,885)	(40,166,449)	(41,430,383)	(42,593,720)	(43,532,374)	(44,936,990)	(46,224,956)	(47,564,916)
38	**Total O&M Costs**	161,444,473	685,274	8,085,554	13,549,412	16,660,007	17,002,147	16,558,508	15,700,661	16,420,104	16,812,458	17,213,937	17,624,750	18,045,111	18,475,236	17,716,201	18,142,544	18,578,855	19,025,361	19,482,296	19,949,898	20,428,412
39	**Total Non-Capital Benefits**	(544,337,197)	0	0	0	(25,295,007)	(46,954,807)	(59,472,336)	(66,856,058)	(69,257,977)	(70,417,332)	(72,331,357)	(73,718,238)	(73,043,460)	(74,749,493)	(76,950,165)	(78,884,823)	(81,050,842)	(82,477,781)	(84,298,947)	(86,819,251)	(88,289,267)
40	**Net Non-Capital Cost/(Benefit)**	(382,892,724)	685,274	8,085,554	13,549,412	(8,635,000)	(29,952,660)	(42,913,828)	(51,155,397)	(52,837,872)	(53,604,875)	(55,117,420)	(56,093,488)	(54,998,349)	(56,274,257)	(59,233,965)	(60,742,279)	(62,471,987)	(63,452,419)	(64,816,651)	(66,869,353)	(67,860,856)
41	**Overall Net Cost/(Benefit)**	**95,961,469**	**685,274**	**8,085,554**	**21,236,222**	**58,319,151**	**57,278,542**	**48,972,610**	**37,987,740**	**26,243,744**	**(1,238,384)**	**(6,894,028)**	**(10,895,499)**	**(11,526,163)**	**(14,804,838)**	**(19,194,913)**	**(22,435,252)**	**(26,282,432)**	**(28,730,251)**	**(32,075,077)**	**(38,800,904)**	**(41,270,081)**

Modeling Customer Response to Xcel Energy's RD-TOU Rate

Privileged and Confidential

PRESENTED TO

Xcel Energy

PRESENTED BY

Ahmad Faruqui
Ryan Hledik

April 21, 2016

THE Brattle GROUP

Background

The purpose of this presentation is to describe our modeling of likely customer response to Xcel Energy's proposed RD-TOU rate design

The RD-TOU design features a demand charge, in addition to a fixed charge and an energy charge

In prior work on price response, we have used our PRISM modeling suite. The GREEN PRISM was used to analyze the impact of Xcel Energy's inclining block rates (IBR) in 2010. In work for other utilities, we have used the BLUE PRISM to analyze the impact of time-varying rates.

The methodology that we have used to model response to demand charges is an extension of this PRISM modeling framework

We model customer price response using three different approaches to capture the range of ways in which customers might response to a demand charge

Overview of methodology

We model three different ways in which customers could respond to Xcel's proposed rate offering

1) Arc-based approach. Customers are assumed to be aware that electricity costs more during the peak period and less during off-peak hours. The extent to which they shift load from peak hours to off-peak hours is based on the magnitude of the peak-to-off-peak price ratio and its relationship to price response as estimated in more than 40 residential pricing pilots.

2) System-based approach. Like the Arc-based approach, customers are assumed to respond to the new rate as if it were a time-of-use rate. Their response is estimated using a system of two demand equations. This modeling framework has been the basis for estimating peak load reductions in the context of AMI business cases in California, Maryland, Michigan, Florida, and Connecticut.

3) Pilot-based approach. Peak demand reductions are based directly on the average results of three residential demand charge pilots. These are the only three pilots that have quantified residential customer response specifically to demand rates. One of the pilots found specifically that customers respond similarly to demand charges and equivalent TOU rates.

In all three of these approaches, we account not only for the load shifting that will occur due to the new rate design, but also for a change in total consumption that is likely to occur as individual customers' average rates increase or decrease as a result of the new rate design.

Overview of methodology (cont'd)

Current Schedule R

	Charge
Service & facility charge ($/month)	6.75
Non-ECA riders ($/kWh)	0.012
ECA rider ($/kWh)	0.031
Energy - first 500 kWh ($/kWh)	0.046
Energy - 500+ kWh ($/kWh)	0.090

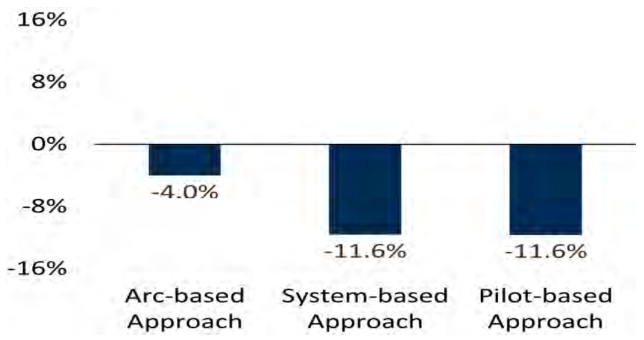
Proposed Schedule RD-TOU

	Charge
Service & facility charge ($/month)	9.53
Grid use ($/month)	14.56
Non-ECA riders ($/kW)	3.78
ECA rider - peak ($/kWh)	0.036
ECA rider - off-peak ($/kWh)	0.028
Energy ($/kWh)	0.005
Demand ($/kW)	7.88

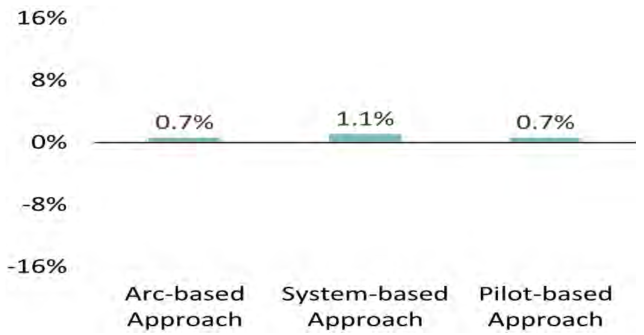
- For each of 200+ customers from Xcel Energy's load research sample, we compare the current Schedule R to the proposed Schedule RD-TOU on a monthly basis for calendar year 2013
- This allows for a comparison of today's two-part rate to a three-part rate that would be enabled by Xcel Energy's grid modernization proposal
- In the analysis, the charges in Schedule RD-TOU are modified to make the rate revenue neutral to the current Schedule R rate for the load research sample (those changes are not reflected in the tables above)

Overview of results

Change in Avg Peak Period Demand (Summer)



Change in Annual Electricity Consumption



Comments

- The results of all three approaches are relatively consistent
- Average peak demand reductions during summer months range from 4.0% to 11.6% across all customers
- Average annual energy consumption increases slightly; this is driven by a number of factors, including (1) that the average price of electricity decreases for most hours of the year for all customers and (2) the average daily rate decreases for large customers

Conclusions and recommendations

There is a substantial amount of empirical, theoretical, and intuitive support for the notion that customers will reduce peak demand with the introduction of a demand charge.

At the same time, the revenue neutral nature of the rate change means impacts on total electricity consumption are likely to be modest. Some customers will reduce total consumption in response to an average price increase and vice versa, but overall these are largely offsetting effects.

We recommend using the results of the System-based approach as a starting point for estimating system-level benefits of the new rate design. This is an internally-consistent modeling framework that has been adopted by regulatory commissions in other jurisdictions in the context of assessing the benefits and costs of grid modernization.

Methodology Detail

We use a hypothetical customer's June load profile when illustrating the three approaches

770 kWh of monthly electricity consumption

Time-differentiated consumption*

- 70 kWh on peak (weekdays, 2 pm to 6 pm)
- 700 kWh off peak

IBR tier-differentiated consumption

- 500 kWh first tier
- 270 kWh second tier

3.5 kW of maximum demand

- Measured during peak hours
- Load factor of 30%

* The timing of the peak period for measuring the demand charge billing determinant is different than the timing of the peak period in the ECA rider. In this example, we have shown the peak period of the demand charge. The peak/off-peak split for the ECA rider is 350 kWh/month (peak) and 420 kWh/month (off-peak)

Converting the RD-TOU rate into an all-in TOU rate

As a first step in the Arc-based and System-based approaches, the RD-TOU rate is converted into an all-in TOU rate

Proposed Schedule RD-TOU

	Charge	Quantity	Bill
Service & facility charge ($/month)	9.53	1	$9.53
Grid use ($/month)	14.56	1	$14.56
Non-ECA riders ($/kW)	3.78	3.5	$13.23
ECA rider - peak ($/kWh)	0.035698	350	$12.49
ECA rider - off-peak ($/kWh)	0.028109	420	$11.81
Energy ($/kWh)	0.004610	770	$3.55
Demand ($/kW)	7.880000	3.5	$27.58
		Total:	**$92.75**

Notes:
Customer is assumed to be in 500-1,000 kWh tier of grid use charge.
Peak period is defined above as 9 am to 9 pm, weekdays, consistent with the definition in the ECA rider.

Levelized Prices

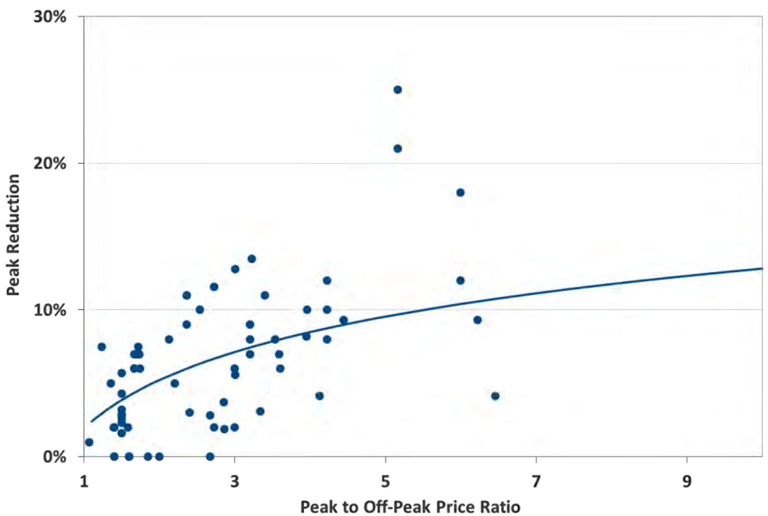
All-in Price	Peak	Off-Peak
Service & facility charge ($/kWh)	0.0130	0.0130
Grid use ($/kWh)	0.0199	0.0199
Non-ECA riders ($/kWh)	0.1518	0
ECA rider ($/kWh)	0.0357	0.0319
Energy ($/kWh)	0.0046	0.0046
Demand ($/kWh)	0.3165	0
Total ($/kWh)	**0.5415**	**0.0694**
All-in peak-to-off peak price ratio	**7.8**	

Notes:
Peak period is defined above as 2 pm to 6 pm, weekdays.
Due to a different peak definition in the ECA rider, the off-peak ECA rider price shown in the table is the load-weighted average of peak and off-peak ECA prices outside of the 2 pm to 6 pm window.

- Fixed charges are divided by the number of hours in the month and spread equally across all hours
- Demand charges are levelized and spread only across peak hours
- Volumetric charges remain unchanged

The Arc-based Approach

TOU Impacts Observed in Pricing Pilots



Note: Chart includes 67 data points from TOU pricing treatments without enabling technology.
The Arc was specified considering all 230 time-varying pricing treatments including CPP, VPP, PTR, and TOU.

Comments

- The results of 200+ pricing treatments across more than 40 pilots can be summarized according to the peak-to-off-peak price ratio of the rate and the associated measured peak reduction
- Focusing only on TOU pilots, we have fit a curve to these points to capture the relationship between price ratio and price response
- The drop in peak period usage can be read off the graph using the price ratio from the all-in TOU equivalent of the RD-TOU rate (as summarized on previous slide)
- For further discussion, see Ahmad Faruqui and Sanem Sergici, “Arcturus: International Evidence on Dynamic Pricing,” *The Electricity Journal*, August/September 2013.

The Arc-based Approach (cont'd)

Accounting for a Change in Average Price

Current Schedule R

	Charge	Quantity	Bill
Service & facility charge ($/month)	6.75	1	$6.75
Non-ECA riders ($/kWh)	0.01156	770	$8.90
ECA rider ($/kWh)	0.03128	770	$24.09
Energy - first 500 kWh ($/kWh)	0.04604	500	$23.02
Energy - 500+ kWh ($/kWh)	0.09000	270	$24.30
		Total:	**$87.06**

Proposed Schedule RD-TOU

	Charge	Quantity	Bill
Service & facility charge ($/month)	9.53	1	$9.53
Grid use ($/month)	14.56	1	$14.56
Non-ECA riders ($/kW)	3.78	3.5	$13.23
ECA rider - peak ($/kWh)	0.035698	350	$12.49
ECA rider - off-peak ($/kWh)	0.028109	420	$11.81
Energy ($/kWh)	0.004610	770	$3.55
Demand ($/kW)	7.880000	3.5	$27.58
		Total:	**$92.75**

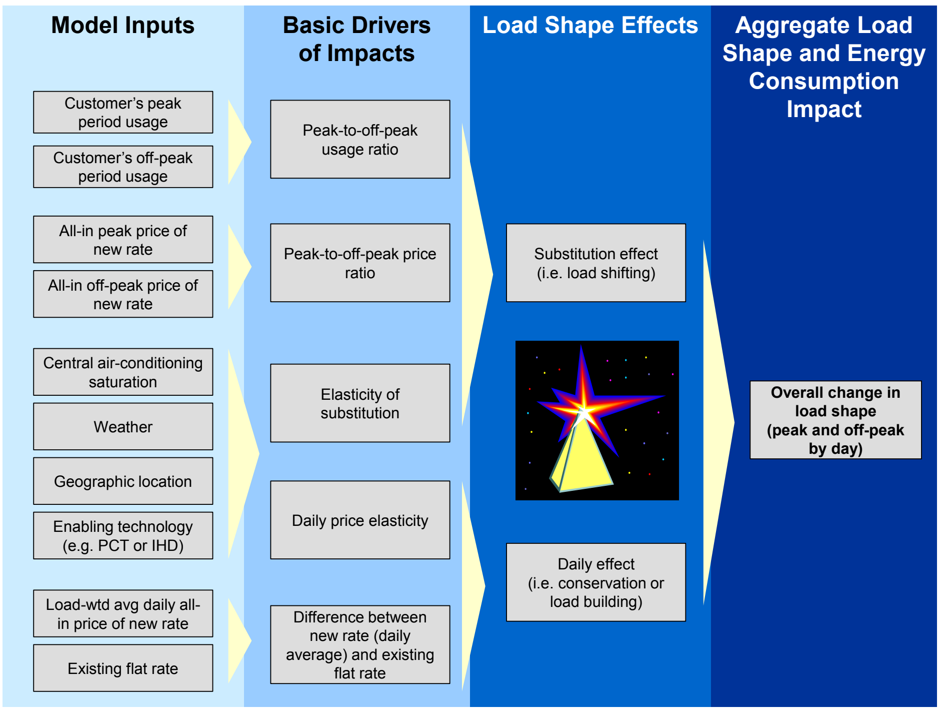
Notes:
Customer is assumed to be in 500-1,000 kWh tier of grid use charge.
Peak period is defined above as 9 am to 9 pm, weekdays, consistent with the definition in the ECA rider.

Comments

- The Arc-based Approach also accounts for customer response to a change in their average rate level
- For instance, if a customer's bill increases under the RD-TOU rate absent any change in consumption, that customer is likely to respond by reducing their overall energy use (including during the peak period)
- In this example, the hypothetical customer's total bill increases by 6.5% with the new rate
- Total electricity consumption would decrease as a result, based on an assumed price elasticity
- For example, with a price elasticity of -0.20, consumption would decrease by 1.3%
- We assume the same percentage change to consumption in all hours
- This effect is combined with the load shifting effect described on the previous slides to arrive at the composite change in load shape for each individual customer

The System-based Approach

Illustration of System-based Approach



Comments

- As an alternative to the two steps in the Arc-based Approach, the load shifting effect and the average price effect can be represented through a single system of two simultaneous demand equations
- The system of equations includes an “elasticity of substitution” and a “daily price elasticity” to account for these two effects
- There is support for this modeling framework in economic academic literature and it has been used to estimate customer response to time-varying rates in California, Connecticut, Florida, Maryland, and Michigan, among other jurisdictions
- In California and Maryland, the resulting estimates of peak demand reductions were used in utility AMI business cases that were ultimately approved by the respective state regulatory commissions

The Pilot-based Approach

In the Pilot-based Approach, the reduction in peak period demand is based on an average of the empirical results of the following three residential demand charge studies

Study	Location	Utility	Year(s)	# of participants	Monthly demand charge ($/kW)	Energy charge (cents/kWh)	Fixed charge ($/month)	Timing of demand measurement	Interval of demand measurement	Peak period	Estimated avg reduction in peak period consumption
1	Norway	Istad Nett AS	2006	443	10.28	3.4	12.10	Peak coincident	60 mins	7 am to 4 pm	5%
2	North Carolina	Duke Power	1978 - 1983	178	10.80	6.4	35.49	Peak coincident	30 mins	1 pm to 7 pm	17%
3	Wisconsin	Wisconsin Public Service	1977-1978	40	10.13	5.8	0.00	Peak coincident	15 mins	8 am to 5 pm	29%

Notes:
All prices shown have been inflated to 2014 dollars
In the Norwegian pilot, demand is determined in winter months (the utility is winter peaking) and then applied on a monthly basis throughout the year.
The Norwegian demand rate has been offered since 2000 and roughly 5 percent of customers have chosen to enroll in the rate.
In the Duke pilot, roughly 10% of those invited to participate in the pilot agreed to enroll in the demand rate.
The Duke rate was not revenue neutral - it included an additional cost for demand metering.
The Wisconsin demand charge is seasonal; the summer charge is presented here because the utility is summer peaking.

- Based on the results of these pilots, the average peak period demand reduction for each customer is assumed to be **14%** (impacts of the Norway and North Carolina pilots are derated when calculating this average, as described later)
- To estimate the change in total consumption, we account for the effect of the change in average price in the same way that it is accounted for in the Arc-based approach; this is combined with the peak impact described above

Price elasticities of demand

Price elasticities represent the extent to which customers change consumption in response to a change in price

We assume a price elasticity of -0.2 when estimating the average price effect, based on a review of price elasticities estimated by Xcel Energy and assumptions in prior Brattle work

The System-based Approach uses an elasticity of substitution of -0.14 and a daily price elasticity of -0.04

- The daily elasticity is based on California's "Zone 3" which we believe most closely represents the conditions of Xcel Energy's Colorado service territory. The elasticity of substitution is based on pilot results in Boulder.

Derating peak impacts

A recent time-varying pricing pilot by the Sacramento Municipal Utility District (SMUD) found that the average residential participant's peak reduction was smaller under opt-out deployment than under opt-in deployment

This is likely due to a lower level of awareness/engagement among participants in the opt-out deployment scenario (note that, due to higher enrollment rates in the opt-out deployment scenario, aggregate impacts are still larger)

Per-customer TOU impacts were **40% lower** when offered on an opt-out basis

The price elasticities in the Arc-based and System-based approaches are derived from pilots offered on an opt-in basis; since Xcel Energy is proposing to roll out the RD-TOU rate on a default or mandatory basis, we have derated the estimated impacts by 40% so that they are applicable to a full-scale default residential rate rollout

Similarly, in the Pilot-based Approach we derated the results of the Norway and North Carolina pilots by 40% since they both included opt-in participation. Results of the Wisconsin pilot were not derated, as we believe participation in that pilot was mandatory

Revenue neutrality

Several minor adjustments were made to the RD-TOU rate in order to make it revenue neutral to the current Schedule R rate for the load research sample

ECA rider

- Each customer's proposed ECA charge is multiplied by a constant so that revenue collected by the proposed ECA charge across all customers is equal to the revenue collected by the current ECA charge

Other riders (DSMCA, PCCA, CACJA, and TCA)

- Like the ECA rider, these charges in the RD-TOU rate are all scaled proportionally such that they produce in the aggregate the same revenue as the charges in the current rate

Production meter charge

- The production meter charge of $3.65/month is excluded from the RD-TOU rate to avoid accounting for the effect of a rate increase associated with advanced metering

Demand charge

- The demand charge remains unchanged relative to the rates provided by Xcel Energy

Energy charge

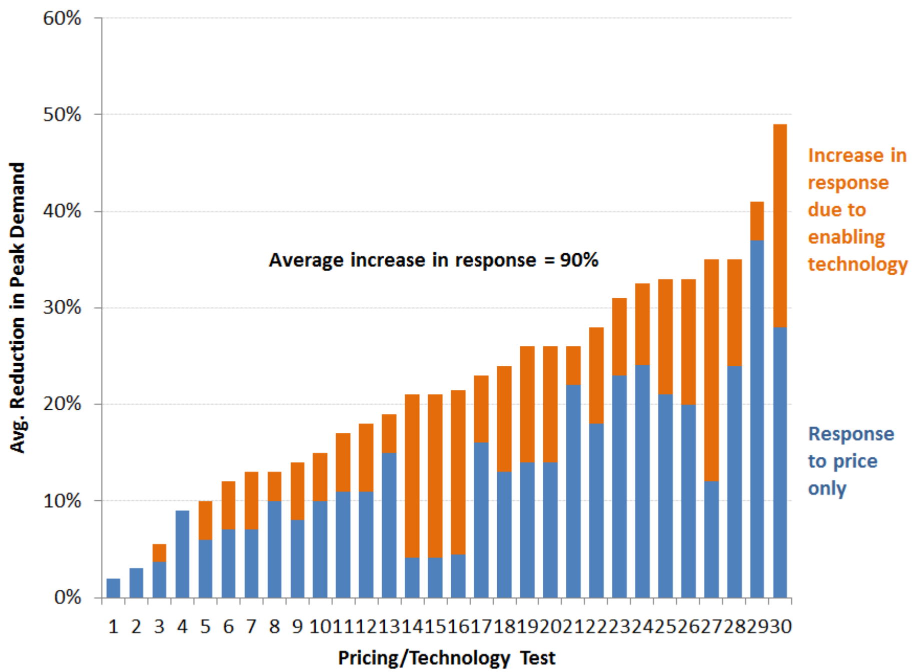
- The energy charge in the RD-TOU rate is adjusted to make up any remaining difference in revenue collected from the current rate and the proposed rate

Load research data

- Xcel Energy provided us with hourly load research data for 233 customers
- The hourly data covers the calendar year 2013
- In some cases, hourly observations were flagged in the dataset as meter reading errors – these were treated as “missing values” in our analysis.
- 15 customers were missing data for at least 5% of the hours in the year. These customers were removed from the sample.
- One customer had recorded usage of 0 kWh for over 60 consecutive days, but their usage was not flagged for errors. This customer was kept in the sample, and does not substantively impact the results.
- While the vast majority of customers had mean hourly usage of less than 5.8 kW, one customer had a mean hourly usage of 64 kW; this customer was flagged as an outlier and removed from the sample.
- After making all adjustments to the load research sample, we were left with 217 customers

The impact of technology

Price Response with and without Technology



Comments

- Note that our analysis accounts only for behavioral response to the new rate; it does not account for technology-enabled response
- The introduction of a demand charge will provide customers with an incentive to adopt technologies that will allow them to reduce their peak demand for bill savings; batteries, demand limiters, and smart thermostats are three such examples
- Technology has been shown to significantly boost price response (as shown at left) and could lead to larger peak demand reductions than we have estimated in this analysis

Results - Monthly Detail

Monthly change in class average peak period demand

	Arc-based Approach	Pilot-based Approach	System-based Approach
% Change Peak Demand	**-5.6%**	**-13.4%**	**-11.6%**
January	-6.0%	-13.9%	-11.8%
February	-6.9%	-14.8%	-11.8%
March	-6.7%	-14.7%	-11.9%
April	-7.7%	-15.8%	-11.4%
May	-8.1%	-16.1%	-11.5%
June	-4.4%	-12.0%	-11.5%
July	-2.4%	-10.2%	-11.1%
August	-3.7%	-11.4%	-11.3%
September	-6.4%	-13.6%	-12.9%
October	-7.5%	-15.6%	-11.5%
November	-7.2%	-15.0%	-12.1%
December	-5.4%	-13.4%	-11.5%

Monthly change in class annual energy consumption

	Arc-based Approach	Pilot-based Approach	System-based Approach
% Change Energy Use	**0.7%**	**0.7%**	**1.1%**
January	0.5%	0.5%	1.0%
February	-0.5%	-0.5%	0.7%
March	-0.3%	-0.3%	0.7%
April	-1.5%	-1.5%	0.6%
May	-1.9%	-1.9%	0.6%
June	2.2%	2.2%	1.6%
July	3.8%	3.8%	2.0%
August	2.8%	2.8%	1.8%
September	0.6%	0.6%	1.2%
October	-1.2%	-1.2%	0.6%
November	-0.5%	-0.5%	0.7%
December	1.0%	1.0%	1.1%

CERTIFICATE OF SERVICE

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

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

xx electronic filing

Docket No. E002/M-15-662

Dated this 16th day of September 2016

/s/
____
Lynnette Sweet
Regulatory Administrator

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April 18, 2016

—Via Electronic Filing—

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

RE: COST BENEFIT ANALYSIS
ALTERNATIVE RATE DESIGN
DOCKET NO. E002/M-15-662

Dear Mr. Wolf:

Northern States Power Company, doing business as Xcel Energy, submits to the Minnesota Public Utilities Commission the enclosed Cost Benefit Analysis in Response to the Commission's December 18, 2015 Order.

Our Cost Benefit Analysis provides detailed discussion on the key cost components of advanced metering infrastructure (AMI), and the benefits associated with implementing AMI. As noted in the enclosed Cost Benefit Analysis, we will provide a copy of our upcoming PSCo Grid Intelligence and Security Request for a Certificate of Public Convenience and Necessity after it has been filed with the Colorado Public Utilities Commission. This PSCo filing will provide more specific quantification of the costs and benefits to Xcel Energy, and will help inform the specific costs and benefits that could be experienced in Minnesota given existing equipment, MN Rules, and rate structures.

We have electronically filed this document with the Minnesota Public Utilities Commission, and copies have been served on the parties on the attached service list. Please contact Amber Hedlund at amber.r.hedlund@xcelenergy.com or (612) 337-2268, or me at amy.a.liberkowski@xcelenergy.com or (612) 330-6613 if you have any questions regarding this filing.

Sincerely,

/s/

AMY LIBERKOWSKI
MANAGER, REGULATORY ANALYSIS

Enclosure
c: Service List

1 ADVANCED METERING INFRASTRUCTURE

Xcel Energy is dedicated to providing its customers with safe, clean and reliable energy services they want and value at a competitive price. It also seeks to ensure that its customers have access to new tools and information that can allow for greater control of their energy usage and peak demand requirements. Like many utilities, as Xcel Energy strives to provide its customers with reliable service, it continues to face unprecedented operational challenges. The evolving distribution electric grid has newer types of loads and an increased penetration of distributed energy resources connected to systems that were designed to accommodate power flow in one direction. Advanced distribution management systems (ADMS) supported by an advanced metering infrastructure (AMI) will address this.

AMI may also support dynamic pricing and customers' capabilities to use advanced devices within this context, such as smart thermostats and plug-in-electric vehicles.

AMI will serve as a foundation for complementing technologies. Some of the technologies include:

- Advanced meters
- ADMS – Advanced Distribution Management System
- Intelligent distribution devices (Capacitor controls, Auto transfer switches, etc.)
- Intelligent customer devices (Smart thermostats, load control devices, etc.)
- Field area communications network (FAN) – Backhaul of data
- Meter data management systems (MDM) – Warehousing and managing of metering data
- Data analytics engine – Application used to apply smarts to data collected from field devices
- Customer web-portal- On-line access that allows customers to view and manage energy usage

The following are key cost components for AMI and associated systems:

- AMI meter and installation
- FAN communication equipment and installation
- IT systems and integration
- Program management
- AMI operations
- Technologies to support functionality for demand response/energy efficiency programs
- Distribution automation program costs

AMI benefits can be separated into three main categories:

- Direct Utility operational benefits
- Customer benefits from utility perspective
- Soft customer and operational benefits

Detailed discussions on costs and benefits follow in the subsequent sections.

2 AMI COST COMPONENTS

While pure installation costs for an AMI system can be determined based on a deployment schedule, in the industry an AMI cost and benefit analysis is conducted considering a 15-20 year period for AMI life-cycle.

2.1 AMI Meter and Installation

These are costs associated with purchasing and installing AMI meters. There are two main meter types, residential and commercial type meters. The cost of each type of meter and associated installation could vary depending on specific meter features and capabilities that are desired.

2.2 FAN equipment and Installation

Costs associated with purchasing and installing communication network components such as take-out points, repeaters, and preparation of poles to accommodate the attachment of such equipment. There are additional costs associated with setting up the communication infrastructure as well as integrating software applications required to manage various network components.

2.3 IT systems and integration

Costs associated with IT systems integration, hardware, software, IT security development, IT project management, labor, IT operations, asset management planning and meter data management system (MDM)

IT components include:

1. Maintenance of some of the infrastructure supporting two-way communication between central data collection engine and field networked devices e.g., meters, DA devices, etc.
2. Transfer of data from head-end to existing meter data management system (MDM). The data will be validated, edited, and estimated (if necessary) in the MDM. Extensive data analytics will be performed using data from the data warehouse using a new data analytics platform.
3. Maintenance of storage capability for AMI data. AMI will generate substantially more data, creating the need for robust, efficient data management tools and strategy.
4. Sharing of data between various applications, such as meter reading, billing, customer care, advanced distribution management system (ADMS), web portal, etc. This type of structure would require a supportive integration platform such as an enterprise service bus (ESB)
5. AMI data security planning and implementation to protect operational and customer data.

Below are further details on cost items:

- Hardware: These include servers that will need to store and manage meter and network data, servers to handle meter and data volume needed for data analytics platform, servers to handle meter and network data volume from AMI head-end and additional servers to support larger reading and data volume for MDM

- Software: Data analytics software platform implementation and annual licensing fee, AMI head-end software implementation
- Labor and project management: These are costs for MDM, AMI, other IT systems integration, AMI environment setup and install, data analytics tool, optimizing of processes and continued IT support for AMI systems.
- Contingency: Additional IT requirements identified during implementation.
- Asset management: Planning: IT efforts required to support AMI rollout
- MDM: Data warehousing and processing capabilities

2.4 Project Management

Project management costs associated with management, quality management, program scheduling and resource requirement, change control processes, issue and risk mitigation.

2.5 AMI Operations

Costs associated with metering operations, communications operations, facility ownership, and consumer education

2.6 Technologies to support Demand Response/Energy Efficiency Programs

Costs associated with implementing technologies that can support energy efficiency and demand response programs.

2.7 Distribution Automation Program Costs

Costs associated with implementing and maintaining distribution automation applications that leverage the FAN and AMI data.

2.8 Customer Out-reach costs

These are costs associated with customer education about grid modernization efforts and advanced meter benefits. Costs would also include sending mail to notify customers about AMI meter deployment plans, schedules, etc. Communication media includes: TV, radio, social media, etc.

3 AMI BENEFIT COMPONENTS

AMI benefits are also considered over a 15-20 AMI life-cycle. As discussed above there are three main categories of AMI benefits:

- Direct Utility operational benefits
- Customer benefits from utility perspective
- Soft customer and operational benefits

3.1 Direct Utility Operational Benefits

These benefits include:

- Reduced truck rolls for tasks such as outage/restoration confirms and for disconnects and reconnects
- Reduction in meter reading costs
- Reduction in field and meter services
- Reduction in unaccounted energy
- Efficiency improvement in customer care
- Improved efficiency of distribution system investments efficiency. Examples include:
  - Using AMI meters as distribution sensors
  - Aggregating AMI data to identify under-used and overloaded transformers
- Outage management efficiency improvement

3.1.1 Reduction in meter reading costs

These are benefits associated with reduction of manual meter reading employees and associated vehicle expenses. In NSP/MN, the Company currently has a read services contract with a third party to provide meter reading data through an Automated Meter Reading (AMR) fixed network system. Any potential benefit would be in the cost difference between an owned and operated AMI system and the current contract costs, not in manual reading.

3.1.2 Reduction in field and meter services

Benefits under this category include:

- Reduction in manual disconnect/ reconnect of meters
- Reduction in Manual off-cycle/special meter reads
- Reduction in nuisance stopped meter orders
- Reduction in customer equipment problem outages
- Reduction in " ok on arrival" outage field trips
- Reduction in field trips associated with voltage investigations
- Reduction in meter tests or investigations associated with high bill complaints or customer inquiries as customers would have the ability to review load profile data
- Use of AMI meter alarms would lead to a reduction in field trips to diagnose customer problems.
- AMI meters can also be remotely reconfigured and programmed to support rate changes without meter exchanges.

3.1.2.1 Reduction in manual disconnect/reconnect of meters

This benefit assumes all residential type meters would be equipped with remote disconnect switches. This would enable remote turning on/off of services resulting in significant labor and transportation cost savings. The savings for NSP/MN would be limited to the non -cold weather moratorium time frames and is subject to regulatory approval of remote disconnect and reconnect of residential meters.

3.1.2.2 Reduction in Manual off-cycle/special meter reads

These are reads performed during tenant changes, stop and start reads, re-reads, high bill inquiries and any other special circumstance that requires a meter reader to read a meter outside a normal read cycle.

3.1.2.3 Reduction in nuisance stopped meter orders

These are field trips associated with mistaken low or no consumption.

3.1.2.4 Reduction in customer equipment problem outages

With real-time remote access to metering data, costs associated with service crews dispatched for reasons not associated with company equipment can be reduced.

3.1.2.5 Reduction in "ok on arrival" outage field trips

Real-time remote access to outage information from the meter would eliminate service crew dispatch for outages where one does not exist or has already been restored.

3.1.2.6 Reduction in field trips associated with voltage investigations

Real-time access to metering data would lead to a reduction of crews dispatched to customer sites for voltage investigations. Without AMI, the practice is to install a temporary voltage recording meter for up to a week and then retrieve it (two trips) to validate voltage levels. With AMI, we'll be able to remotely interrogate the meter and validate the levels

3.1.3 Reduction in Unaccounted Energy

Industry organizations such as EPRI and EEI estimate that utilities lose about 1%-2% of revenue due to theft and other inaccuracies. AMI may be used as a tool in some cases to mitigate this.

3.1.4 Efficiency Improvement in Customer Care

Two-way communication will significantly reduce the amount of time call center agents would spend on responding to customer inquiries. Access to more immediate data will help address customer inquiries more promptly.

3.1.5 Advanced Distribution Management System (ADMS) Efficiency

AMI data can be aggregated at the transformer level and used to identify under-used and overloaded transformers as well as be used for sizing replacement transformers. AMI data can also be used by ADMS system modelling tools (used by distribution planners), load research and energy storage management forecasting. This is possible with a data analytics platform on top of AMI that would be used to manage performance of distribution functions.

As previously mentioned, AMI can serve as sensors, providing ADMS current insight into voltage levels throughout the system. This data will enable ADMS' voltage control algorithms to operate in the most optimal range as it controls voltage through capacitors and other controls.

3.1.5.1 Distribution Asset Management

AMI enables improvement in distribution system planning. By providing more granular historical load and outage data, AMI data can help in prioritizing of projects that seek to serve new growth as well as asset health projects that look to replacing distribution assets which have higher failure rates, thereby improving reliability and reducing O&M expenses.

3.1.5.2 Avoided meter purchases

These are incremental savings that would be realized relative to a base case of continuing business as usual with current meter failure rates and retirement rates compared to implementing AMI. AMI meters would be new and therefore would not require to be changed out for an extended period of time compared to existing meters that have been in the field.

3.1.6 Outage Management Efficiency

AMI will enable automated outage notification and restoration confirmation, providing a timely & accurate scope of an outage. This would enable more efficient dispatch of crews, allowing the company to optimize restoration resources by focusing on active outages, eliminating 'OK on arrival' outage calls, and dispatching crews relative to nested outage awareness. In addition, resource planning for escalated operations will be made with a more accurate outage profile across the system. This will result in more efficient and accurate resource acquisition and deployment strategies for escalated operations.

3.2 Customer Quantifiable Benefits

These are benefits to customers from a utility perspective that include:

- Reduced consumption on inactive meters
- Reduced uncollectible/bad debt expense
- Demand response
- Energy efficiency
- Service interruptions

3.2.1 Reduced Consumption on Inactive Meters

During customer move-in/outs, there is a period in which an electric meter is not associated with a customer. Consumption accrued during this period is not accounted for and is socialized amongst the whole customer base. With AMI, residential type premises will be able to be disconnected and reconnected remotely following current regulatory guidelines thus reducing unaccounted for consumption. These benefits would be limited during the cold weather moratorium due to the risk of property damage to heat affected premises.

3.2.2 Reduced Uncollectable/Bad Debt Expense

The Company incurs write-off expenses annually due to uncollected customer debt, which are included in rates paid by all customers. Because the current disconnect/reconnect process is manual in nature and in some cases not enough personnel are available to most efficiently complete these processes, the Company is not able to disconnect all non-paying customers. With AMI, disconnect/reconnect functions can be performed remotely following regulatory guidelines. This could also lead to increased customer satisfaction as the time to reconnect would significantly reduce.

3.2.3 Demand Response

AMI meters will inherently be capable of measuring, storing and reporting peak demand and energy usage by time intervals. Together with appropriate web portals, rates and programs, such information can improve customers' understanding of their load requirements and enable pricing incentives for customer action to reduce demand.

3.2.4 Energy Efficiency

With AMI, customers could have access to usage data that would enable more informed decisions on their energy usage.

3.2.5 Customer Outage Reduction

AMI would enable quicker responses to customer outages to minimize the risk of economic losses that could be experienced by the customer.

3.2.6 Momentary Outage

With AMI and complementing technologies, such as advanced outage management systems and IT systems, the utility is able to determine exact moments customers experience momentary outages. That information would be instrumental in measuring momentary average interruption frequency index (MAIFI).

3.3 Customer and Societal Soft Benefits

3.3.1 Distributed Energy Monitoring

With increased penetration of Distributed Energy Resources, near real-time visibility to AMI data would be instrumental for operational needs to ensure safe and resilient operation of the distribution grid.

3.3.2 Safety and Emergency Response

AMI could improve safety by reducing or eliminating certain physical customer visits: Such trips would include disconnect/reconnect functions, meter reading, traditional meter exchanges, etc. The remote disconnect feature could also be used in emergency response situations to shut-off customer premises.

3.3.3 Support for Plug-in Electric Vehicles

AMI provides an infrastructure that could be leveraged to better support and integrate PEV loads and charging controls. This may enable or improve the efficiency of providing pricing incentives to manage usage and provide demand response to reduce system costs and improve grid stability.

3.3.4 Environmental Benefits

By providing an infrastructure that supports energy conservation efforts and pricing that is time-based or renewable source-based, AMI could lead to a reduction of fossil fuel emissions. Remote operational features supported by AMI, such as remote connect/disconnect, would enable the utility reduce number of truck-rolls hence a reduction in carbon emissions.

3.3.5 Support for New Customer Services

AMI provides a prerequisite infrastructure to provide customers with a wider range of optional rate offerings that could be easier to manage.

3.3.6 Hot Socket Detection Capability

With AMI and a Meter Data Management system, the Company will be able to perform data analytics on temperature information retrieved from AMI meters to detect defective sockets.

4 COSTS AND BENEFITS UTILITY FILINGS

The Company has not completed a cost and benefit analysis on an AMI infrastructure investment in NSPM. To provide some quantification of costs and benefits, the Company relied on information that will soon be available from the PSCo jurisdiction and the below information on publicly available costs and benefits as filed by other utilities was located through internet searches.

4.1 Xcel Energy (Public Service Company of Colorado)

The Company anticipates making a grid intelligence and security request for a certificate of public convenience and necessity (Grid CPCN) filing in the PSCo jurisdiction in the next couple of months. This Grid CPCN will present and address the cost and benefit analysis for Colorado customers of making an investment in AMI infrastructure. This filing will help inform the specific costs and benefits that would be experienced in Minnesota given existing equipment, MN Rules, and rate structures. The Company will file a copy of the Grid CPCN in this docket when it is available.

4.2 Ameren Illinois (Electric Only)[1]

Project overview:

- Electric deployment
- Initial meter count of 780, 419
- Cost is based on 62% deployment
- Annual growth rate of 0.25%
- Deployment of eight years

Key Cost Components (in $ millions, over 20 years):

Key Cost Components	Capital	O&M	Total
AMI Meter and Communications Infrastructure and Implementation	$129	$0	$129
IT Systems and Integration	$111	$183	$294
Project Management	$16	$0	$16
AMI Operations	$16	$53	$69
Manual Methods to Meet Performance Metrics	$0	$5	$5
Demand Response/Energy Efficiency Program Costs	$0	$53	$53
Total	**$272**	**$294**	**$566**

Key Benefit Drivers (in $ millions, over 20 years):

Benefit Category	Cumulative Benefits
Reduction in Meter Reading Costs	$238
Reduction in Field & Meter Services	$209
Reduction in Unaccounted for Energy	$41
Efficiency Improvement in Customer Care	$15
IT Cost Savings	$5
Improved Distribution System Spend Efficiency	$42
Outage Management Efficiency	$32
Total	**$582**

Quantified Customer Benefit Breakout (in $ millions, over 20 years)

Quantified Customer Benefits	Cumulative Benefits
Reduced Consumption on Inactive Meters	$17
Reduced Uncollectible / Bad Debt Expense	$59
Demand Response	$406
Energy Efficiency	$24
PEV	$151
Carbon Reduction	$11
Customer Outage Reduction Benefit	$28
Total	**$695**

[1] As filed by Ameren Illinois Company in Docket No. 12-0244, Advanced Metering Infrastructure (AMI) Cost/Benefit Analysis, EXHIBIT 3.1, June 28, 2012.

CERTIFICATE OF SERVICE

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

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

xx electronic filing

Docket No. E002/M-15-662

Dated this 18th day of April 2016

/s/

Jim Erickson
Regulatory Administrator

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