Direct Testimony and Schedules
Ravikrishna Duggirala

Before the Minnesota Public Utilities Commission
State of Minnesota

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

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

Advanced Grid Cost Benefit Analysis

November 1, 2019

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Schedules

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

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

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

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

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

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

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

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

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

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

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

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

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

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

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

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

initiative, but a comprehensive assessment requires consideration of additional factors that are discussed by the Company's other AGIS witnesses.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

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

- Section II: AGIS Quantitative Cost Benefit Model
- Section III: Least-Cost/Best-Fit Alternatives
- Section IV: Qualitative Benefits of AGIS
- Section V: Conclusion

II. AGIS QUANTITATIVE COST BENEFIT MODEL

A. Model Structure and Requirements

Q. WHAT IS THE PURPOSE OF THE AGIS CBA, FROM THE COMPANY'S PERSPECTIVE?

A. The Company is presenting its CBA to illustrate its assessments of the quantitative value of the requirements for and benefits of the AGIS initiative. This model is intended to aid the Commission and other stakeholders in evaluating the overall prudence of the AGIS proposals, and was likewise required by the Commission's Order Point 9.B in its Order Authorizing Rider Recovery, Setting Return on Equity, and Setting Filing Requirements, dated September 27, 2019 in our 2017 Transmission Cost Recovery (TCR) rider (Docket No. E002/M-17-797) (TCR Rider Order).

Q. PLEASE INTRODUCE THE COMPANY'S COST BENEFIT MODEL IN THIS MATTER.

A. The CBA model compares the costs with the quantifiable benefits of each component of the Company's AGIS initiative, as well as the overall costs and quantifiable benefits of the initiative. More specifically, the model calculates the benefit-to-cost ratios for the proposed components of the AGIS initiative that the Company is planning to pursue at this time – namely, AMI, FLISR, and IVVO. The cost components of the FAN are also incorporated into the CBA because the FAN benefits are realized through its support of the other components of the AGIS initiative. The CBA utilizes specific cost and quantifiable benefit estimates and assumptions provided by Company witnesses Mr. Gersack, Ms. Bloch, Mr. Harkness, and Mr. Cardenas. I also support certain benefits, as discussed later in my Direct Testimony.

The Company's CBA model utilizes the Discounted Cash Flow (DCF) procedure and the 2019 Net Present Value (NPV) for quantifiable costs and benefits, to determine the value of the AGIS investments. Specifically, the benefit-to-cost ratio evaluates the standalone costs and benefits of each of AMI, IVVO, and FLISR respectively, including the FAN costs allocated to each of these components. Finally, the model evaluates the NPV benefit-to-cost ratio for AMI, IVVO, and FLISR on a combined basis.

Q. HOW WAS THE COST BENEFIT MODEL DEVELOPED?

A. The structure and form of the CBA are consistent with the Company's general approach to CBAs, including the CBA provided to the Colorado Public Utilities Commission in our Public Service Company of Colorado AGIS Certificate of Public Convenience and Necessity (CPCN) proceeding. (That matter, Proceeding No. 16A-0588E, resulted in an unopposed settlement approving the Company's need for the components of AGIS for which it needed a CPCN.) In structuring the CBA for grid modernization investments specifically, we also looked at similar analyses conducted by others for similar types of assets. For example, our framework is similar to that used by Ameren Illinois in their grid modernization efforts. We also considered the Electric Power Research Institute (EPRI's) technical report on Estimating the Costs and Benefits of the Smart Grid.[2]

Q. WHY DID THE COMPANY SELECT THIS FORM OF QUANTITATIVE MODEL?

A. This CBA is just one phase of a much more extensive assessment performed by the Company prior to seeking Commission approval for the four AGIS components presented in this case. This assessment included evaluation of the needs and goals of our distribution system, customers, the Commission, and other stakeholders, and then assessments of the alternatives to meet those needs and goals. These processes are described in detail in the testimony of Company witnesses Mr. Gersack, Ms. Bloch, Mr. Cardenas, and Mr. Harkness. (For example, Ms. Bloch and Mr. Cardenas explain the status of the current meters on our system and the extensive planning, information gathering, RFP processes, and consideration of alternate vendors, devices, systems, and programs that we undertook prior to selecting our current AMI plan.[3]) Now, as we are at the point of proposing our overall strategy and plan to the Commission, we provide this cost benefit model to identify and discuss the cost-effectiveness of the components of that plan (including the avoided costs of necessary alternative solutions) and of the total AGIS initiative.

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[2] https://www.smartgrid.gov/files/Estimating_Costs_Benefits_Smart_Grid_Preliminary_Estimate_In_201103.pdf.

[3] To the extent it makes sense, I have summarized these considerations in the least-cost/best-fit segment later in my testimony, which illustrates our conclusions with respect to alternatives to AMI and the FAN.

Q. HOW DID THE COMPANY STRUCTURE THE CBA PRESENTED IN YOUR TESTIMONY?

A. The model compares the upfront and ongoing project implementation costs (including planning and installation), as well as avoided costs, against the quantifiable benefits of the Company's proposed project over the analysis period. The model incorporates the Distribution costs and Customer Care costs of the systems, as well as the Business Systems costs required for the implementation of the projects, including integration, software-hardware, project management, and other costs in order to provide a complete picture of AGIS initiative costs.

Further, the model views costs and benefits from the customer perspective, meaning that it quantifies the estimated net impact of costs and savings to customers, including Commission-approved measures of societal benefits.[4] In this respect, all quantifiable utility costs and benefits were estimated in the model as they would be effectuated through utility electric rates. For example, the Company estimated the total cost of meter installation and operation in terms of revenue requirements.

We also estimated reasonably quantifiable direct customer benefits of improvements in the Company's electric service. These benefits can take many different forms, such as cost savings in system management or reduced energy and generation needs that benefit the customer through rates; pricing opportunities for customers through time-of-use rates; reduced outage impacts to customers' own activities; and avoidance of lost revenue through

[4] For example, carbon dioxide emission reductions can be measured and quantified via the Commission-ordered externality values.

meter tampering. In measuring such benefits, we took into account past Commission determinations of value (as with the social cost of carbon, as described in my testimony) and feedback on previous submissions (as with the CMO values, as described in Ms. Bloch's testimony).

Q. ONCE THE QUANTIFIABLE COSTS AND BENEFITS FROM THE OTHER WITNESSES ARE IN THE MODEL, WHAT CALCULATIONS DOES THE MODEL MAKE TO ESTIMATE THE CUSTOMER IMPACT?

A. First, it is necessary to take the projected capital costs and benefits and estimate a net capital revenue requirement. The net capital revenue requirement is the aggregate impact of both the capital costs and the capital savings over the analysis period. Therefore, the net capital revenue requirement estimates how the capital related costs and benefits would impact the customer through electric rates.

The model takes the annual capital costs and capital benefits and makes assumptions regarding how those costs and benefits may be reflected in rate base, and estimates a net capital revenue requirement as a function of depreciable book and tax lives for the assets, as well as the Company's weighted average costs of capital (WACC) and tax rates. The estimated net revenue requirement associated with the capital costs and benefits represents the annual impact of the capital spend, which is how the Company would calculate electric rate recovery on the underlying investment.

Second, for O&M costs and savings, fuel savings, and other benefits, the model assumes that those costs and benefits would be expensed or earned in the year they were incurred, and are embedded in the Company's electric rates. Any such changes will flow through to the customers.

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

A. Once the stream of the net capital revenue requirements, O&M costs and benefits are calculated, the streams are compared on an NPV basis. Each stream of costs or benefits is present-valued back to 2019 dollars utilizing the Company's WACC as a discount rate. Then, by dividing the net present value of benefits by the net present value of costs, a benefit-to-cost ratio is calculated. A benefit-to-cost ratio of 1.0 indicates benefits of that component of the AGIS initiative – or of the overall initiative – equal costs; a ratio of less than 1.0 means costs exceed benefits; and a ratio of greater than 1.0 means benefits exceed costs.

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

A. The model for AMI (including the TOU Pilot) examines the period beginning in 2019 and ending 2035. The period for IVVO and FLISR is longer (2019 through 2038), due to the longer useful life of the underlying assets.

Q. WHY DOES THE MODEL EXAMINE THESE PERIODS OF TIME?

A. For AMI, the model reflects the current phase of work beginning in 2019, and future installation phases beginning in 2021, as described by Ms. Bloch. This includes the assumption that AMI meters and associated software and hardware, as well as the necessary components of the FAN will begin depreciation upon installation. It also includes the meters we are installing for 2019 and 2020 for the TOU pilot evaluation period, which will subsequently be replaced with meters with Distributed Intelligence capabilities at no cost to the Company or customers.

While additional meters will be installed after 2021, the IT components will need to be in place by the time of the initial meter installations in order for the system to function. Thus by 2035 (after the fifteen-year period from 2021-2035), the network will be fully depreciated. Additionally, while the potential service life of AMI meters is between 15 and 20 years in the industry, we have utilized a fifteen-year period for AMI examination. This is consistent with the 15-year depreciation terms presently approved by the Commission for our existing automated meter reading (AMR) meters and reflects the challenging climate in Minnesota.

As Ms. Bloch further describes, the FLISR and IVVO assets are expected to have a 20-year life. The twenty-year life for IVVO and FLISR follows the industry standard for the life cycle evaluation of similar projects. While FLISR and IVVO devices will be installed beginning in 2020 and 2021 respectively, as with AMI the underlying IT systems must be in place before device installation. As a result, the 2019-2038 IVVO and FLISR CBA timelines capture the estimated costs and benefits from installation for the projected life of the system.

While some of the distribution assets installed may be useful beyond this timeframe, overall, our timeframes are intended to be conservative and therefore support a conservative assessment of total benefits and costs.

Q. CAN YOU PROVIDE MORE INFORMATION ON HOW THE COMPANY DEVELOPED THE COST AND BENEFIT INPUTS INTO THE MODEL?

A. Yes. The capital and O&M costs and benefits of AMI (including the TOU pilot), FLISR, and IVVO, including the associated FAN components, were determined by our Customer Care, Business Systems, and Distribution areas (including business area financial teams), with additional support from the AGIS Program Management Office, as discussed in more detail below. Our Program Management Office, Risk Management, and the Regulatory Department coordinated and developed modeling assumptions consistent with these cost and benefit estimates. The testimonies of Mr. Gersack, Ms. Bloch, Mr. Harkness, and Mr. Cardenas provide detail regarding the cost and benefit assumptions for each component of the AGIS projects, while I summarize those model inputs and provide explanations on the overall results of our CBAs.

Q. WHY DO YOU REFER TO AMI, FLISR, AND IVVO COSTS AND BENEFITS AS "INCLUDING THE ASSOCIATED FAN COMPONENTS"?

A. As Company witnesses Ms. Bloch and Mr. Harkness discuss in their Direct Testimony, the FAN will be a single, general-purpose, field area wireless networking resource that enables two-way communication of information and data to and from infrastructure at the Company's substations and the field devices. The FAN will provide the necessary communication capacity for the AGIS initiative, while also ensuring that the data being transmitted is secure. However, the FAN is not a standalone program and does not provide benefits on its own; rather, it is the communications network to enable AMI, IVVO, and FLISR functionality and provide their respective benefits to customers.

As such, we have incorporated FAN costs into the models for AMI, FLISR, and IVVO.

Q. HOW WERE THE FAN COMPONENTS THEN INCORPORATED INTO THE MODEL?

A. The model allocated FAN costs across the analyses for the individual AGIS components the FAN serves. Specifically, as explained by Mr. Harkness in his Direct Testimony, the FAN structure is primarily made up of two technological modules: WiMAX and WiSUN. WiMAX (Worldwide Interoperability for Microwave Access) is used to transfer data over different transmission modes such as point to point and multipoint modes. WiSUN (Smart Utility Network) is a low rate wireless system that must be in place to enable AMI device-to-device and device-to-headend communication. Because AMI is the predominant beneficiary of the WiSUN system, WiSUN costs have been completely allocated to AMI.

The meters and repeaters that constitute the AMI, the IVVO capacitors and voltage monitors, and the FLISR reclosers will each have embedded communication modules that will allow them to communicate directly with the FAN's access points on the WiMAX core infrastructure. But while the WiMAX system will provide coverage for all of NSPM's service territory, including 1050 feeders that all will contain AMI meters, Ms. Bloch explains that only a subset of the feeder population will have FLISR and IVVO equipment installed. Specifically, FLISR equipment will be initially installed on 208 feeders, while IVVO will be installed on 189 feeders. Likewise, each program will benefit from the communication system based proportionally on the amount of data needed and transferred. WiMAX costs are therefore distributed between AMI, FLISR, and IVVO according to the number of devices in proportion to the number of feeders.

Based on the total number of devices installed by feeder for each program, and given that additional devices affecting the WiMAX component may be installed in the future for both IVVO and FLISR, the business has estimated an allocation to capture that growth of AMI at 80 percent, IVVO at 5 percent, and FLISR at 15 percent. These percentages are also consistent with the total initial capital investment required by each program.

Consequently, the AMI, IVVO, FLISR, and consolidated models assume implementation of the FAN from 2019 through 2024, consistent with the timeline to subsequently implement the AMI meters, IVVO, and FLISR assets.

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

A. Yes. As described by Company witness Mr. Harkness, IT efforts include the costs of integrating the components of the AGIS initiative with existing Company back-end applications that will utilize the data. Similarly, IT efforts are necessary to ensure the security of the data collected and transmitted from advanced metering. As with the FAN, IT work is not a standalone program that provides benefits on its own; rather, it is a necessary component of the AGIS programs. Therefore, the costs of IT efforts for AMI, FLISR, and IVVO are included in the cost benefit model for these components.

Q. WHY IS THE CBA FOCUSED ON AMI (INCLUDING THE TOU PILOT), FLISR, AND IVVO, WITH ASSOCIATED COMPONENTS OF THE FAN?

A. These are the components of the AGIS initiative that are forward-looking, and which the Company plans to undertake as an integrated plan for the advancement of our distribution system. While they build on the Advanced Distribution Management System (ADMS), the ADMS was previously approved by the Commission through Docket No. E002/M-15-962 under Minn. Stat. § 216B.2425, before other components of the AGIS initiative were submitted or approved, and is necessary regardless of other selected advanced grid efforts. Consequently, the CBA is structured to aid the Commission's decision-making for the future, both from rate recovery and Integrated Distribution Planning (IDP) perspectives.

Q. HOW WERE THE MODEL'S COST AND BENEFITS INPUTS DETERMINED FOR THE FIRST FIVE-YEAR PERIOD, FROM 2019 THROUGH 2023?

A. Each subject matter expert provided estimated capital and O&M costs and benefits in 2019 dollars, by year, for the period 2019 through 2023. The dollars for 2020-2022 align with the Company's multi-year rate plan (MYRP) in this proceeding (plus one year).

These costs and benefits, except for fixed price items, were then converted into nominal dollars within the model using assumptions for labor and non-labor inflation over the analysis period.

Q. How were the model's cost and benefits inputs determined for 2024 through 2038?

A. The additional capital and O&M costs beyond 2023 were estimated for each respective part of the project through 2035 for AMI and 2038 for IVVO and FLISR, in order to capture the costs and benefits of each of the programs beyond the initial implementation period. These O&M and capital costs were provided in 2019 dollars by or at the direction of Company witnesses Mr. Gersack, Ms. Bloch, and Mr. Harkness, and were escalated to nominal dollars for either the full twenty-year (FLISR, IVVO) or fifteen-year (AMI) analysis period.

Benefits were also estimated for this period based on when we expect customers to experience these benefits, including continued escalation of benefits beginning in 2023 or earlier to the appropriate future year.

Q. Have the costs listed in the model been correlated to the Company's rate case budget?

A. Yes. My group worked closely with the Financial Planning area to ensure that the two are consistent. However, it is important to be clear that there are some differences in how the numbers are presented. In particular, the analysis is based on net present value of revenue requirements, with capital investment costs captured in the year the investment is in service and costs stated in 2019 dollars. The MYRP budgets presented by other AGIS witnesses are stated in annual capital expenditure and capital addition dollars. As a result, the numbers in the CBA correspond to the rate case budgets but will not look exactly the same.

Q. HOW ARE THE COSTS IN THE MODEL CATEGORIZED?

A. It is possible to review the costs in the model from several perspectives. The costs, which are set forth in Exhibit___(RD-1), Schedules 2, 3, 4 and 5 of my Direct Testimony, are identified as:

- Rate case budgets to the extent they are for the years of the Company's MYRP, or longer-range planning costs for the years after 2022;
- Either capital or O&M;
- Either Business Systems or Distribution costs; and
- Direct, Indirect, Tangible, or Intangible costs, consistent with Order Point A.3 in the Commission's September 27, 2019 TCR Rider Order.

Q. PLEASE PROVIDE THE COMPANY'S DEFINITIONS OF DIRECT, INDIRECT, TANGIBLE, INTANGIBLE, AND "REAL" COSTS FOR PURPOSES OF ITS AGIS INITIATIVE.

A. The Company defines these categories of costs as follows:

- *Direct costs* – the cost of the materials and the workers that are involved when a company makes a particular product or provides a particular service that can be easily traced to that product, department, or project – similar to costs that are assigned rather than allocated.
- *Indirect costs* – a cost that cannot be directly traced to a particular product, department, activity, project, or providing a particular service – similar to overhead, or costs that are allocated rather than assigned.
- *Tangible costs* – Like direct costs, a tangible cost (or benefit) is a quantifiable cost related to an identifiable source or asset. It can be directly connected to a material item used to conduct operations or run a business. Tangible costs represent expenses arising from such things

as purchasing materials, paying employees or renting equipment. The costs in the CBA are tangible.

- *Intangible costs* – an unquantifiable cost (or benefit) relating to an identifiable source. Intangible costs represent a variety of expenses such as losses in productivity, customer goodwill, drops in employee morale, or damage to corporate reputation. Most qualitative costs and benefits are intangible, although the Company has chosen not to assign a dollar value to some potentially tangible costs (like human safety).
- *Real costs* – total costs the utility incurs to produce a good or service or to implement a program, including the cost of all resources used and the cost of not employing those resources in alternative uses. Real costs analysis gives a greater picture of a product and the spending associated with it. The CBA model is intended to identify Real Costs throughout.

These categories do at times overlap, as most tangible costs are also assigned or allocated and are therefore either an Indirect or Direct cost. Where overlap occurs in the Company's AGIS modeling, both categories are identified.

Q. ARE INTERNAL AND EXTERNAL LABOR COSTS INCLUDED IN THE COSTS OF EACH COMPONENT OF THE AGIS INITIATIVE INCLUDED IN THE MODEL?

A. Yes. As Mr. Gersack discusses, both the model and our overall support for the AGIS initiative in this proceeding are intended to capture the "all-in" costs of the project. Further, the Company is seeking base rate recovery for project costs being incurred or placed-in service during the MYRP; therefore, it is appropriate to include both internal and external labor costs. The support for these costs is provided by Ms. Bloch and Mr. Harkness.

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

A. Yes. In addition to the cost estimates, the Distribution and Business Systems areas developed contingency estimates for each aspect of the project that warranted a contingency. These contingency estimates are depicted on Exhibit___(RD-1), Schedule 2 (AMI CBA Summary), Schedule 3 (FLISR CBA Summary), and Schedule 4 (IVVO CBA Summary) as cost line items. Since by definition the amount and type of contingency dollars that will actually be spent cannot be wholly defined up front, the Company prepared CBAs summaries for each component both with and without contingency dollars, to provide insight into how the range of potential contingency amounts could affect the overall benefit-cost ratio. The testimonies of Ms. Bloch, Mr. Harkness, and Mr. Gersack provide additional support for the contingency amounts included in the CBA.

Q. HOW WERE THE ESTIMATES OF CONTINGENCY FOR EACH WORK STREAM INTEGRATED INTO THE MODEL?

A. The estimates of contingency were added to the estimated costs of the project and input into the model as a cost. In essence, the model evaluates the cost of the project as if the Company needed to spend up to the full contingency amounts or none of the contingency. This allows both the most conservative view of potential benefit-to-cost ratios (all contingency used), as well as the greatest calculated benefit-to-cost ratio, providing a view of range of potential outcomes.

Q. WHAT STEPS DID THE COMPANY UNDERTAKE TO VERIFY THAT THE MODEL IS STRUCTURALLY SOUND?

A. The model structure was based on models and similar analyses undertaken by the Company and other utilities in support of similar AMI and grid advancement programs. A number of business areas within the Company, including Regulatory Administration, Risk, Corporate Development, Capital Asset Accounting, Revenue Requirements, Demand Side Management, Business Systems and Distribution, subsequently collaborated to develop and ensure the model incorporated requirements necessary to properly estimate the known and quantifiable life cycle value proposition.

Q. OVERALL, IS THIS CBA AN APPROPRIATE TOOL FOR EVALUATING THE QUANTIFIABLE ASPECTS OF THE AGIS INITIATIVE?

A. Yes. By developing the model from the customer's perspective, the Company is providing clear and comprehensive information about the overall quantifiable impact of implementing these programs to customers. By this we mean that the CBA includes benefits that can be both quantified generally and stated in terms of a reasonably calculable dollar value.

The cost benefit model also provides a high-level look at the costs versus the quantifiable benefits of the overall AGIS initiative for customers, as well as a more detailed breakdown of individual costs and benefits assumptions for each program. However, the cost benefit model does not address all reasons for undertaking the AGIS program or the benefits of the program because many such reasons and benefits cannot be quantified or reduced to a dollar value. Therefore, the cost benefit model provides an appropriate perspective on the quantifiable costs and benefits of the program but not on all relevant considerations.

Q. WHY DO YOU SAY THE MODEL PROVIDES AN APPROPRIATE PERSPECTIVE ON QUANTIFIABLE CONSIDERATIONS?

A. Because a CBA is, by definition, intended to quantify costs and benefit, it can only capture the quantifiable. As discussed later in my testimony, examples of benefits that were not quantified include customer satisfaction, customer choice, planning and control of the grid, greater hosting capacity, job creation, improved quality of service delivered, and safety, among others described by Ms. Bloch, Mr. Cardenas, Mr. Gersack, and myself. This is why the CBA is one tool, but it should not be regarded as a definitive analysis on the merits of AGIS, because it cannot consider factors that are qualitative or on which the Company has not put a price (like human safety).

In addition, a model based on measureable considerations does not take into account any fundamental need for the infrastructure in question. For example, the Company must have meters in order to provide and bill for electric service. We therefore must plan for the pending expiration of the Cellnet AMR service contract while also taking into account that Xcel Energy is the last company using the Cellnet technology embedded in the Company's current meters. However, a cost versus benefit model cannot fully reflect that the primary function of updated meters is not necessarily to reduce the net cost of meters compared to aged technology, but rather to enable the utility to provide services to meet the needs and expectations of the customer.

Finally, while the model can and does reflect the costs of AMI versus AMR technology as an avoided cost alternative, it cannot fully assess whether it would be short-sighted or impracticable for the Company to replace aging technology with other aging technology, nor the effect of using older technology on unquantifiable customer expectations (like better outage and service restoration communications, and more timely energy consumption data) that is more dependent on advanced metering technology. All told, the model is a helpful assessment tool within the scope of its intended purpose. And because the Company has taken a conservative approach to modeling the benefits and costs of the AGIS strategy, we believe it is a reliable and helpful tool.

B. Quantitative Inputs

1. AMI Inputs

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

A. Company witness Ms. Bloch discusses the costs and benefits of AMI in detail in her testimony. At a high level, the benefits of AMI include: (i) providing more granular customer energy usage information that supports greater customer energy usage choice, pricing flexibility, and carbon reduction; (ii) reducing field and meter service and meter reading costs; (iii) reducing unaccounted for energy; (iv) assisting with identification of service outages and foster restoration; (v) providing voltage measurement information to assist in load flow and voltage calculations performed in the ADMS; (vi) serving as signal repeaters for other AMI meters and FAN network components; and (vii) improving infrastructure investment efficiencies. The purchase of AMI meters also enables the Company to retire the end-of-life Cellnet technology that will no longer be supported in the future (as described by Company witness Mr. Cardenas) and avoid the purchase of other, less functional advanced meter reading (AMR) meters in the near future. As discussed below, not all of the benefits of AMI are quantifiable or able to be reduced to a dollar value. In the cost benefit model, however, we have identified and captured the costs and quantifiable benefits associated with the technology.

The key costs of AMI include the meters themselves, including the labor cost of installation and testing, supporting FAN and IT resources, AMI program and management, and other supporting labor for operations.

Q. HOW WERE AMI CAPITAL COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the AMI program were developed by the Company's subject matter experts and are detailed in the Direct Testimonies of Ms. Bloch, Mr. Harkness, Mr. Gersack, and Mr. Cardenas, as set forth in Tables 2 through 6 below. My Exhibit ___ (RD-1), Schedule 2 provides a summary of each component of the quantifiable AMI costs and benefits, as they appear in the CBA.

Table 2

AMI Capital Costs

Capital Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Meters and Installation	Capital costs portion of AMI meter purchase and installation. Capital costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(D)(5)
Field Area Network (AMI)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
	Capital costs associated with installation of pole-mounted devices.	Direct Testimony of Ms. Bloch, Section V(E)(3)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of AMI.	Direct Testimony of Mr. Harkness, Section V(E)(3)(c)
Program and Change Management	Capital costs associated with internal management of AMI.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 3

AMI Capital Benefits

Capital Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved capital spend efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Avoided Meter Purchases for Failed Meters	AMI meters have a lower failure rate as compared to AMR meters. By purchasing new AMI meters, the Company avoids the need to replace failing AMR meters.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Avoided investment of an alternative meter reading system	Avoided capital cost of a drive-by meter reading system, instead of the AMI investment, since current Cellnet system requires replacement	Direct Testimony of Ms. Bloch, Section V(D)(4)

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

A. O&M estimates for the AMI program were likewise developed by the Company's other AGIS witnesses, as set forth in Tables 3,4, and 5 below.

Table 4

AMI O&M Costs

O&M Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Field Area Network (AMI) allocated portion	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of AMI.	Direct Testimony of Mr. Harkness, Section V(E)(3)(c)
AMI Operations (Personnel)	O&M costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(D)(5)
Program Management	O&M costs associated with internal change management and oversight for AMI.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 5

AMI O&M Benefits

O&M Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Avoided O&M Meter Reading Cost	O&M cost component of a drive-by meter reading system alternative to AMI, since current Cellnet system requires replacement	Direct Testimony of Mr. Cardenas, Section V(F)
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Outage Management Efficiency	Improved O&M efficiency during outage events.	Direct Testimony of Ms. Bloch, Section V(D)(4)

Table 6

Other Quantifiable AMI Benefits

Benefit	**Description**	**Supporting Witness (including Section of Testimony)**
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Consumption Inactive Premise	Expedited ability to turn off power quickly when determined premise has been vacated.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible/bad debt.	Direct Testimony of Mr. Cardenas, Section V(F)
Reduced Outage Duration	Direct benefit to customers associated with reduced outage duration.	Direct Testimony of Ms. Bloch, Section V(D)(4)
Critical Peak Pricing	Customer demand savings in response to new rate structures.	Brattle Group Report, Exhibit ___ (RD-1), Schedule 6 and additional detail in this Section of my Direct Testimony
TOU Customer Price Signals	Difference in energy prices paid by consumers in response to new rate structures.	Integrated Resource Plan – RP-19-368 Appendix F2 and additional detail in this Section of my Direct Testimony
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to shifted load.	Additional detail in this Section of my Direct Testimony

Q. CAN YOU SUMMARIZE THE BENEFITS YOU DESCRIBE IN YOUR TESTIMONY?

A. Yes. As noted in Table 6 above, I discuss how the Company calculated AMI benefits associated with critical peak pricing and TOU customer price signals (combined, "load flexibility" benefits), as well as reduced CO_2 emissions. Exhibit ___ (RD-1), Schedule 5 identifies the quantification of these benefits for purposes of the CBA.

Q. CAN YOU PROVIDE MORE INFORMATION REGARDING THE COMPANY'S LOAD FLEXIBILITY ASSUMPTIONS?

A. Yes. The Company engaged The Brattle Group (Brattle) to model likely customer response to Time of Use (TOU) and Critical Peak Pricing (CPP) rates. The Brattle Group produced a study entitled "The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory" (the Brattle Study), which is attached to my Direct Testimony as Exhibit___ (RD-1), Schedule 6. The Brattle Study developed quantification of the benefits of potential TOU and CPP rates, which were in turn incorporated into our CBA.[5] Further, the Company utilized information about shifting demand from on-peak to off-peak periods, resulting in energy price savings for customers and carbon reduction benefits.

Q. WHY DID THE COMPANY RELY ON THE BRATTLE STUDY?

A. Brattle is a well-respected economic consulting and analytics firm, and conducted a similar study for Public Service Company of Colorado (Xcel Energy's Colorado utility operating company), in relation to its portion of the AGIS initiative. As a result, we have experience with this group and have found their studies to be robust and reasonable.

Q. PLEASE DESCRIBE THE TOU ASSESSMENT IN THE BRATTLE STUDY.

A. The Brattle Study assumes a static price signal with higher prices during the five-hour period around system peak on non-holiday weekdays, and models both opt-in and opt-out approaches to time of use rates.[6] Demand reduction

[5] I note that while Brattle modeled CPP rates and we have used this information in our CBA in this case, there are a variety of peak demand rate design structures the Company may explore, such as peak time rebates.

[6] Brattle Study at p.6.

grows modestly as TOU adoption and utilization expands. Based on these assumptions and the base case in the Brattle analysis, this rate has the potential to shift demand approximating 161 Megawatts (MW) for residential customers and 52 MW for medium commercial and industrial customers from on-peak to off-peak.[7] The overall result is cost savings to customers.

Q. WHAT ARE THE BENEFITS ASSOCIATED WITH CRITICAL PEAK PRICING?

A. The potential CPP rate "provides customers with a much higher rate during peak hours on 10 to 15 days per year."[8] CPP rates were modeled by Brattle as being offered on both an opt-in and an opt-out (default) basis, with demand reduction growing modestly as the system and system usage mature. This rate has the potential to reduce peak demand at the generator level by 164 MW for residential customers and 90 MW for medium commercial and industrial customers under the base case scenario.[9]

Q. HOW WERE THESE CHANGES IN THE COMPANY'S CUSTOMER PRICE SIGNALS TRANSLATED TO BENEFITS IN THE AGIS AMI CBA?

A. The Company utilized the peak demand reduction assumptions from the Brattle Study to generate an estimated energy shift from peak to off-peak hours. This shift from peak to off-peak was then multiplied by the difference in the Minnesota Hub on and off-peak price forecasts filed with our Integrated Resource Plan (Docket No. E002/RP-19-368) on page 13 of Appendix F2. This estimates the savings in energy prices customers will experience in shifting their demand from on to off-peak.

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[7] Brattle Study at Appendix D, p.68.
[8] Brattle Study at p.6.
[9] Brattle Study at Appendix D, p. 68.

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT DUE TO REDUCTIONS IN CARBON DIOXIDE EMISSIONS FOR AMI?

A. The Company utilized load shifting estimates in MWh for TOU rates from The Brattle Study. The Company estimated on-peak and off-peak average CO_2 emissions by year using internal tools. The difference in those two estimates represents the emissions improvement. This amount is multiplied by the MWh shifted due to TOU rates. The avoided carbon emission is valued by multiplying the avoided emissions by the Commission-ordered externality values from Docket No. E999/CI-14-643.

Q. HOW DOES THE BRATTLE GROUP'S FRAMEWORK COMPARE TO OTHERS FOR MEASURING LOAD FLEXIBILITY?

A. As noted by Brattle on page ii of the Study, its modelling framework "builds upon the standard approach to quantifying [demand response] potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs." The Brattle Group then goes on to identify those differentiating features, each of which is intended to enhance the reliability and sophistication of the analysis. The Company therefore relied upon the Brattle Study to assume that a consistent reduction in peak demand would be reasonable and achievable as a function of the demand rates AMI will enable as part of the Company's proposal. This reduction is then incorporated into the CBA as a benefit of AMI.

Q. WHAT ASSUMPTIONS ARE MADE WITH RESPECT TO CUSTOMER ADOPTION OF THESE NEW TECHNOLOGIES?

A. As discussed in more detail by Company witness Mr. Cardenas, we propose an opt-out approach to AMI metering, meaning that customers will be automatically integrated into the new system unless they actively opt out. In addition, the opt-out deployment approach tends to result in overall higher enrollment rates than when utilities adopt an opt-in approach to AMI, and therefore enables larger aggregate demand impacts via the more advanced rate structures AMI enables. Overall, the Brattle Study notes that an opt-out approach – with the default being the customer receives AMI functionality – "maximizes the overall economic benefit of the program."[10] The Brattle Group modeled this opt-out approach as the default rate offering.

Q. WHAT IS THE IMPACT OF THESE OPT-OUT ASSUMPTIONS ON THE CBA?

A. There is no direct net cost impact because, as Mr. Cardenas explains, we propose to have those customers who opt out pay for the cost of a new meter capable of storing data needed for future rate designs. In addition, customers who opt out would incur a monthly charge to cover the cost of meter reading. Because these charges would be established in an amount that directly offsets the costs of opting out, there is no direct material net cost impact to the CBA. However, the opt-out approach does improve the benefit as described above.

2. FLISR Inputs

Q. WHAT IS THE FLISR PROGRAM?

A. The Fault Location Isolation and Service Restoration (FLISR) component of the AGIS initiative is a synchronized system of devices that can reduce the

[10] Brattle Study at p. 31.

number of customers impacted by a fault via automatically isolating the trouble area and restoring service to remaining customers by transferring them to adjacent circuits. The fault isolation feature of the technology can help crews locate the trouble spots more quickly, resulting in shorter outage durations for the customers impacted by the faulted section. In short, the purpose of FLISR is to reduce the duration and impact of outages on our customers. Company witness Ms. Bloch discusses the purpose of FLISR in more detail.

Q. WHAT ARE THE COSTS OF FLISR?

A. The majority of the FLISR costs are the asset/device costs, as well as the labor cost of installation. Other costs include the supporting FAN components and IT resources. As previously noted, FLISR costs also include contingency amounts.

Q. HOW WERE FLISR COST AND BENEFIT INPUTS DERIVED FOR PURPOSES OF THE COST BENEFIT MODEL?

A. Capital and O&M cost and benefit estimates for the FLISR program (including contingencies) are detailed in the Direct Testimony of Company witnesses Ms. Bloch and Mr. Harkness, as set forth in Tables 6 through 8 below. FLISR's quantifiable benefits relate primarily to Customer Minutes Out (CMO) measures of reduced customers' outage duration; therefore, the benefits of FLISR are not directly O&M or capital-related. My Exhibit___(RD-1), Schedule 3 provides a summary of each component of the quantifiable FLISR costs and benefits, as they appear in the CBA.

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

A. A summary of capital costs is set forth in Table 7, below.

Table 7

Capital Costs of FLISR

Capital Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	Capital costs of the FLISR devices and installation, including both internal and external support	Direct Testimony of Ms. Bloch, Section V(F)(6)
Field Area Network (FLISR)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of FLISR.	Direct Testimony of Mr. Harkness, Section V(E)(5)(b)

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

A. FLISR O&M costs and benefits were developed by Ms. Bloch and Mr. Harkness as set forth below:

Table 8

FLISR O&M Costs

O&M Cost	**Description**	**Supporting Witness (including Section of Testimony)**
Assets and Installation	O&M costs of the FLISR devices and installation.	Direct Testimony of Ms. Bloch, Section V(F)(6)
Field Area Network (FLISR)	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of FLISR.	Direct Testimony of Mr. Harkness, Section V(E)(5)(b)

Table 9

Other Quantifiable FLISR Benefits

Benefits	**Description**	**Supporting Witness (including Section of Testimony)**
Customer Minutes Outage – Savings	Benefits to customers associated with reduced outage duration	Direct Testimony of Ms. Bloch, Section V(F)(5)
Outage Patrol Time Savings	Benefit associated with reduction in time spent by field crews responding to outages	Direct Testimony of Ms. Bloch, Section V(F)(5)

3. IVVO Inputs

Q. WHAT IS INTEGRATED VOLT-VAR OPTIMIZATION?

A. Generally speaking, IVVO is a leading technology that automates and optimizes the operation of distribution voltage regulating devices and VAr control devices to maximize system efficiency. As described in more detail in the Direct Testimony of Ms. Bloch, through the implementation of IVVO the Company will be able to control the voltage on a distribution feeder to a tighter tolerance, permitting the Company to lower the voltage on that controlled feeder while still maintaining a high level of service quality. This lower voltage will effectuate energy and demand savings for the system and for the customer.

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

A. The primary costs of implementing IVVO relate to installation of application assets as well as the labor cost of installation. Other costs include FAN communications, IT systems and integration, and program management. The benefits of IVVO that were quantified in the CBA are the fuel and energy savings and capacity savings associated with the program, which are described by Ms. Bloch, and the associated carbon reduction that I describe. The costs of IVVO also include contingency amounts, which are supported by Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack.

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

A. Capital and O&M cost estimates for the IVVO program (including contingencies) are detailed in the Direct Testimony of Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack, as set forth in Tables 10 through 13 below. My Exhibit___(RD-1), Schedule 4 provides a summary of each component of the quantifiable IVVO costs and benefits, as they appear in the CBA.

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

A. A summary of capital costs and benefits is set forth in Table 10 and 11, below.

Table 10

IVVO Capital Costs

Capital Cost	Description	Supporting Witness (including Section of Testimony)
Assets and Installation	Capital costs of the IVVO devices and installation. Capital costs of both internal and external support personnel.	Direct Testimony of Ms. Bloch, Section V(G)(5)
Field Area Network (IVVO)	Capital costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of IVVO.	Direct Testimony of Mr. Harkness, Section V(E)(6)(b)
Program Management	Capital costs associated with internal management of IVVO.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 11

IVVO Capital Benefits

Capital Benefits	Description	Supporting Witness (including Section of Testimony)
Avoided Capacity Costs	Avoided generation, transmission and distribution capacity achieved through demand reduction	Direct Testimony Ms. Bloch, Section V(G)(4)

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

A. IVVO O&M costs and Other benefits were developed as set forth below:

Table 12

IVVO O&M Costs

O&M Cost	Description	Supporting Witness (including Section of Testimony)
Assets and Installation	O&M costs of the IVVO devices and installation.	Direct Testimony of Ms. Bloch, Section V(G)(5)
Field Area Network (IVVO)	O&M costs associated with implementation of the WiSUN network and associated assets.	Direct Testimony of Mr. Harkness, Section V(E)(4)(e)
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of IVVO.	Direct Testimony of Mr. Harkness, Section V(E)(6)(b)
Program Management	O&M costs associated with internal management of IVVO.	Direct Testimony of Mr. Gersack, Section V(D)(2)

Table 13

Other Quantifiable IVVO Benefits

Other Benefits	Description	Supporting Witness (including Section of Testimony)
Fuel Savings (Energy Reduction)	Fuel cost savings associated with avoided energy usage	Direct Testimony of Ms. Bloch, Section V(G)(4)
Fuel Savings (Energy Reduction)	Fuel cost savings associated with reduction in line losses	Direct Testimony of Ms. Bloch, Section V(G)(4)
Reduced Carbon Dioxide Emissions	Difference in emissions of generation assets due to load reduction.	My Direct Testimony, below

Q. HOW DID THE COMPANY QUANTIFY THE BENEFIT DUE TO REDUCTIONS IN CARBON DIOXIDE EMISSIONS FOR IVVO?

A. As described by Company witness Ms. Bloch, the Company estimated the energy savings associated with the IVVO program. This reduction in energy usage was converted to avoided CO_2 emissions based on projected CO_2 intensity per MWh. We then calculated the societal benefit of these avoided CO_2 emissions using the Commission-ordered externality values from its

January 3, 2018, Order Updating Environmental Cost Values in Docket No. E999/CI-14-643.

Q. ARE THERE ANY UNIQUE ASPECTS OF IVVO FOR CBA PURPOSES, AS COMPARED TO THE OTHER COMPONENTS OF AGIS?

A. Yes. As Ms. Bloch describes in more detail, IVVO benefits depend on assumptions about the level of energy and demand savings that can be achieved on NSPM's specific system. She explains that while the Company feels confident that 1 percent average energy savings and 0.6 percent capacity savings are the most readily achievable levels, the Company also identified 1.5 percent energy savings and 0.8 percent capacity savings as the higher end of the achievable range. For purposes of the CBA, we utilized the mid-point of the range (1.25 percent energy savings and 0.7 percent capacity savings), and also present as sensitivities that utilize the lower (1.0 percent energy/0.6 percent capacity savings) and upper (1.5 energy/0.8 percent capacity savings) ends of the identified range. Below I provide the resulting benefit-to-cost ratios with and without contingency.

Q. OVERALL, HOW WOULD YOU CHARACTERIZE THE COST AND BENEFIT BUDGETING ASSUMPTIONS IN THIS MODEL FOR EACH OF THE COMPONENTS OF THE AGIS INITIATIVE?

A. Particularly for the modeling results that include 100 percent of the Company's planned contingencies, I would characterize this model as a conservative representation of estimated costs and benefits. Because AMI, FLISR, and IVVO are still in their early phases, the contingencies represent early estimates of potential additional costs. Likewise, the Company has estimated customer adoption and response on the basis of the Brattle Study;

as technologies continue to improve, the benefits associated with these technologies may also increase. Our goal is to represent a conservative but realistic analysis to support the Commission's review of our cost benefit model for the AGIS initiative.

C. CBA Results

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

A. Table 14 summarizes the results of the Company's evaluation of AMI, both with and without contingency.

Table 14
AMI Benefit-to-Cost Ratio

NSPM-AMI-NPV	**Total ($MM)**
Benefits	446
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	(538)
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**
Benefit/Cost Ratio (no contingencies)	**0.99**

Exhibit___(RD-1), Schedule 3 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of AMI, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF AMI?

A. On a total resource benefit-to-cost ratio basis, AMI is expected to have a benefit-to-cost ratio of approximately 0.83-0.99, which indicates that the costs somewhat exceed quantitative benefits over the analysis period.

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

A. Table 15 summarizes the results of the Company's evaluation of FLISR:

Table 15

FLISR Benefit-to-Cost Ratio

NSPM FLISR- NPV	**Total ($MM)**
Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**
Benefit/Cost Ratio (no contingencies)	**1.53**

Exhibit___(RD-1), Schedule 3 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of FLISR, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF THE FLISR PROGRAM, INCLUDING THE FAN COMPONENT?

A. On a total resource benefit-to-cost ratio basis, FLISR benefits are expected to exceed FLISR cost, with an expected benefit-to-cost ratio of approximately 1.31 to 1.53.

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

A. Table 16 summarizes the results of the Company's evaluation of IVVO, showing sensitivities for contingency ranges and levels of capital/O&M savings assumptions.

Table 16

IVVO Benefit to Cost Ratio

<u>NSPM IVVO- NPV</u>	**Total ($MM)**
Benefits	**22**
Other Benefits	19
CAP Benefits	3
Costs	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (CVR 1.25% energy; 0.7% capacity)	**0.57**
Benefit/Cost Ratio (no contingencies)	**0.61**
Low Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1% energy; 0.6% capacity)	0.46
Benefit/Cost Ratio (no contingencies)	0.49
High Benefit Sensitivity:	
Benefit/Cost Ratio (CVR 1.5% energy; 0.8% capacity)	0.67
Benefit/Cost Ratio (no contingencies)	0.72

Exhibit___(RD-1), Schedule 4 to my Direct Testimony provides more detail regarding the results of the Company's analysis of the costs and benefits of IVVO, including FAN components.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL COSTS AND BENEFITS OF THE IVVO PROGRAM, INCLUDING THE FAN COMPONENT?

A. On a total resource benefit-to-cost ratio basis, IVVO costs are expected to exceed quantifiable IVVO benefits, with an expected benefit-to-cost ratio of 0.57 to 0.61, within a range of sensitivities between 0.46 to 0.72.

Q. DO YOU ALSO PROVIDE A COMBINED SUMMARY OF THE COSTS AND QUANTITATIVE BENEFITS OF THE PROGRAMS?

A. Yes. To determine the combined cost benefit ratio for the AGIS initiative, we identified and aggregated the benefits of each project into four different categories: O&M, Capital, Customer, and Other benefits. At the same time, we aggregated the two types of costs of each project: O&M and Capital/ Change in Revenue Requirements. The final combined ratio is the result of dividing the aggregated benefits by the aggregated costs. Table 17 summarizes the results of the Company's evaluation of the combined AMI/FLISR/IVVO program:

Table 17

AGIS Initiative Combined Cost Benefit Ratio

NSPM -AMI, FLISR, IVVO-NPV	**Total ($MM)**
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
Capital Benefits	193
Costs	**(656)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Baseline Benefit-Cost Ratio (IVVO 1.25% energy, 0.7% capacity, with contingencies)	**0.87**
High Benefit/No Contingency Sensitivity (IVVO 1.5% energy/0.8% capacity, no contingency)	1.03
Lower Benefit/With Contingency Sensitivity (IVVO 1.0% energy/0.6% capacity, with contingencies)	0.86

Exhibit___(RD-1), Schedule 7 to my Direct Testimony provides the overall relative costs and benefits of the AGIS initiative.

Q. WHAT DO YOU CONCLUDE REGARDING THE OVERALL QUANTITATIVE OUTCOMES OF THE AGIS CBA?

A. On a combined basis, the quantifiable benefits of AMI, FLISR, and IVVO are expected to be lower than or in line with program costs, with an expected benefit-to-cost ratio of approximately 0.86 under our low scenario and up to 1.03 with our high sensitivity IVVO benefits and no contingencies. These totals represent a simple combination of AMI, FLISR, and IVVO respective costs and benefits, inclusive of the costs attributable to that portion of the FAN needed to enable AMI, FLISR, and IVVO, presented on a NPV basis.

In the next section of my Direct Testimony, I address other cost/benefit considerations that factor into the overall prudence of the Company's proposed AGIS initiative.

III. LEAST-COST/BEST-FIT ALTERNATIVES

Q. DID THE COMPANY ALSO DEVELOP ANY LEAST-COST/BEST-FIT ANALYSES TO COMPARE METERING ALTERNATIVES?

A. Yes. While Company witness Ms. Bloch also provides extensive discussion regarding the relative costs and benefits of various meter-reading alternatives, my Table 18 summarizes the results of the Company's evaluation. The aggregated benefits and capabilities provided by the AMI system related to its costs definitely surpasses other options, considering the increasing needs and choices demanded by the customers and the upcoming operational distribution-grid challenges. This assessment essentially summarizes the bases for our selection of the AMI solution we are presenting in this case.

Table 18

Meter Reading Least-Cost Best-Fit Alternative

Item	Description	Manual	AMR 1 way/ Limited 2 way	AMR Drive-By	AMI
		Alternative			
Meter Capabilities	Time of use data	◔	◑	◔	●
	Real time notification of power outages	○	◑	○	●
	Fast response to customers inquires	○	◔	○	●
	Support integrated systems that offer customers	○	◔	○	●
	Vehicle to grid interconnects	○	○	○	●
	Remote reconfiguration/ firmware updates	○	○	○	●
	Availability of real time data	○	○	○	●
	Availability of power quality events	○	○	○	●
	Remove availability of meter diagnostic data	◔	◔	◔	●
	Remote disconnect/ connect	○	○	○	●
	Detect unsafe field metering conditions	○	○	○	●
	Energy Theft	◔	◔	◔	●
	Support for advanced rates	○	○	○	●
	Support for ADMS	○	○	○	●
Operational Features	Time consuming activity	A	NA	NA	NA
	Labor intensive - Safety Concerns	A	NA	PA	NA
	Cost of paying someone to read the meters.	A	NA	PA	NA
	Need access to meters to read them.	A	NA	NA	NA
	Accuracy of the meter read, human error.	A	NA	NA	NA
	Usually carried out infrequently (monthly).	A	PA	PA	NA
	Doesn't usually match invoice billing period.	A	PA	PA	NA
	Cost of system maintenance	NA	A	A	A
	Relying on technology	NA	A	A	A
NPV (2019)	Calculated COSTS - CAP Change in RR and O&M			$223M	$539M
	BENEFITS-Incremental to current reading/ billing			$0M	$442M
	NET COST-OUTCOME			**$223M**	**$97M AMI System**
Least-Cost, Best-Fit Alternative Selected					

Legend for Capabilities

Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

Legend for Operational Features

Applicable	Partially Applicable	Non-Applicable
A	PA	NA

Q. HOW DID YOU CALCULATE THE COSTS AND BENEFITS OF THE AMR AND AMI SOLUTIONS FOR PURPOSES OF THIS LEAST-COST/BEST-FIT ANALYSIS?

A. The AMR Drive-by cost and benefit assessments were provided by Company witness Ms. Bloch, and are discussed in her Direct Testimony. The total cost of this system results from the incremental capital and O&M necessary to implement an AMR drive-by solution as a replacement for our current meters. However, this system does not provide any incremental benefit to the current Cellnet meter/billing structure. The costs and benefits of the AMI system were provided by Ms. Bloch, Mr. Harkness, and Mr. Cardenas, as described earlier in my testimony. In contrast, we did not calculate the cost of manual or AMR limited two-way alternatives because we did not consider these realistic solutions given the state of the industry and the needs of our system, customers, and other stakeholders. Table 18 above underscores why we are proposing an AMI solution.

Q. DID YOU COMPLETE A SIMILAR ASSESSMENT WITH RESPECT TO THE COMMUNICATIONS NETWORK NECESSARY TO SUPPORT THE AGIS INITIATIVE?

A. Yes. Company witness Mr. Harkness provides an extensive discussion relative to the costs and benefits of the three communication network alternatives the Company considered. My Table 19 summarizes the results of the Company's evaluation of the aggregated capabilities and protections provided by the FAN with a mesh network, compared to other alternatives.

Table 19

Communications Least-Cost Best-Fit Alternative

Item	Feature/ Requirement	Alternative: Cellular	Alternative: Dedicated AMI	Alternative: FAN Mesh
Network Capabilities	Two way communications	●	●	●
	Peer-to-Peer	◔	◕	●
	Multipurpose	◕	◔	●
	Latency Requirements	●	◕	●
	Security	◑	●	●
	Dedicated traffic	◔	◕	●
	Priority traffic	◔	●	●
	O&M Costs Impact (run state)	◔	◑	●
	Resiliency	◑	◑	●
Operational Features	Cost of paying a third party for service	A	NA	NA
	Unable to fully control the system "end-start"	A	NA	NA
	Unable to implement to some AGIS processes	NA	PA	NA
	Relying on technology	A	A	A
NPV (2019)	Calculated COSTS - CAP Change in RR and O&M			$102M
	BENEFITS-Incremental to current reading/ billing			$0M
	NET COST-OUTCOME			**$102M**
Least-Cost, Best-Fit Alternative Selected				**FAN Mesh**

Legend for Capabilities

Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

Legend for Operational Features

Applicable	Partially Applicable	Non-Applicable
A	PA	NA

Q. HOW DID YOU CALCULATE THE COSTS OF THE COMMUNICATION NETWORK ALTERNATIVES IN THE LEAST-COST/BEST-FIT ANALYSIS?

A. The cost of the FAN components and deployment were provided by Company witness Mr. Harkness, and are described in his testimony. Additionally, Mr. Harkness explains that in comparing alternatives to the FAN, the Company determined that a cellular option would likely have a similar device cost with additional O&M costs; therefore, the cost is expected to be at best equal to and more likely higher than FAN costs. Furthermore, Mr. Harkness explains that a dedicated AMI network was ruled out because it would not allow non-AMI devices to connect to each other or to back office applications, affecting overall system functionality. As such, Table 19 does not show specific cost vs. benefit estimates for alternatives to the FAN, but rather focuses on the relative capabilities of all three alternatives.

Q. DID THE COMPANY COMPLETE A LEAST-COST/BEST-FIT ANALYSIS FOR IVVO OR FLISR?

A. No; it would not have made sense for these components of the AGIS initiative. IVVO and FLISR are, more simply, additional ADMS capabilities. In contrast, there are different fundamental types of meter solutions and communication networks. While there are forms of IVVO and FLISR devices that have different individual capabilities, such comparisons were conducted in the RFP processes, as discussed by Ms. Bloch.

Q. WHAT DO THESE LEAST-COST/BEST-FIT ANALYSES SHOW?

A. They provide another means (in addition to the CBA and the extensive narrative testimony) of comparing the AGIS solutions with alternatives. They largely summarize the analyses Ms. Bloch, and Mr. Harkness provide in much greater detail, and underscore why it was prudent to select AMI and the FAN.

IV. QUALITATIVE BENEFITS OF AGIS

Q. ARE THERE SPECIFICALLY IDENTIFIABLE BENEFITS THE AMI PROGRAM WILL PROVIDE TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. There are a number of benefits of AMI that cannot be quantified either in whole or in part. For example, it is difficult to quantify customers' need and broad expectation to have more choice in and control over their energy usage, or their frustration with older technologies that cannot be updated without better data access. Our analysis captures estimates of customer adoption of technologies to support customer choice and the impacts on energy usage, but cannot fully quantify customer satisfaction associated with having better energy usage and pricing information. Nor can it fully quantify the convenience to customers of better outage management.

The unquantifiable benefits, or benefit the Company did not model in the CBA, are largely discussed by Company witnesses Ms. Bloch, Mr. Harkness, and Mr. Gersack. These include but are not limited to:

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

Q. ARE THERE ANY BENEFITS THAT THE FLISR PROGRAM PROVIDES TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. As with AMI, there are benefits of FLISR that the Company did not attempt to quantify. It is important to note that FLISR does not avoid outages altogether, but works to minimize their impacts on customers when they do occur, improving the customer's experience and leading to customer satisfaction. Thus the qualitative benefits include but are not limited to:

- Improved public and employee safety,
- Value of the data provided by FLISR for system planning purposes, and
- Overall customer satisfaction with utility service.

Q. ARE THERE ANY BENEFITS THAT THE IVVO PROGRAM PROVIDES TO CUSTOMERS OR THE DISTRIBUTION SYSTEM THAT WERE NOT MODELED IN YOUR ANALYSIS?

A. Yes. As with AMI and FLISR, there are benefits of IVVO that the Company did not attempt to quantify. They include but are not limited to:

- Customer bill savings specific to customers whose feeders are equipped with IVVO assets;
- Enhanced automatic access of low income customers to energy efficiency savings;
- Greater efficiencies from the customers' personal electrical devices; and
- Increased hosting capacity of distributed energy resources.

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

A. Yes. With respect to low income customers' access to energy efficiency savings, I note that Ms. Bloch explains how IVVO can reduce voltage, and therefore save customers money without requiring any change in energy usage or activities on the customers' part. Additionally, IVVO is not tied to any particular energy efficiency program, so it has the added benefit of saving money for customers – including low income customers – who are sometimes unable to take advantage of such programs.

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

A. Although the Company feels strongly that these benefits are meaningful to our customers, it is difficult and often highly subjective to attempt to place a dollar value on them. For example, customer satisfaction and empowerment are important to the Company's business model and role as a public utility, but do not easily lend themselves to monetization.

The Company therefore concluded that it was best to provide a cost and benefit analysis to the Commission that fairly represents the cost and benefits of quantifiable projects components, and which we were able to value with reasonable confidence, and then ask the Commission to weigh the other impacts to our customers as it sees fit. In this way, the Commission may rely on the CBA as a baseline of our business case for our projects, and then evaluate and discuss the merits of the additional beneficial impacts to our customers.

Q. WHY SHOULD THE COMMISSION CONSIDER APPROVING COST RECOVERY FOR AMI, FLISR, AND IVVO IF COMBINED PROGRAM COSTS EXCEED THE OVERALL QUANTITATIVE BENEFITS?

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

First, the Company AMI, FLISR, and IVVO implementation will allow the Company to achieve greater visibility into its distribution system, greater opportunities for demand side management, and improved reliability. Conversely, we cannot make the same progress in these areas without enhancing the distribution grid. As Mr. Gersack discusses, these are also necessary components of any new rate structures or other initiatives the Commission may wish to implement; right now, the Company simply does not have the technical capability or insight into customer usage to implement such technologies or customer support without AMI, FLISR, and IVVO.

Second, I would not necessarily expect quantifiable benefits to exceed costs, particularly for AMI, because it is necessary to replace aging technology. On the one hand, the Company's current meters will no longer be considered current technology nor supported as the Cellnet contract comes to an end, but on the other hand a CBA does not take into account that we cannot function without metering. Further, the model cannot fully reflect that AMR meters are an outdated option that will not provide the functionality customers, stakeholders, and the Commission have come to expect, nor the system support necessary in the age of DER.

Third, this model is not the only manner in which we measure the value of the grid advancement options available to us. Much of the Company's comparison of alternative options is completed in the Request for Information (RFI) and Request for Proposal (RFP) proceedings, rather than in a CBA based on our final selections. As described by Ms. Bloch, we have made careful and prudent AMI selections and negotiated a strong contract with our new AMI vendor. Ms. Bloch also discusses alternative considerations and vendor options for other system devices. Likewise, the FAN communications network is the product of robust RFP processes discussed by Mr. Harkness.

Given this prudent approach to selection of infrastructure, the ultimate question is whether overall costs are reasonable.

Fourth, this model can only quantify that which is quantifiable. Its expression of benefits does not include such qualitative benefits as customer choice and convenience, human safety, and potential support for future distributed energy resources. We recognize that choice, convenience, and greater control over energy costs and usage are of increasing importance to our customers. Customer satisfaction and customer empowerment with respect to their energy choices are of central importance to the public utility model.

Fifth and finally, the Company's AGIS witnesses describe at length why it is important to advance the NSPM grid to continue providing safe, increasingly reliable electric service to our customers not just in the present but also into the future. While we cannot predict every new technology that will arrive, we know that our current system is not future-proofed. Conversely, the AGIS program will support a fundamental utility function while improving existing infrastructure that is no longer maximizing service to our customers. It makes future applications, optionality, and distributed energy resources available in a way it is not possible to fully measure because it is not possible to fully predict the future. But as Mr. Gersack describes, utilities nationwide are making these important grid investments because "doing nothing" is not a realistic option. Therefore, the Company feels that this is both the right time and an important time to modernize critical components of its distribution grid.

V. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. The Company's AGIS CBA is a tool that is helpful, but not sufficient, to assess the overall prudence of the AGIS strategy and investments. We believe it is realistic and appropriate that our CBA shows individual and composite benefit-to-cost ratios that approach 1.0 (or exceed 1.0 in the case of FLISR), even before taking into account unquantifiable benefits. With those qualitative considerations and benefits, the Company believes the value of the AGIS initiative and its respective components substantially exceed the costs. Finally, both the CBA itself and our least cost/best fit summative analyses underscore that our AGIS program is reasonable given the need to replace aging technology, bring our distribution grid into the future, meet customer needs and offer greater customer choice, and take advantage of opportunities to use technology to support demand side management, peak demand reductions, and build a more resilient and responsive grid.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

Statement of Qualifications

Ravikrishna Duggirala
Director, Risk Strategy
1800 Larimer Street, Denver, Colorado

Ravikrishna Duggirala has more than 25 years of diverse experience in various industries in the areas of Engineering, Operations, Business Development, and Risk Management. Dr. Duggirala joined Xcel Energy in 2002 and is currently Director of Risk Strategy, where he is responsible for Enterprise Risk Management, Asset Risk Management, risk analytics, and modeling. He has held this position since 2008. Previously, Dr. Duggirala was the Manager of Energy Sales Risk for Xcel Energy from 2005 through 2008, where he was responsible for retail sales risk analysis, key risk analysis, sensitivity analysis, and risk analytics. Dr. Duggirala was also a Risk Consultant with the Company between 2002 and 2005, where he was responsible for monitoring and reporting of trading risks, managing risk policies and procedures and supporting Corporate Risk Management Oversight Committee. Prior to working for Xcel Energy, Dr. Duggirala worked at other companies including Enron, Monsanto, and Purdue University in various capacities.

Dr. Duggirala received his Masters Degree in Business Administration from Washington University in St. Louis in 2000, and his Ph.D in Engineering from Purdue University in 1996.

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Deployed	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
CAPITAL COSTS																		***TOTAL DISCOUNTED***	***NSPM-NPV***
AMI Meters																			
AMI Meters Purchase	1,408,513	1,024,373	13,875,456	71,769,600	67,212,800	4,636,544	1,771,935	1,826,384	1,882,506	1,940,352	1,999,976	2,061,432	2,124,776	2,190,067	2,257,364	2,326,730	2,398,226	**182,707,036**	**132,855,955**
AMI Meter Installation	620,017	450,922	5,054,700	26,145,000	24,485,000	1,689,050	645,500	665,335	685,779	706,852	728,573	750,961	774,036	797,821	822,337	847,606	873,652	**66,743,140**	**48,567,278**
RTU's (Return to Utility- Estimate 3% of installed meters)	0	0	303,282	1,568,700	1,469,100	101,343	0	0	0	0	0	0	0	0	0	0	0	**3,442,425**	**2,619,423**
Vendors deployment Project Management	0	381,182	733,817	1,198,410	1,223,217	624,270	0	0	0	0	0	0	0	0	0	0	0	**4,160,897**	**3,204,164**
AMI Operations (Internal Personnel)	843,677	983,487	1,869,203	2,046,398	2,186,980	1,903,327	0	0	0	0	0	0	0	0	0	0	0	**9,833,071**	**7,716,691**
AMI Operations (External Personnel)	0	0	658,073	1,372,663	1,365,055	637,919	0	0	0	0	0	0	0	0	0	0	0	**4,033,710**	**3,053,879**
Shop & Lab equipment (AMI Field Test, Lab equip)	0	25,888	217,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**243,288**	**203,171**
Distribution Contingencies	442,320	441,341	3,497,637	16,031,519	15,083,091	1,477,238	0	0	0	0	0	0	0	0	0	0	0	**36,973,146**	**28,259,602**
TOTAL - AMI Meters	3,314,527	3,307,193	26,209,569	120,132,290	113,025,244	11,069,690	2,417,435	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	***308,136,713***	***226,480,162***
Communications Network																			
FAN Infrastructure Distribution	100,005	650,501	1,279,994	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,030,499**	**1,729,867**
FAN Distribution WiMax	322,537	2,097,993	4,128,233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,548,763**	**5,579,166**
FAN Bus Sys Costs	1,709	51,120	88,387	59,329	56,142	15,200	0	0	0	0	0	0	0	0	0	0	0	**271,887**	**217,842**
FAN Bus Sys WiMAX Cost	334,633	10,011,076	17,309,267	11,618,600	10,994,506	2,976,466	0	0	0	0	0	0	0	0	0	0	0	**53,244,549**	**42,660,847**
FAN Bus Sys Contingency	73,854	1,267,037	2,253,221	1,166,606	1,103,942	298,863	0	0	0	0	0	0	0	0	0	0	0	**6,163,522**	**4,979,818**
TOTAL - Communications	*832,739*	*14,077,726*	*25,059,102*	*12,844,535*	*12,154,590*	*3,290,528*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***68,259,221***	***55,167,540***
IT Systems and Integration																			
IT Hardware	1,504,080	2,537,978	2,141,049	545,521	556,814	568,340	580,104	0	0	0	0	0	0	0	0	0	0	**8,433,885**	**7,028,256**
IT Software	1,064,115	1,552,117	5,536,877	4,669,670	323,141	0	0	0	0	0	0	0	0	0	0	0	0	**13,145,919**	**10,838,063**
IT Labor + Project Management	1,725,374	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,725,374**	**1,621,097**
IT Contingency	0	0	0	11,176,589	605,252	548,564	174,031	0	0	0	0	0	0	0	0	0	0	**12,504,436**	**9,642,915**
TOTAL - IT Systems and Integration	*4,293,568*	*4,090,095*	*7,677,926*	*16,391,780*	*1,485,207*	*1,116,904*	*754,136*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***35,809,615***	***29,130,330***
Program Management																			
Change Management	0	1,000,000	1,035,500	1,072,260	1,110,325	1,149,742	1,190,558	0	0	0	0	0	0	0	0	0	0	**6,558,386**	**4,950,734**
Environment/Release Management	0	28,071	2,064,464	2,318,348	1,044,303	355,017	99,666	0	0	0	0	0	0	0	0	0	0	**5,909,870**	**4,617,070**
Finance	0	109,959	193,798	194,658	145,467	0	0	0	0	0	0	0	0	0	0	0	0	**643,882**	**516,017**
PMO	0	288,790	506,590	508,944	381,346	0	0	0	0	0	0	0	0	0	0	0	0	**1,685,670**	**1,350,955**
Security	0	1,105,737	1,144,991	1,185,638	1,227,728	0	0	0	0	0	0	0	0	0	0	0	0	**4,664,093**	**3,748,708**
Supply Chain	0	477,703	487,591	497,685	507,987	0	0	0	0	0	0	0	0	0	0	0	0	**1,970,966**	**1,585,917**
Talent Strategy	238,852	349,325	361,726	185,901	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,135,803**	**977,689**
Delivery and Execution Leadership	0	374,158	1,294,786	1,314,010	667,319	0	0	0	0	0	0	0	0	0	0	0	0	**3,650,273**	**2,916,840**
Contingency	11,943	186,687	354,472	363,872	254,224	75,238	64,511	0	0	0	0	0	0	0	0	0	0	**1,310,947**	**1,033,197**
TOTAL - Program Management	*250,795*	*3,920,430*	*7,443,919*	*7,641,315*	*5,338,699*	*1,579,997*	*1,354,735*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***27,529,891***	***21,697,127***
TOTAL CAPITAL	8,691,629	25,395,444	66,390,515	157,009,920	132,003,740	17,057,120	4,526,306	2,491,719	2,568,285	2,647,205	2,728,549	2,812,393	2,898,813	2,987,889	3,079,701	3,174,336	3,271,878	*439,735,439*	*332,475,159*
O&M ITEMS																			
Communications Network																			
FAN Network Infrastructure Distribution	0	0	130,976	298,507	271,352	225,136	105,810	54,000	55,118	56,259	57,424	58,612	59,826	61,064	62,328	63,618	64,935	**1,624,966**	**1,036,835**
FAN Network Business Systems	0	0	335,766	3,171,422	2,673,589	1,491,278	499,575	671,918	685,827	700,023	714,514	729,304	744,401	759,810	775,538	791,592	807,978	**15,552,536**	**9,460,970**
FAN WiMAX Cost	233,600	357,245	427,150	434,290	562,241	1,048,049	653,607	0	0	0	0	0	0	0	0	0	0	**3,716,182**	**2,782,723**
NOC Opco Allocation	200,000	408,280	625,097	638,037	651,244	664,725	678,485	692,529	706,864	721,497	736,432	751,676	767,235	783,117	799,328	815,874	832,762	**11,473,181**	**6,445,717**
FAN Network Distribution Contingency	0	0	59,854	136,414	124,004	102,885	48,354	24,677	0	0	0	0	0	0	0	0	0	**496,189**	**363,768**
FAN Network Bus Sys Contingency	0	0	301,130	686,305	623,871	517,616	243,271	124,153	0	0	0	0	0	0	0	0	0	**2,496,348**	**1,830,131**
TOTAL - Communications	*433,600*	*765,525*	*1,879,974*	*5,364,975*	*4,906,301*	*4,049,690*	*2,229,101*	*1,567,278*	*1,447,809*	*1,477,779*	*1,508,369*	*1,539,592*	*1,571,462*	*1,603,991*	*1,637,194*	*1,671,084*	*1,705,675*	***35,359,401***	***21,920,143***
IT Systems and Integration																			
IT Hardware	42,114	1,654,282	1,678,585	1,705,324	1,740,624	1,776,655	1,813,432	1,850,970	1,889,285	1,928,393	1,968,311	2,009,055	2,050,642	2,093,091	2,136,418	2,180,642	2,225,781	**30,743,604**	**17,268,781**
IT Software	27,285	85,988	983,487	1,845,314	2,011,390	2,053,026	2,095,523	2,138,900	2,183,176	2,228,367	2,274,495	2,321,577	2,369,633	2,418,685	2,468,752	2,519,855	2,572,016	**32,597,467**	**17,432,600**
IT Labor	0	2,056,405	1,553,273	1,750,246	1,680,090	1,717,226	1,721,011	1,789,073	1,859,799	1,933,290	2,009,656	2,089,007	2,171,461	2,257,136	2,346,156	2,438,653	2,534,759	**31,907,241**	**17,784,018**
Common Corporate Business System development-Allocation	646,904	4,270,861	5,304,505	11,866,886	12,378,199	10,847,247	10,347,121	0	0	0	0	0	0	0	0	0	0	**55,661,724**	**41,239,207**
IT Contingency	0	997,287	9,826,939	4,112,864	2,099,639	2,145,629	2,192,624	2,240,646	2,289,716	2,339,857	2,391,093	2,443,448	2,496,946	2,551,611	2,607,470	2,664,547	2,722,871	**46,123,186**	**28,075,602**
TOTAL - IT Systems and Integration	*716,303*	*9,064,823*	*19,346,789*	*21,280,633*	*19,909,942*	*18,539,783*	*18,169,711*	*8,019,589*	*8,221,975*	*8,429,907*	*8,643,555*	*8,863,087*	*9,088,683*	*9,320,523*	*9,558,795*	*9,803,697*	*10,055,427*	***197,033,221***	***121,800,207***
Program Management																			
Change Management	0	1,825,114	2,157,971	3,067,323	3,176,213	2,991,329	1,608,666	0	0	0	0	0	0	0	0	0	0	**14,826,616**	**11,214,681**
Environment/Release Management	0	0	22,405	23,200	24,024	24,877	11,794	0	0	0	0	0	0	0	0	0	0	**106,300**	**78,991**
Finance	0	32,456	112,027	167,045	216,218	0	0	0	0	0	0	0	0	0	0	0	0	**527,746**	**410,061**
PMO	0	79,772	275,346	410,574	531,437	0	0	0	0	0	0	0	0	0	0	0	0	**1,297,129**	**1,007,876**
Talent Strategy	37,760	58,651	60,733	0	55,000	0	0	0	0	0	0	0	0	0	0	0	0	**212,144**	**177,898**
Delivery and Execution Leadership	0	217,284	510,624	714,661	897,539	0	0	0	0	0	0	0	0	0	0	0	0	**2,340,109**	**1,829,448**
Contingency	1,888	110,664	156,955	219,140	245,022	150,810	81,023	0	0	0	0	0	0	0	0	0	0	**965,502**	**735,948**
TOTAL - Program Management	*39,648*	*2,323,940*	*3,296,060*	*4,601,944*	*5,145,453*	*3,167,016*	*1,701,483*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	***20,275,545***	***15,454,901***
AMI Operations (Personnel)																			
AMI Operations (Internal Personnel)	0	2,029	36,563	40,759	42,206	43,704	47,708	1,040,317	1,077,248	1,115,491	1,155,090	1,196,096	1,238,558	1,282,526	1,328,056	1,375,202	1,424,022	**12,445,575**	**5,756,644**
AMI Operations (External Personnel)	0	187,968	214,121	468,050	1,576,002	1,300,659	1,409,575	1,475,931	1,545,439	1,600,302	1,657,112	1,715,940	1,776,856	1,839,934	1,905,252	1,972,888	2,042,926	**22,688,954**	**11,693,307**
Customer Claims	0	663	1,719	48,916	48,843	7,423	0	0	0	0	0	0	0	0	0	0	0	**107,565**	**81,001**
Total AMI- O&M Dist Contingency	0	29,259	38,605	78,357	249,204	207,032	224,422	387,502	403,894	418,232	433,079	448,454	464,374	480,859	497,929	515,606	533,910	**5,410,717**	**2,687,292**
TOTAL - AMI Operations	*0*	*219,920*	*291,008*	*636,082*	*1,916,255*	*1,558,818*	*1,681,704*	*2,903,750*	*3,026,581*	*3,134,024*	*3,245,282*	*3,360,490*	*3,479,787*	*3,603,319*	*3,731,237*	*3,863,696*	*4,000,857*	***40,652,811***	***20,218,244***
TOTAL O&M	1,189,551	12,374,208	24,813,831	31,883,634	31,877,951	27,315,307	23,782,000	12,490,618	12,696,365	13,041,711	13,397,206	13,763,169	14,139,931	14,527,833	14,927,226	15,338,477	15,761,959	293,320,977	179,393,496
GRAND TOTAL CAPITAL & O&M	9,881,180	37,769,652	91,204,347	188,893,554	163,881,691	44,372,427	28,308,306	14,982,337	15,264,650	15,688,915	16,125,755	16,575,562	17,038,744	17,515,722	18,006,927	18,512,812	19,033,837	733,056,417	511,868,655

XCEL ENERGY

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
O&M ITEMS																			
Avoided O&M Meter Reading Costs																			
Drive-by Meter Reading Cost - O&M	2,155	86,393	1,085,789	2,460,063	3,740,671	3,587,859	4,153,792	4,287,938	4,426,475	4,562,493	4,702,691	4,847,197	4,996,143	5,149,667	5,307,907	5,471,011	5,639,126	**64,507,370**	**33,455,306**
TOTAL - Reduction in Meter Reading Costs	*2,155*	*86,393*	*1,085,789*	*2,460,063*	*3,740,671*	*3,587,859*	*4,153,792*	*4,287,938*	*4,426,475*	*4,562,493*	*4,702,691*	*4,847,197*	*4,996,143*	*5,149,667*	*5,307,907*	*5,471,011*	*5,639,126*	*64,507,370*	*33,455,306*
Reduction in Field and Meter Services																			
Costs savings from remote disconnect capability	0	0	0	0	386,423	1,108,454	1,592,346	1,814,095	1,878,495	2,060,451	2,133,597	2,209,340	2,287,771	2,368,987	2,453,086	2,540,171	2,630,347	**25,463,562**	**12,291,603**
Reduction in trips due to Customer equipment damage	0	0	0	0	32,617	67,549	139,894	144,860	150,003	155,328	160,842	166,552	172,465	178,587	184,927	191,492	198,290	**1,943,406**	**940,688**
Reduction in "OK on Arrival" Outage Field Trips	0	0	0	0	135,529	280,680	581,288	601,924	623,292	645,419	668,331	692,057	716,625	742,065	768,408	795,687	823,934	**8,075,238**	**3,908,746**
Reduction in Field Trips for Voltage Investigations	0	0	0	0	74,833	154,978	320,960	332,354	344,152	356,370	369,021	382,121	395,686	409,733	424,279	439,341	454,937	**4,458,764**	**2,158,225**
TOTAL - Reduction in Field & Meter Services	*0*	*0*	*0*	*0*	*629,401*	*1,611,661*	*2,634,487*	*2,893,232*	*2,995,942*	*3,217,567*	*3,331,791*	*3,450,070*	*3,572,547*	*3,699,373*	*3,830,700*	*3,966,690*	*4,107,508*	*39,940,969*	*19,299,262*
Improved Distribution System Spend Efficiency																			
Efficiency gains reliability, asset health and capacity projects- O&M	0	0	0	0	1,159	2,401	4,972	5,148	5,331	5,520	5,716	5,919	6,129	6,347	6,572	6,805	7,047	**69,067**	**33,431**
TOTAL - Improved Distribution System Spend Efficiency	*0*	*0*	*0*	*0*	*1,159*	*2,401*	*4,972*	*5,148*	*5,331*	*5,520*	*5,716*	*5,919*	*6,129*	*6,347*	*6,572*	*6,805*	*7,047*	*69,067*	*33,431*
Outage Management Efficiency																			
Outage Management Efficiency (Storm spend O&M)	0	0	0	0	604	1,250	2,589	2,681	2,776	2,875	2,977	3,082	3,192	3,305	3,422	3,544	3,670	**35,965**	**17,409**
TOTAL - Outage Management Efficiency	*0*	*0*	*0*	*0*	*604*	*1,250*	*2,589*	*2,681*	*2,776*	*2,875*	*2,977*	*3,082*	*3,192*	*3,305*	*3,422*	*3,544*	*3,670*	35,965	17,409
TOTAL O&M BENEFITS	**2,155**	**86,393**	**1,085,789**	**2,460,063**	**4,371,835**	**5,203,171**	**6,795,840**	**7,189,000**	**7,430,524**	**7,788,455**	**8,043,175**	**8,306,268**	**8,578,011**	**8,858,691**	**9,148,602**	**9,448,050**	**9,757,350**	**104,553,371**	**52,805,408**
OTHER BENEFITS																			
Cost reductions																			
Reduced Consumption on Inactive Meters	0	0	0	0	350,052	714,596	1,458,776	1,488,973	1,519,795	1,551,255	1,583,366	1,616,141	1,649,595	1,683,742	1,718,595	1,754,170	1,790,482	**18,879,538**	**9,235,364**
Reduced Uncollectible / Bad Debt Expense	0	0	0	0	259,816	538,078	1,114,360	1,153,920	1,194,884	1,237,303	1,281,227	1,326,711	1,373,809	1,422,579	1,473,081	1,525,375	1,579,526	**15,480,670**	**7,493,278**
Reduced outage duration benefit	0	0	0	0	391,289	798,777	1,630,623	1,664,377	1,698,830	1,733,996	1,769,889	1,806,526	1,843,921	1,882,090	1,921,050	1,960,815	2,001,404	**21,103,587**	**10,323,309**
Theft / Tamper Detection & Reduction	0	0	0	0	847,310	1,729,700	3,531,009	3,604,101	3,678,706	3,754,855	3,832,580	3,911,915	3,992,891	4,075,544	4,159,908	4,246,018	4,333,911	**45,698,446**	**22,354,455**
TOTAL - Cost Reductions	0	0	0	0	1,848,467	3,781,151	7,734,769	7,911,371	8,092,215	8,277,408	8,467,062	8,661,292	8,860,217	9,063,955	9,272,633	9,486,379	9,705,322	***101,162,241***	***49,406,407***
Load Flexibility Benefits																			
Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	19,965,050	20,415,850	21,129,600	21,780,000	22,361,590	23,136,860	23,755,800	24,531,638	25,336,224	26,164,958	27,023,654	27,910,308	**283,511,530**	**138,479,332**
Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	1,819,116	1,975,194	2,019,888	2,037,750	2,133,144	2,262,273	2,392,520	2,517,599	2,573,992	2,725,849	2,753,107	2,780,638	**27,991,070**	**13,576,886**
Time Of Usage-TOU-Avoided CO2 Emissions	0	0	0	0	0	226,876	352,119	485,400	361,972	230,903	344,421	271,720	330,772	309,477	297,166	310,767	413,652	**3,935,245**	**1,961,868**
TOTAL - Load Flexibility Benefits	0	0	0	0	0	22,011,042	22,743,163	23,634,888	24,179,722	24,725,637	25,743,554	26,420,040	27,380,008	28,219,692	29,187,972	30,087,528	31,104,598	***315,437,845***	***154,018,085***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,848,467**	**25,792,193**	**30,477,932**	**31,546,259**	**32,271,937**	**33,003,045**	**34,210,616**	**35,081,332**	**36,240,224**	**37,283,648**	**38,460,605**	**39,573,907**	**40,809,920**	**416,600,086**	**203,424,492**
CAPITAL ITEMS																			
Capital gains and other avoided purchases																			
Efficiency gains reliability, asset health and capacity projects- CAP	0	0	0	0	189,547	386,940	789,900	806,251	822,940	839,975	857,363	875,110	893,225	911,715	930,587	949,850	969,512	**10,222,915**	**5,000,776**
Outage Management Efficiency (Storm spend CAP)	0	0	0	0	313,698	649,669	1,345,465	1,393,229	1,442,688	1,493,904	1,546,937	1,601,854	1,658,719	1,717,604	1,778,579	1,841,718	1,907,099	**18,691,164**	**9,047,289**
Avoided Meter Purchases	9,788	18,152	185,992	1,086,102	2,027,125	2,203,315	2,138,852	2,218,752	2,301,754	2,387,984	2,477,572	2,570,653	2,667,369	2,767,866	2,872,297	2,980,823	3,093,609	**34,008,006**	**17,455,428**
TOTAL - Efficiency gains and other avoided CAP purchases	9,788	18,152	185,992	1,086,102	2,530,369	3,239,924	4,274,216	4,418,231	4,567,383	4,721,863	4,881,872	5,047,617	5,219,313	5,397,185	5,581,464	5,772,392	5,970,221	***62,922,085***	***31,503,493***
Avoided Meter Reading CAP investment																			
Drive-by Meter Reading Cost - CAP	20,755	412,501	3,935,923	12,881,148	23,340,750	29,130,716	29,698,551	28,887,914	28,107,557	27,361,868	26,557,430	25,715,024	24,868,419	23,999,536	23,212,398	22,384,139	21,406,031	**351,920,659**	**189,681,697**
TOTAL - Avoided Meter Reading CAP Investment	*20,755*	*412,501*	*3,935,923*	*12,881,148*	*23,340,750*	*29,130,716*	*29,698,551*	*28,887,914*	*28,107,557*	*27,361,868*	*26,557,430*	*25,715,024*	*24,868,419*	*23,999,536*	*23,212,398*	*22,384,139*	*21,406,031*	*351,920,659*	*189,681,697*
TOTAL CAPITAL BENEFITS	**30,543**	**430,653**	**4,121,915**	**13,967,250**	**25,871,119**	**32,370,640**	**33,972,767**	**33,306,145**	**32,674,940**	**32,083,731**	**31,439,303**	**30,762,641**	**30,087,732**	**29,396,720**	**28,793,861**	**28,156,530**	**27,376,252**	**414,842,744**	**221,185,190**
GRAND TOTAL BENEFITS	**32,698**	**517,046**	**5,207,705**	**16,427,313**	**32,091,421**	**63,366,004**	**71,246,539**	**72,041,404**	**72,377,400**	**72,875,232**	**73,693,094**	**74,150,241**	**74,905,968**	**75,539,059**	**76,403,069**	**77,178,487**	**77,943,522**	**935,996,201**	**477,415,090**

NSPM -AMI- ***NPV***	**Total ($MM)**
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

RATIO SENSITIVITY	VALUE
FAN(80% WiMAx)+ Contingencies	0.83
FAN(80% WiMAx) NO Contingencies	0.99

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV	Cost Category
CAPITAL ITEMS - SUMMARY																							
FLISR Assets																							
Asset Cost	0	2,456,519	6,604,776	3,745,275	5,606,776	5,852,901	4,447,353	4,539,413	4,633,379	4,729,290	0	0	0	0	0	0	0	0	0	0	**42,615,682**	**29,507,829**	**Direct and Tangible**
Asset Installation	0	661,457	1,804,228	1,037,932	1,576,342	1,669,400	1,286,894	1,332,579	1,379,886	1,428,872	0	0	0	0	0	0	0	0	0	0	**12,177,590**	**8,386,388**	**Direct and Tangible**
Device related Vendor Project Management + Other Labor	0	15,533	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,533**	**13,712**	**Direct and Tangible**
Asset Contingency	0	0	0	1,499,386	1,866,899	919,536	604,982	617,505	630,288	643,334	0	0	0	0	0	0	0	0	0	0	**6,781,930**	**4,638,594**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***3,133,508***	***8,409,004***	***6,282,593***	***9,050,018***	***8,441,837***	***6,339,229***	***6,489,497***	***6,643,552***	***6,801,496***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***61,590,735***	**42,546,523**	
Communications Network																							
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Distribution WiMax	60,476	393,374	774,044	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,227,893**	**1,046,094**	**Direct and Tangible**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Bus Sys WiMAX Cost	62,744	1,877,077	3,245,488	2,178,488	2,061,470	558,087	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,983,353**	**7,998,909**	**Direct and Tangible**
FAN Bus Sys Contingency	48,467	831,493	1,478,676	765,585	724,462	196,129	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**4,044,811**	**3,268,006**	**Direct and Tangible**
TOTAL - Communications	171,686	3,101,943	5,498,207	2,944,073	2,785,932	754,216	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***15,256,057***	**12,313,008**	
IT Systems and Integration																							
ADMS FLISR Integration	0	372,780	503,962	521,853	1,023,270	1,059,597	807,499	836,165	865,849	896,587	0	0	0	0	0	0	0	0	0	0	**6,887,562**	**4,636,414**	**Direct and Tangible**
IT Contingency	0	0	0	299,788	632,358	654,807	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,586,953**	**1,147,107**	**Direct and Tangible**
TOTAL - IT Systems and Integration	***0***	***372,780***	***503,962***	***821,641***	***1,655,629***	***1,714,403***	***807,499***	***836,165***	***865,849***	***896,587***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8,474,515***	**5,783,521**	
TOTAL CAPITAL	**171,686**	**6,608,231**	**14,411,173**	**10,048,307**	**13,491,578**	**10,910,457**	**7,146,728**	**7,325,662**	**7,509,401**	**7,698,082**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**85,321,307**	**60,643,052**	
O&M ITEMS - SUMMARY																							
Deployment																							
O&M in support of capital deployment	0	85,389	229,582	130,186	194,892	203,447	154,590	157,790	161,056	164,390	0	0	0	0	0	0	0	0	0	0	**1,481,321**	**1,025,692**	**Direct and Tangible**
TOTAL - Asset Operations	***0***	***85,389***	***229,582***	***130,186***	***194,892***	***203,447***	***154,590***	***157,790***	***161,056***	***164,390***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,481,321***	**1,025,692**	
Ongoing Support																							
On-going Asset/Device support	0	9,416	34,927	50,006	72,532	96,468	115,512	135,303	155,864	177,218	180,886	184,630	188,452	192,353	196,335	200,399	204,547	208,781	213,103	217,514	**2,834,248**	**1,296,703**	**Direct and Tangible**
Component Replacements	0	2,742	10,171	14,562	21,121	28,092	33,637	39,400	45,387	51,606	52,674	53,764	54,877	56,013	57,173	58,356	59,564	60,797	62,056	63,340	**825,333**	**377,600**	**Direct and Tangible**
On-going Communications Network costs	0	7,324	27,166	38,894	56,414	75,031	89,843	105,236	121,227	137,836	140,689	143,601	146,574	149,608	152,705	155,866	159,092	162,386	165,747	169,178	**2,204,415**	**1,008,547**	**Direct and Tangible**
Vendor costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Training	0	10,355	10,723	11,103	11,497	11,906	12,328	12,766	13,219	13,688	14,174	14,677	15,199	15,738	16,297	16,875	17,474	18,095	18,737	19,402	**274,254**	**137,195**	**Direct and Tangible**
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
Asset Contingency	0	1,974	7,321	10,482	15,204	20,221	24,213	28,361	32,671	37,147	37,916	38,701	39,502	40,320	41,154	42,006	42,876	43,763	44,669	45,594	**594,092**	**271,804**	**Direct and Tangible**
TOTAL - Assets Cost	***0***	***31,810***	***90,308***	***125,047***	***176,769***	***231,717***	***275,533***	***321,066***	***368,368***	***417,495***	***426,339***	***435,374***	***444,604***	***454,032***	***463,663***	***473,502***	***483,554***	***493,822***	***504,312***	***515,028***	***6,732,342***	**3,091,849**	
Communications Network																							
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN WiMAX Cost	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	**Direct and Tangible**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Indirect and Tangible**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**	**Direct and Tangible**
TOTAL - Communications	43,800	66,983	80,091	81,429	105,420	196,509	122,551	0	0	0	0	0	0	0	0	0	0	0	0	0	**696,784**	**521,761**	
TOTAL O&M	**43,800**	**184,182**	**399,980**	**336,662**	**477,080**	**631,673**	**552,674**	**478,856**	**529,425**	**581,885**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**8,910,447**	**4,639,301**	
GRAND TOTAL CAPITAL & O&M	**215,486**	**6,792,413**	**14,811,154**	**10,384,969**	**13,968,659**	**11,542,130**	**7,699,402**	**7,804,518**	**8,038,826**	**8,279,967**	**426,339**	**435,374**	**444,604**	**454,032**	**463,663**	**473,502**	**483,554**	**493,822**	**504,312**	**515,028**	**94,231,754**	**65,282,354**	

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
O&M BENEFITS																						
Operational Benefits	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL O&M BENEFITS	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
CUSTOMER BENEFITS																						
Customer Minutes Out- CMO Patrolling savings	0	0	0	40,757	175,083	271,514	355,725	453,382	539,313	649,433	725,847	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	789,440	**10,316,013**	**4,528,044**
Customer Minutes Out- CMO Customer Savings	0	0	0	2,754,556	4,809,980	6,277,181	8,295,139	10,426,430	12,214,741	14,325,875	15,433,977	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	16,164,602	**220,019,300**	**98,458,717**
TOTAL CUSTOMER IMPACTS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**
GRAND TOTAL BENEFITS	**0**	**0**	**0**	**2,795,313**	**4,985,063**	**6,548,696**	**8,650,864**	**10,879,813**	**12,754,055**	**14,975,308**	**16,159,824**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**16,954,042**	**230,335,313**	**102,986,762**

NSPM FLISR- NPV

	Total ($MM)
Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(78)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

RATIO SENSITIVITY	VALUE
FAN(15% WiMax)+ Contingencies	**1.31**
FAN(15% WiMax) NO Contingencies	**1.53**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
Feeders enabled with IVVO	0	0	26	43	61	59	0	0	0	0	0	0	0	0	0	0	0	0	0	0	189	
CAPITAL COSTS																						
Assets/Devices																						
Device costs	0	0	1,512,735	2,824,978	2,704,856	2,267,749	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**9,310,319**	**6,996,776**
Device Installation costs	0	0	357,063	773,839	777,449	679,695	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,588,046**	**1,936,047**
Xcel Personnel	0	0	132,317	272,663	277,896	283,603	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**966,479**	**720,811**
Xcel Distribution Personnel [ADMS IVVO Integration]	0	0	306,666	525,184	771,477	772,672	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,375,999**	**1,760,061**
External resources (Consultants, contractors etc.)	0	0	187,008	434,397	443,389	342,887	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,407,681**	**1,054,169**
E&S	0	103,550	750,582	777,228	804,819	833,391	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,269,570**	**2,482,269**
Varentec Engineering (ENGO,caps,ami)	0	0	416,731	425,358	434,163	443,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,719,402**	**1,299,884**
Contingency	0	0	107,914	269,162	256,986	175,088	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**809,149**	**607,879**
TOTAL - Business Assets/Devices	***0***	***103,550***	***3,771,016***	***6,302,808***	***6,471,034***	***5,798,235***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***22,446,644***	***16,857,896***
Communications Network																						
Communications Operations-IVVO Budget	0	0	61,332	115,547	110,814	104,193	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**391,886**	**293,733**
FAN Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Distribution WiMax	20,159	131,125	258,015	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**409,298**	**348,698**
FAN Bus Sys Costs	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Bus Sys WiMAX Cost	20,915	625,692	1,081,829	726,163	687,157	186,029	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,327,784**	**2,666,303**
FAN Bus Sys Contingency	0	0	0	1,482,861	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,482,861**	**1,155,589**
TOTAL - Communications	41,073	756,817	1,401,176	2,324,571	797,971	290,222	0	0	0	0	0	0	0	0	0	0	0	0	0	0	***5,611,829***	4,464,323
IT Systems and Integration																						**0**
Xcel Personnel [ADMS IVVO Integration]	0	0	803,466	1,375,982	2,021,270	2,024,401	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**6,225,118**	**4,611,361**
External resources (Consultants, contractors etc.) [GEMS]	0	0	520,914	265,849	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**786,763**	**639,234**
GEMS hardware	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Varentec PM & Services	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Project Management	0	0	52,091	26,585	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**78,676**	**63,923**
IT Travel Expenses	0	0	10,418	5,317	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**15,735**	**12,785**
Security	0	0	104,183	53,170	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**157,353**	**127,847**
Contingency	0	0	130,158	158,367	190,817	188,381	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**667,722**	**500,682**
Program Management	0	0	104,183	319,018	325,622	332,362	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**1,081,185**	**802,089**
TOTAL - IT Systems and Integration	***0***	***0***	***1,881,688***	***2,284,042***	***2,537,708***	***2,545,144***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***9,248,582***	6,949,692
Program Management																						
Organizational Change Management	0	0	468,823	850,715	651,244	553,937	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**2,524,720**	**1,909,732**
TOTAL - Program Management	***0***	***0***	***468,823***	***850,715***	***651,244***	***553,937***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***2,524,720***	**1,909,732**
TOTAL CAPITAL	**41,073**	**860,367**	**7,522,703**	**11,762,136**	**10,457,957**	**9,187,538**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**39,831,775**	**30,181,642**
O&M ITEMS																						
O&M in support of capital deployment	0	0	17,731	37,764	33,658	34,745	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**123,898**	**92,683**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***17,731***	***37,764***	***33,658***	***34,745***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***				***123,898***	92,683
Assets/Devices																						
On-going Asset/Device support	0	0	0	0	7,991	25,537	40,714	57,063	59,089	61,187	63,359	65,608	67,937	70,349	72,847	75,433	78,110	80,883	83,755	86,728	**996,591**	**433,842**
Device Replacements	0	0	0	0	12,059	38,654	62,172	85,943	87,722	89,538	91,391	93,283	95,214	97,185	99,197	101,250	103,346	105,485	107,669	109,897	**1,380,003**	**609,942**
Training	0	0	0	0	195	653	1,107	1,554	1,609	1,666	1,725	1,786	1,850	1,915	1,983	2,054	2,127	2,202	2,280	2,361	**27,066**	**11,765**
Contingency	0	0	0	0	2,471	7,885	12,612	17,431	17,792	18,160	18,536	18,920	19,312	19,711	20,119	20,536	20,961	21,395	21,838	22,290	**279,968**	**123,761**
TOTAL - On-going Asset/Device support Costs	***0***	***0***	***0***	***0***	***22,715***	***72,730***	***116,604***	***161,991***	***166,212***	***170,551***	***175,011***	***179,597***	***184,312***	***189,161***	***194,146***	***199,272***	***204,544***	***209,965***	***215,541***	***221,276***	***2,683,629***	1,179,310
Communications Network																						
On-going Communications Network costs	0	0	0	0	4,920	15,829	25,585	35,371	36,103	36,850	37,613	38,392	39,187	39,998	40,826	41,671	42,533	43,414	44,312	45,230	**567,832**	**250,941**
FAN Network Infrastructure Distribution	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Business Systems	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN WiMAX Cost	14,600	22,328	26,697	27,143	35,140	65,503	40,850	0	0	0	0	0	0	0	0	0	0	0	0	0	**232,261**	**173,920**
NOC Opco Allocation	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Distribution Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
FAN Network Bus Sys Contingency	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	**0**
TOTAL - Communications	***14,600***	***22,328***	***26,697***	***27,143***	***40,060***	***81,332***	***66,435***	***35,371***	***36,103***	***36,850***	***37,613***	***38,392***	***39,187***	***39,998***	***40,826***	***41,671***	***42,533***	***43,414***	***44,312***	***45,230***	***800,094***	424,861
IT Systems and Integration																						
Program Management	0	0	22,576	35,446	36,180	36,929	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**131,132**	**98,245**
TOTAL - IT Systems and Integration	***0***	***0***	***22,576***	***35,446***	***36,180***	***36,929***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***131,132***	98,245
Business Program Management																						
Organizational Change Management	0	0	156,274	283,572	217,081	184,646	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**841,573**	**636,577**
TOTAL - Program Management	***0***	***0***	***156,274***	***283,572***	***217,081***	***184,646***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***841,573***	636,577
TOTAL O&M	**14,600**	**22,328**	**223,278**	**383,926**	**349,694**	**410,382**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**4,580,325**	**2,431,676**
GRAND TOTAL CAPITAL & O&M	**55,673**	**882,695**	**7,745,981**	**12,146,062**	**10,807,651**	**9,597,920**	**183,039**	**197,362**	**202,315**	**207,401**	**212,625**	**217,989**	**223,499**	**229,158**	**234,971**	**240,943**	**247,077**	**253,379**	**259,854**	**266,506**	**44,412,100**	**32,613,318**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	TOTAL	NPV
OTHER BENEFITS																						
Energy Savings																						
Energy Reduction	0	0	165,891	423,491	910,125	1,577,997	1,904,520	1,963,148	2,014,173	2,063,569	2,041,390	1,994,758	2,019,200	2,085,180	2,025,146	2,026,282	2,185,792	2,206,891	2,172,820	2,129,363	**31,909,736**	$14,934,748
Loss Savings	0	0	3,155	8,234	18,167	32,238	39,806	41,776	43,440	44,870	45,454	45,229	46,713	49,088	48,089	48,350	52,370	53,018	52,442	52,442	**724,883**	$333,272
Total Fuel Savings	0	0	169,046	431,724	928,293	1,610,235	1,944,326	2,004,924	2,057,613	2,108,438	2,086,844	2,039,988	2,065,913	2,134,268	2,073,236	2,074,632	2,238,162	2,259,909	2,225,262	2,181,806	**32,634,620**	$15,268,020
Carbon Emissions Benefits																						
Carbon Reduction	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
Total Carbon Emissions Savings	0	0	94,698	230,703	479,367	643,180	656,339	645,988	537,529	340,791	312,713	309,097	303,111	284,879	316,482	328,421	341,160	345,262	349,364	353,466	**6,872,548**	$3,599,824
TOTAL OTHER BENEFITS	**0**	**0**	**263,744**	**662,427**	**1,407,660**	**2,253,415**	**2,600,664**	**2,650,912**	**2,595,141**	**2,449,229**	**2,399,557**	**2,349,085**	**2,369,024**	**2,419,147**	**2,389,718**	**2,403,054**	**2,579,322**	**2,605,171**	**2,574,626**	**2,535,271**	**39,507,168**	**$18,867,844**
DEMAND BENEFITS																						
Deferral of Capital Investments As Demand Reduction	0	0	45,106	113,532	227,415	386,537	456,612	457,807	459,632	460,716	460,890	465,302	468,166	470,601	475,990	480,620	485,452	488,836	495,037	489,665	**7,387,915**	$3,481,566
TOTAL DEMAND	**0**	**0**	**45,106**	**113,532**	**227,415**	**386,537**	**456,612**	**457,807**	**459,632**	**460,716**	**460,890**	**465,302**	**468,166**	**470,601**	**475,990**	**480,620**	**485,452**	**488,836**	**495,037**	**489,665**	**7,387,915**	**$3,481,566**
GRAND TOTAL DEMAND & OTHER BENEFITS	**0**	**0**	**308,850**	**775,959**	**1,635,075**	**2,639,951**	**3,057,277**	**3,108,719**	**3,054,774**	**2,909,945**	**2,860,447**	**2,814,387**	**2,837,189**	**2,889,748**	**2,865,708**	**2,883,673**	**3,064,774**	**3,094,007**	**3,069,663**	**3,024,937**	**46,895,083**	**$22,349,410**

NSPM IVVO- NPV

	Total ($MM)
Benefits	**22**
Other Benefits	19
CAP Benefits	3
Costs	**(39)**
O&M Expense	(2)
Change in Revenue Requirement	(37)
Benefit/Cost Ratio (DVO 1.25% O&M; 0.7% capital)	**0.57**

RATIO BASE (DVO Savings 1.25% O&M, 0.7% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.57**
FAN(5% WiMax) NO Contingencies	**0.61**

RATIO LOW SENSITIVITY (DVO Savings 1% O&M, 0.6% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.46**
FAN(5% WiMax) NO Contingencies	**0.49**

RATIO HIGH SENSITIVITY (DVO Savings 1.5% O&M, 0.8% CAP)	VALUE
FAN(5% WiMax)+ Contingencies	**0.67**
FAN(5% WiMax) NO Contingencies	**0.72**

	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	TOTAL	NPV
Total Meters Replaced	*10,131*	*7,368*	*121,800*	*630,000*	*590,000*	*40,700*	*13,755*	*13,890*	*14,027*	*14,164*	*14,304*	*14,444*	*14,586*	*14,729*	*14,874*	*15,020*	*15,168*	***1,558,960***	
OTHER BENEFITS																			
Load Flexibility Benefits																			
Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	19,965,050	20,415,850	21,129,600	21,780,000	22,361,590	23,136,860	23,755,800	24,531,638	25,336,224	26,164,958	27,023,654	27,910,308	**283,511,530**	**138,479,332**
Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	1,819,116	1,975,194	2,019,888	2,037,750	2,133,144	2,262,273	2,392,520	2,517,599	2,573,992	2,725,849	2,753,107	2,780,638	**27,991,070**	**13,576,886**
Time Of Usage-TOU-Avoided CO2 Emissions	0	0	0	0	0	226,876	352,119	485,400	361,972	230,903	344,421	271,720	330,772	309,477	297,166	310,767	413,652	**3,935,245**	**1,961,868**
TOTAL - Load Flexibility Benefits	0	0	0	0	0	22,011,042	22,743,163	23,634,888	24,179,722	24,725,637	25,743,554	26,420,040	27,380,008	28,219,692	29,187,972	30,087,528	31,104,598	***315,437,845***	***154,018,085***
TOTAL OTHER BENEFITS	**0**	**0**	**0**	**0**	**1,848,467**	**25,792,193**	**30,477,932**	**31,546,259**	**32,271,937**	**33,003,045**	**34,210,616**	**35,081,332**	**36,240,224**	**37,283,648**	**38,460,605**	**39,573,907**	**40,809,920**	**416,600,086**	**203,424,492**

The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory

PREPARED FOR

Xcel Energy

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Notice

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Executive Summary

Highlights:

- This study estimates the amount of cost-effective demand response available in Xcel Energy's Northern States Power (NSP) service territory, including an assessment of emerging "load flexibility" programs that can capture advanced sources of value such as geo-targeted distribution investment deferral and grid balancing services.
- Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and grid balancing services, and relatively high costs of emerging DR technologies.
- In later years of the study horizon, and under conditions that are more favorable to the economics of DR, cost-effective DR potential increases significantly, exceeding the PUC's 400 MW DR procurement requirement.
- New, emerging load flexibility programs account for around 30% of the 2030 incremental DR potential estimates in this study.

Background

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory through 2030.[1] The study addresses the Minnesota PUC's requirement that NSP "acquire no less than 400 MW of additional demand response by 2023" and "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

The scope of this study extends significantly beyond those of prior studies. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies

[1] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions.

This study also takes a detailed approach to assessing the cost-effectiveness of each DR option. While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

The Brattle Group's Load*Flex* model is used to assess NSP's emerging DR opportunities. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of load flexibility programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program, thus providing a more complete estimate of total cost-effective potential than prior methodologies.
- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. This includes accounting for the market saturation of various end-use appliances, customer segmentation based on size, and NSP's estimates of the capability of its existing DR programs.
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program, including tariff-related program limitations and an hourly representation of load control capability for each program.
- **Realistic accounting for "value stacking":** DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program and accounting for necessary tradeoffs when pursuing multiple value streams.
- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings, a review of experience and studies in other jurisdictions, and conversations with vendors.

Findings

Base Case

NSP currently has one of the largest DR portfolios in the country, with 850 MW of load curtailment capability (equivalent to roughly 10% of NSP's system peak). The portfolio primarily consists of an interruptible tariff program for medium and large C&I customers, and a residential air-conditioning direct load control (DLC) program. The DLC program is transitioning from utilizing a conventional compressor switch technology to instead leveraging newer smart thermostats.

There is an opportunity to tap into latent interest in the current NSP programs and grow participation in those existing programs through new marketing efforts. According to our analysis, doing so could provide 293 MW of incremental cost-effective potential by 2023. The majority of this growth could come from increased enrollment in the interruptible tariff program for the medium and large C&I segments, and from the transition to a residential air-conditioning DLC program that more heavily utilizes smart thermostat technology.

NSP's DR portfolio could also be expanded to include new programs that are not currently offered by the company. Our analysis considered eight new programs, including time-of-use (TOU) rates, critical peak pricing (CPP), home and workplace EV charging load control, timer-based water heating load control and a more advanced "smart" water heating program, behavioral DR, ice-based thermal storage, and automated DR for lighting and HVAC of commercial and industrial customers. Some of these programs could provide ancillary services and geo-targeted distribution deferral benefits, in addition to the conventional DR value streams.

Based on current expectations about the future characteristics of the NSP market, smart water heating is the only new program that we find to be cost-effective in 2023 among the emerging options described above, providing an additional 13 MW of incremental cost-effective potential. Through 2023, NSP's cost-effective DR opportunities are constrained by limitations of its existing metering technology, access to low-cost peaking capacity, a limited need for distribution capacity deferral and frequency regulation, and relatively high costs of emerging DR technologies.

This expanded portfolio, which reflects all cost-effective DR options available to NSP across a broad range of potential use cases, would fall short of the PUC's 2023 procurement requirement. In 2023, the current portfolio plus the incremental cost-effective DR identified in this study would equate to 1,156 MW of total peak reduction capability, 154 MW short of the procurement requirement.[2]

In 2025, the potential in the expanded portfolio increases. This increase is driven primarily by the ability to begin offering time-varying rates once smart meters are fully deployed in 2024. However, it is likely that several years will be needed for smart metering-based programs to ramp up to full participation, so the incremental potential associated with these programs is still somewhat constrained in 2025. The current portfolio plus the incremental DR in the expanded portfolio equate to 1,243 MW of cost-effective DR potential in 2025.

2 NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when additionally accounting for line losses.

By 2030, NSP's cost-effective DR potential will increase further. This increase is driven primarily by the maturation of smart metering-based DR programs. Other factors contributing to the increase in cost-effective potential include a continued transition to air-conditioning load control through smart thermostats, an expansion of the smart water heating program through ongoing voluntary replacements of expiring conventional electric water heaters, and overall growth in NSP's customer base. By 2030, we estimate that NSP's current portfolio plus the incremental cost-effective DR would amount to 468 MW. New, emerging DR programs account for 33% of the incremental potential. Achieving this potential would require not only growth in existing programs, but the design and implementation of several new DR program as well.

High Sensitivity Case

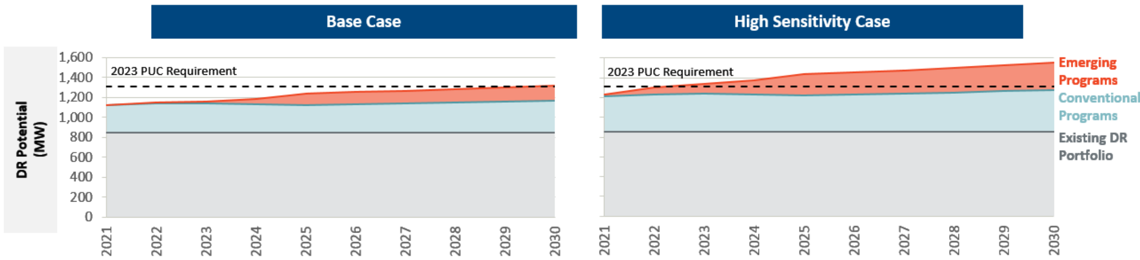
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the costs of emerging DR technologies may decline significantly, or the cost of competing resources (e.g., peaking capacity) may be higher than expected. To understand how these alternative conditions would impact DR potential, we analyzed a sensitivity case. The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. The case is not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative assumptions of the High Sensitivity Case there is significantly more cost-effective incremental potential. In 2023 there is a total of 484 MW of incremental cost effective potential, which would satisfy the PUC's procurement requirement. By 2030, the total portfolio of DR programs, including the existing programs, could reach 705 MW.

The mix of cost-effective programs in the High Sensitivity case is essentially the same as in the Base Case. However, larger program benefits justify higher incentive payments, which leads to higher participation and overall potential in these programs. Auto-DR for C&I customers also presents an opportunity to increase load flexibility in the High Sensitivity Case, though the potential in this program is subject to uncertainty in technology cost and customer adoption.

Under both the Base Case and the High Sensitivity Case assumptions, avoided generation capacity costs are the primary benefit of the DR portfolio. In the High Sensitivity Case, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Figure ES-1 summarizes the DR potential estimates and benefits of the DR portfolio under Base Case and High Sensitivity Case assumptions.

Figure ES-1: NSP's DR Potential and Annual Portfolio Benefits



2030 Avoided Cost ($M/yr)

Base Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

High Sensitivity Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

An expanded portfolio of DR programs will have operational flexibility beyond the capabilities of conventional existing programs. For instance, load flexibility programs could be dispatched to reduce the system peak, but also to address local peaks on the distribution system which may occur during later hours of the day. Off-peak load building through electric water heating could help to mitigate wind curtailments and take advantage of negative energy prices. The provision of frequency regulation from electric water heaters could further contribute to renewables integration value.

Specific recommendations for acting on the findings of this study including the following:

- Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program.
- Pilot and deploy a smart water heating program. As a complementary activity, evaluate the impacts of switching from gas to electric heating, accounting for the grid reliability benefits associated with this flexible source of load.
- Prior to the smart metering rollout, build the foundation for a robust offering of time-varying rates, including identifying rate options that could be offered on an opt-out basis.
- Develop measurement & verification (M&V) 2.0 protocols to ensure that program impacts are dependable and can be integrated meaningfully into resource planning efforts.
- Design programs with peak period flexibility, to be able to respond to changes such as a shifts in the net peak due to solar PV adoption, or a shift in the planning emphasis from a focus on the MISO peak to a focus on more local peaks, for instance.

I. Introduction

Purpose

The purpose of this study is to estimate the potential capability of all cost-effective demand response (DR) that could be deployed in Xcel Energy's Northern States Power (NSP) service territory.[3] Xcel Energy commissioned this study to satisfy the requirements of the Minnesota Public Utilities Commission (PUC) Order in Docket No. E-002/RP-15-21. That Order, established in January 2017, required NSP to "acquire no less than 400 MW of additional demand response by 2023" and to "provide a full and thorough cost-effectiveness study that takes into account the technical and economic achievability of 1,000 MW of additional demand response, or approximately 20% of Xcel's system peak in total by 2025."

Background

The Brattle Group conducted an assessment of NSP's DR potential in 2014.[4] That study specifically addressed opportunities to reduce NSP's system peak demand. As such, the assessment had a primary focus on "conventional" DR programs that are utilized infrequently to mitigate system reliability concerns. The study also included price-based DR options that would be enabled by the eventual deployment of smart meters.

The scope of this 2018 study extends significantly beyond that of the 2014 study. Specifically, we account for opportunities enabled by the rapid emergence of consumer-oriented energy technologies. Advanced metering infrastructure (AMI), smart appliances, electric vehicles, behavioral tools, and automated load control for large buildings are just a few of the technologies driving a resurgence of interest in the value that can be created through new DR programs. These technologies enable DR to evolve from providing conventional peak shaving services to providing around-the-clock "load flexibility" in which electricity consumption is managed in real-to address economic and system reliability conditions. The Brattle Group's Load*Flex* model is used to assess these emerging opportunities.

[3] Throughout this study, we simply refer to Xcel Energy as "NSP" when describing matters relevant to its NSP service territory.

[4] Ryan Hledik, Ahmad Faruqui, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," prepared for Xcel Energy, April 2014.

This 2018 study also extends beyond the scope of the 2014 study by evaluating the cost-effectiveness of each DR option.[5] While emerging DR programs introduce the potential to capture new value streams, they are also dependent on technologies that in some cases have not yet experienced meaningful cost declines. Further, opportunities to create value through DR vary significantly from one system to the next. A utility with significant market penetration of solar PV may find the most value in advanced load shifting capabilities that address evening generation ramping issues on a daily basis, whereas a system with a near-term need for peaking capacity may find more value in the types of conventional DR programs that reduce the system peak during only a limited number of hours per year. A detailed assessment of the costs and benefits of each available DR option is necessary to identify the DR portfolio that is the right "fit" for a given utility system.

This report summarizes the key findings of The Brattle Group's assessment of NSP's DR market potential. Additional detail on methodology and results is provided in the appendices.

NSP's Existing DR Portfolio

The capability of NSP's existing DR portfolio is substantial. It is the eighth largest portfolio among all US investor-owned utilities when DR capability is expressed as a percentage of peak demand. The portfolio is the largest in MISO in terms of total megawatt capability, and second when expressed as a percentage of peak demand.

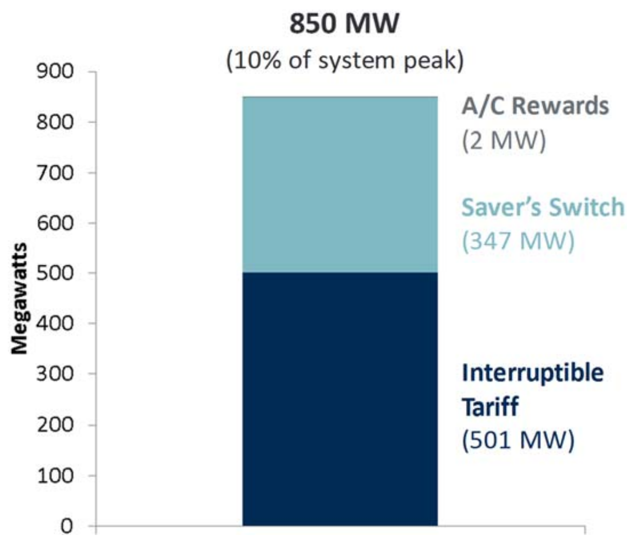
As of 2017, Xcel Energy had 850 MW of DR capability across its NSP service territory, accounting for roughly 10 percent of system peak demand. This capability comes primarily from two programs. The largest is an "interruptible tariff" program, which provides commercial and industrial (C&I) customers with energy bill savings in return for a commitment to curtail electricity demand to pre-established levels when called upon by the utility. Roughly 11 percent of the peak-coincident demand of medium and large C&I customers is enrolled in this program.

The second program is NSP's Saver's Switch program. Saver's Switch is a conventional residential load control program, in which the compressor of a central air-conditioning unit or the heating element of an electric resistance water heater is temporarily cycled off to reduce electricity demand during DR events. Saver's Switch is one of the largest such programs in the country. Roughly 52 percent of all eligible residential customers (i.e., those with central air-conditioning) are enrolled in the program, accounting for around 29% of all of NSP's residential customers. Saver's Switch is gradually being transitioned to a program based on newer smart thermostat technology, called "A/C Rewards." A/C Rewards contributes an additional 2 MW to

[5] The 2014 study developed a "supply curve" of DR options available to NSP as inputs to its integrated resource plan (IRP), but did not explicitly evaluate the extent to which those options would be less costly than serving electricity demand through the development of new generation resources.

NSP's existing DR capability, though this is expected to grow significantly in coming years. A summary of NSP's DR portfolio is provided in Figure 1.

Figure 1: NSP 2017 DR Capability



Sources: NSP 2017 DR program data and 2017 NSP system peak demand (8,546 MW)

Important Considerations

The focus of this study is on quantifying the amount of cost-effective DR capability that can be achieved above and beyond NSP's current 850 MW DR portfolio. We estimate the incremental DR potential that can be achieved through an expansion of existing program offerings, the introduction of new programs, and consideration of a broad range of potential system benefits that are available through DR. Specifically, this study is structured to quantify all DR potential that satisfies the following three conditions:

1. **Incremental:** All quantified DR potential is incremental to NSP's existing 850 MW DR portfolio.[6]

2. **Cost-effective:** The present value of avoided resource costs (i.e., benefits) must outweigh program costs, equipment costs, and incentives.

[6] For the purposes of this analysis, all incremental potential estimates assume NSP's portfolio of existing programs continues to be offered as currently designed in future years, and that the 850 MW impact persists throughout the forecast horizon.

3. **Achievable:** Program enrollment rates are based on primary market research in NSP's service territory and supplemented with information about utility experience in other jurisdictions.

The findings of this study should be interpreted as a quantitative screen of the DR opportunities available to NSP. Further development of individual programs, and testing of the programs through pilots, will provide additional insight regarding the potential benefits and costs that such programs may offer to NSP and its customers when deployed on a full scale basis.

II. Methodology

This study analyzes three ways to increase the capability of NSP's existing DR portfolio. First, we assess the potential to increase enrollment in existing programs. Increased enrollment could be achieved through targeted program marketing efforts, for example. Second, the menu of DR programs offered to customers could be expanded to include new, non-conventional options. These non-conventional options include emerging "load flexibility" programs which go beyond peak shaving to provide around-the-clock decreases and increases in system load. Third, consistent with the introduction of more flexible DR programs, we consider a broadened list of potential benefits in the cost-effectiveness screening process, such as ancillary services and geographically-targeted deferral of distribution capacity upgrades.

Conventional DR Programs

Our analysis considers conventional DR programs that have been offered by utilities for many years, including in some cases by NSP.

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch on the compressor. The modeled program is based on NSP's Savers Switch program.

- **Smart thermostats:** An alternative to conventional DLC, smart thermostats allow the temperature setpoint to be remotely controlled to reduce A/C usage during peak times. The modeled program is based on NSP's A/C Rewards program, which provides customers with options to use their own thermostat, self-install a thermostat purchased from NSP's online store, or use a NSP-installed thermostat. Smart thermostat programs are based on newer technology than the other "conventional" DR programs in this list, but included here as the program is already offered by NSP.

- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate.

- **Demand bidding:** Participants submit hourly curtailment schedules on a daily basis and, if the bids are accepted, must curtail the bid load amount to receive the bid incentive payment or may be subject to a non-compliance penalty. While a conventional option, demand bidding is not currently offered by NSP.

Non-conventional DR Programs

Pricing programs are one type of non-conventional DR option. We consider two specific time-varying rate options which generally span the range of impacts that can be achieved through pricing programs: A static time-of-use rate and a dynamic critical peak pricing rate.

- **Time-of-use (TOU) rate:** Currently being piloted by NSP for residential customers and offered on a full-scale basis to C&I customers. Static price signal with higher price during peak hours (assumed 5-hour period aligned with system peak) on non-holiday weekdays. Modeled as being offered on an opt-in and an opt-out (default) basis. The study also includes an optional TOU rate for EV charging.

- **Critical peak pricing (CPP) rate:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1/kWh) during peak hours on 10 to 15 days per year. CPP rates are modeled as being offered on both an opt-in and an opt-out (default) basis.

The second category of non-conventional DR programs relies on a variety of advanced behavioral and technological tools for managing customer electricity demand.

- **Behavioral DR:** Customers are informed of the need for load reductions during peak times without being provided an accompanying financial incentive. Customers are typically informed of the need for load reductions on a day-ahead basis and events are called somewhat sparingly throughout the year. Behavioral DR programs have been piloted by several utilities, including Consumers Energy, Green Mountain Power, the City of Glendale, Baltimore Gas & Electric, and four Minnesota cooperatives.

- **EV managed charging:** Using communications-enabled smart chargers allows the utility to shift charging load of individual EVs plugged-in from on-peak to off-peak hours. Customers who do not opt-out of an event receive a financial incentive. The managed EV charging program was modeled on three recent pilots: PG&E (with BMW), United Energy (Australia), and SMUD. Allows curtailment of charging load for up to three hours per day, fifteen days per year. Impacts were modeled for both home charging and workplace charging programs.

- **Timed water heating:** The heating element of electric resistance water heaters can be set to heat water during off-peak hours of the day. The thermal storage capabilities of the water tank provide sufficient hot water during peak hours without needing to activate the heating element.

- **Smart water heating:** Offers improved flexibility and functionality in the control of the heating element in the water heater. The thermostat can be modulated across a range of temperatures. Multiple load control strategies are possible, such as peak shaving, energy price arbitrage through day/night thermal storage, or the provision of ancillary services such as frequency regulation. Modeled for electric resistance water heaters, as these represent the vast majority of electric water heaters and are currently the most attractive candidates for a range of advanced load control strategies.

- **Ice-based thermal storage:** Commercial customers shift peak cooling demand to off-peak hours using ice-based storage systems. The thermal storage unit acts as a battery for the customer's A/C unit, charging at night (freezing water) and discharging (allowing ice to thaw to provide cooling) during the day.

- **C&I Auto-DR:** Auto-DR technology automates the control of various C&I end-uses. Features of the technology allow for deep curtailment during peak events, moderate load shifting on a daily basis, and load increases and decreases to provide ancillary services. Modeled end-uses include HVAC and lighting (both luminaire and zonal lighting options).

DR Benefits

This study accounts for value streams that are commonly included in assessments of DR potential:

- **Avoided generation capacity costs:** The need for new peaking capacity can be reduced by lowering system peak demand. Important considerations when estimating the equivalence of DR and a peaking generation unit are discussed later in this section of the report.

- **Reduced peak energy costs:** Reducing load during high priced hours leads to a reduction in energy costs. Our analysis estimates net avoided energy costs, accounting for costs associated with the increase in energy consumption during lower cost hours due to "load building." The energy benefit accounts for avoided average line losses. Our analysis likely includes a conservative estimate of this value, as peak line losses are greater than off-peak line losses. Our analysis does not include the effect of any potential change in energy market prices that may result from changes in load patterns (sometimes referred to as the "demand response induced price effect," or DRIPE). It is simply a calculation of reduced resource costs.

- **System-wide deferral of transmission and distribution (T&D) capacity costs.** System-wide reductions in peak demand can, on average, contribute to the reduced need for peak-driven upgrades in T&D capacity. We account for this potential value using methods that were established in a recent Minnesota PUC proceeding.[7]

This study also accounts for value streams that can be captured through more advanced DR programs:

- **Geo-targeted distribution capacity investment deferral:** DR participants may be recruited in locations on the distribution system where load reductions would defer the need for capacity upgrades. NSP's 5-year distribution plan was used to identify candidate deferral projects, and qualifying DR programs were evaluated based on their ability to contribute to the deferral.[8]

- **Ancillary services:** The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service (albeit with limited system need).

- **Load building / valley filling:** Load can be shifted to off-peak hours to reduce wind curtailments or take advantage of low or negatively priced hours. DR was dispatched against hourly energy price series to capture the economic incentive that energy prices provide for this service.

Figure 2 summarizes the ways in which this assessment of DR potential extends the scope of prior studies in Minnesota and other jurisdictions. In the figure, "X" indicates the value streams that each DR program is assumed to provide.

7 Minnesota PUC Docket No. E999/CIP-16-541.

8 The distribution plan was in-development at the time of our analysis. Distribution data was provided to Brattle in March 2018.

Figure 2: Options for Expanding the Existing DR Portfolio

1 Increase enrollment in the conventional portfolio

2 Extend DR value streams

3 Include non-traditional DR options

	Generation capacity avoidance	Reduced peak energy costs	System peak related T&D deferral	Targeted distribution capacity deferral	Valley filling/ Load building	Ancillary services
Direct load control (DLC)	X	X	X			
Interruptible tariff	X	X	X			
Demand bidding	X	X	X		X	
Smart thermostat	X	X	X			
Time-of-use (TOU) rates	X	X	X			
Dynamic pricing	X	X	X			
Behavioral DR	X	X	X			
EV managed charging	X	X	X	X	X	
Smart water heating	X	X	X		X	X
Timed water heating	X	X	X		X	
Ice-based thermal storage	X	X	X	X	X	
C&I Auto-DR	X	X	X	X	X	X

Notes: "X" indicates the value streams that each DR option is assumed to be able to provide.

Defining DR Potential

We use the Utility Cost Test (UCT), also known as the Program Administrator Cost Test (PACT), to determine the cost-effectiveness of the incremental DR portfolio. The UCT determines whether a given DR program will increase or decrease the utility's revenue requirement. This is the same perspective that utilities take when deciding whether or not to invest in a supply-side resource (e.g., a combustion turbine) through the IRP process.[9] Since the purpose of this DR potential study is to determine the amount of DR that should be included in the IRP, the UCT was determined to be the appropriate perspective. Major categories of benefits and costs included in the UCT are summarized Table 1.

9 According to the National Action Plan for Energy Efficiency: "The UCT is the appropriate cost test from a utility resource planning perspective, which typically aims to minimize a utility's lifecycle revenue requirements."

Table 1: Categories of Benefits and Costs included in the Utility Cost Test

Benefits	Costs
Avoided generation capacity	Incentive payments
Avoided peak energy costs	Utility equipment & installation
Avoided transmission capacity	Administration/overhead
Avoided distribution capacity	Marketing/promotion
Ancillary services	

Throughout this study, we quantify DR potential in two different ways:

Technical Potential: Represents achievable potential without consideration for cost-effectiveness. In other words, this is a measure of DR capability that could be achieved from anticipated enrollment associated with a moderate participation incentive payment, regardless of whether or not the incentive payment and other program costs exceed the program benefits. As it is used here, the term "technical potential" differs from its use in energy efficiency studies. Technical potential in energy efficiency studies assumes 100% participation, whereas we assume an achievable level of participation in this assessment of DR potential.

Cost-effective Potential: Represents the portion of technical potential that can be obtained at cost-effective incentive payment levels. For each program, the assumed participation incentive payment level is set such that the benefit-cost ratio is equal to 1.0. Participation rates are estimated to align with this incentive payment level. When non-incentive costs (e.g., equipment and installation costs) are found to outweigh the benefits alone, the benefit-cost ratio is less than 1.0 and there is no opportunity to offer a cost-effective participation incentive payment. In that case, the program is considered to have no cost-effective potential.

The Load*Flex* Model

The Brattle Group's Load*Flex* model was used to estimate DR potential in this study. The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of NSP's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to NSP's experience with DR programs where available (e.g., impacts from existing DLC programs or dynamic pricing pilots).

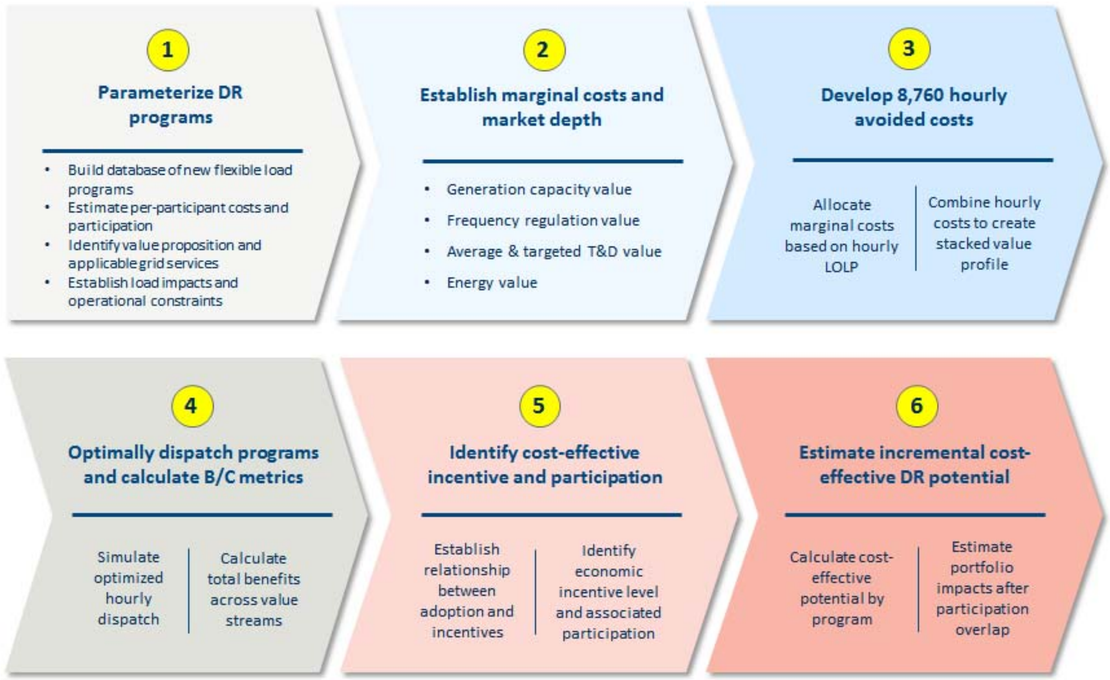
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local transmission or distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies of load flexibility value have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of NSP's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* modeling framework is organized around six steps, as summarized in Figure 3. Appendix A provides detail on the methodology behind each of these steps.

Figure 3: The Load*Flex* Modeling Framework



Modeling Scenarios

The value that DR will provide depends on the underlying conditions of the utility system in which it is deployed. Generation capacity costs, the anticipated need for new transmission and distribution (T&D) assets, and energy price volatility are a few of the factors that will determine DR value and potential. To account for uncertainty in NSP's future system conditions, we considered two modeling scenarios: A "Base Case" and a "High Sensitivity Case."

The **Base Case** most closely aligns with NSP's expectations for future conditions on its system, as defined in its IRP. The Base Case represents a continuation of recent market trends, combined with information about known or planned developments during the planning horizon.

The **High Sensitivity Case** was developed to illustrate how the value of DR can change under alternative future market conditions. The High Sensitivity Case is defined by assumptions about the future state of the NSP system and MISO market that are more favorable to DR program economics. The High Sensitivity Case is not intended to be the most likely future state of the NSP system. Relative to the Base Case, the High Sensitivity Case consists of a higher assumed generation capacity cost, more volatile energy prices due to greater market penetration of renewable generation, a significant reduction in emerging DR technology costs, and an increase in the need for frequency regulation.

Defining features of the two cases are summarized in Table 2. Appendix A includes more detail on assumptions and data sources behind the two cases.

Table 2: Defining Features of Base Case and High Sensitivity Case

	Base Case	High Sensitivity Case
Generation capacity (Net CONE)	\$64/kW-yr (2018 NSP IRP)	\$93/kW-yr (2018 EIA Annual Energy Outlook)
Hourly energy price	Based on MISO MTEP "Continued Fleet Change" case (15% wind+solar by 2032)	Based on MISO MTEP "Accelerated Fleet Change" case (30% wind+solar by 2032)
Frequency regulation	Price varies, 25 MW average need by 2030	Price same as Base Case, 50 MW average need by 2030
System average T&D deferral	Transmission: \$3.6/kW-yr, Distribution: \$9.5/kW-yr (2017 NSP Avoided T&D Study)	Same as Base Case
Geo-targeted T&D deferral	Value varies by distribution project, 90 MW eligible for deferral by 2030	Same as Base Case
DR technology cost	10% reduction from current levels by 2030 (in real terms)	30% reduction from current levels by 2030 (in real terms)

Notes: Unless otherwise specified, values shown are for year 2030 and in nominal dollars.

Modeling results are summarized for the years 2023 and 2030. 2023 is the year by which NSP must procure additional DR capability according to the Minnesota PUC's Order in Docket No. E-002/RP-15-21. The 2030 snapshot captures the potential for significant future changes in system conditions and their implications for DR value, and is consistent with the longer-term perspective of NSP's IRP study horizon. A summary of annual results, including intermediate years, is provided in Appendix D.

Data

To develop participation, cost, and load impact assumptions for this study, we relied on a broad range of resources. Where applicable, we relied directly upon information from NSP's experience with DR programs in its service territory. We also utilized the results of primary market research that was conducted directly with customers in NSP's service territory in order to better understand their preferences for various DR program options. Where NSP-specific information was unavailable, we reviewed national data on DR programs, DR potential studies from other jurisdictions, and DR program impact evaluations. A complete list of resources is provided in the References section and described further in Appendix A.

In an assessment of emerging DR opportunities, it is important to recognize that data availability varies significantly by DR program type. Conventional DR programs, such as air-conditioning load control, have decades of experience as full-scale deployments around the US and internationally. By contrast, emerging DR programs like EV charging load control have only recently begun to be explored, largely through pilot projects. Figure 4 summarizes data availability for each of the DR program types analyzed in this study.

Figure 4: Data Availability by DR Program Type

	Participation	Costs	Peak Impacts	Advanced Impacts
Residential				
Air-conditioning DLC	●	●	●	N/A
Smart thermostat	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Behavioral DR	◑	◑	◑	N/A
Smart water heating	◔	◔	◑	◔
Timed water heating	◔	◔	◑	◔
EV managed charging (home)	○	○	◔	N/A
EV charging TOU (home)	○	○	◔	N/A
C&I				
Interruptible tariff	●	●	●	N/A
Demand bidding	●	●	●	N/A
TOU rate	●	●	◑	N/A
CPP rate	●	●	◑	N/A
Ice-based thermal storage	◔	◔	◔	◔
EV workplace charging	○	○	◔	N/A
Automated DR	○	◔	◔	○

Notes:

● NSP-specific data, including market research, pilot programs, and full-scale deployments

◑ Signficant program experience in other jurisdictions

◔ Some pilot or demonstration project experience in other jurisdictions

○ Speculative, estimated from theoretical studies and calibrated to NSP conditions

"Advanced impacts" refers to load flexibilty capability beyond conventional peak period reductions (e.g., frequency regulation)

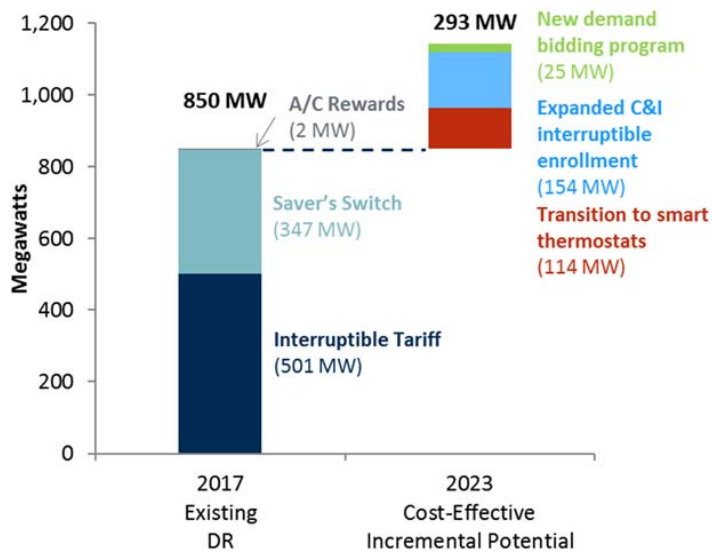
III. Conventional DR Potential in 2023

As an initial step in the assessment of NSP's cost-effective DR potential, we analyzed the potential if NSP were to deploy a portfolio of conventional DR programs. As defined for this study, conventional programs include interruptible tariffs, air-conditioning DLC, smart thermostats, and demand bidding. These program types are currently offered by NSP, with the exception of demand bidding. Therefore, the assessment of conventional programs is largely an assessment of the potential to grow the current DR portfolio through options such as new marketing initiatives or targeted marketing toward specific customer segments. We initially focus on the year 2023, as that is the year by which the Minnesota PUC has required NSP to procure additional DR capability.[10]

Figure 5 summarizes the cost-effective potential in a conventional DR portfolio in 2023. There is 293 MW of cost-effective incremental potential. Drivers of this potential include the expanded enrollment in NSP's interruptible tariff program, greater per-participant impacts that will be achieved as NSP continues to transition from a switch-based air-conditioning DLC program to a smart thermostat-based program, overall growth in NSP's customer base between 2017 and 2023, and a modest amount of potential in a new demand bidding program.

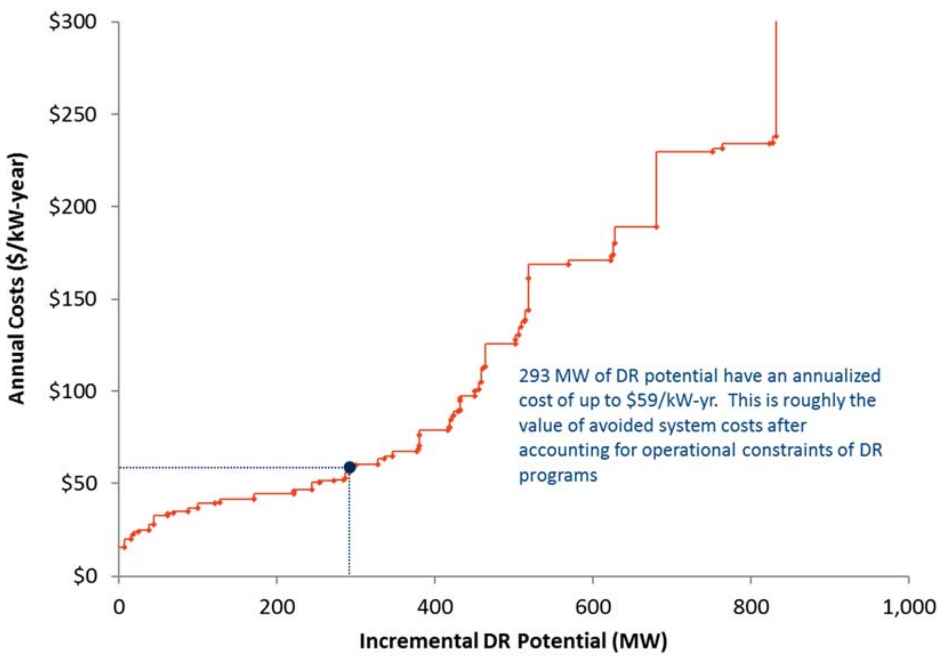
[10] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

Figure 5: Total DR Potential in 2023 (Conventional Portfolio)



The incremental potential in conventional DR programs can be expressed as a "supply curve." Figure 6 illustrates the costs associated with achieving increasing levels of DR capability. The upward slope of the curve illustrates how DR capability (i.e., enrollment) increases as incentive payments increase. The curve also captures the different costs and potential associated with each conventional DR program and applicable customer segment. Cost-effective DR capability is identified with the blue dotted line. There is roughly 293 MW of incremental DR potential available at a cost of less than $59/kW-year. That cost equates to the value of avoided system costs after accounting for the operational constraints of DR programs.

Figure 6: NSP's Incremental DR Supply Curve in 2023 (Conventional Portfolio)



Note: Supply curve shows conventional DR potential without accounting for cost-effectiveness. Potential estimates if the DR options were offered simultaneously as part of a portfolio at each price point (i.e. accounts for overlap). Program costs presented in nominal terms.

As discussed previously in this report, the Minnesota PUC has established a DR procurement requirement of 400 MW by 2023. It is important to clarify whether this 400 MW is a capacity-equivalent value, a generator-level value, or a meter-level value. Specifically, 1 MW of load reduction at the meter (or customer premise) avoids more than 1 MW at the generator level due to line losses between the generator and the customer. Further, 1 MW of load reduction at the generator level provides more than 1 MW of full capacity-equivalent value, as the load reduction would also avoid the additional capacity associated with NSP's obligation to meet the planning reserve requirement. Based on NSP's calculations, which account for line losses and the reserve requirement, 1 MW of load reduction at the meter level equates to 1.08 MW of load reduction at the generator level and 1.11 MW of capacity-equivalent value.

NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR. This equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses. These values are summarized in Table 3. Throughout this report, DR values are reported at the generator level. Thus, for consistency, we refer to the procurement requirement as a 391 MW generator-level value unless otherwise specified.

Table 3: NSP's 2023 DR Procurement Requirement

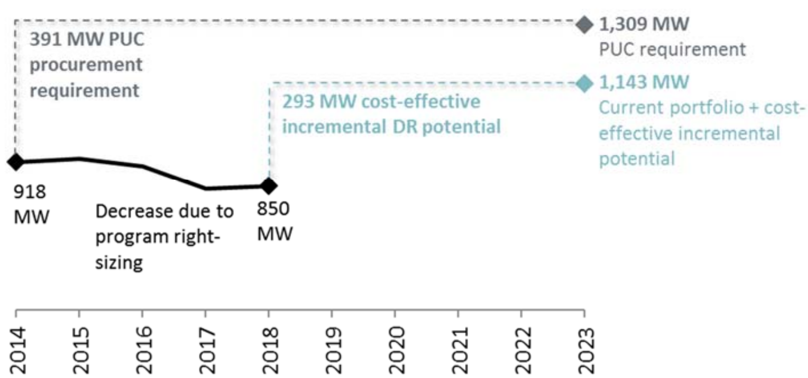
	Requirement (MW)	Notes
Meter level	361.7	Premise-level
Generator level	390.7	Grossed up for 8% line losses
Capacity equivalent	400.0	Grossed up for line losses and reserve requirement

Source: Calculations provided by NSP.

Our interpretation of the PUC's Order is that the required DR procurement is incremental to NSP's DR capability as it existed in 2014.[11] NSP had 918 MW of DR capability in 2014, leading to a total DR capability requirement of 1,309 MW in 2023. NSP's DR capability decreased between 2014 and 2017 largely due to an effort to ensure that enrolled load would be available for curtailment when called upon, thus leading to an incremental DR requirement that is larger than 391 MW (at the generator level).[12]

Combined with current capability of 850 MW, the incremental cost-effective DR potential in 2023 would result in a total portfolio of 1,143 MW. This estimate of cost-effective potential is 166 MW short of the PUC's DR procurement requirement. Figure 7 illustrates the gap between NSP's conventional DR potential and the DR procurement requirement.

Figure 7: NSP DR Capability (Conventional Portfolio)



Note: Chart is scaled such that vertical axis does not start at zero. 391 MW procurement requirement is expressed at the generator level and is equivalent to 400 MW of DR capacity.

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11 2014 is the year of NSP's prior DR potential study, which was used to inform the Minnesota PUC's establishment of the DR procurement requirement.

12 For instance, some customers did not realize that they were participating in the program and dropped out when notified, or otherwise elected to reduce their enrolled load level.

IV. Expanded DR Potential in 2023

Given the shortfall of the conventional DR portfolio relative to the 2023 procurement target, it is relevant to consider if an expanded portfolio of DR options could mitigate the shortfall. We analyzed eight additional emerging DR programs that could be offered to up to four different customer segments (if applicable). As described in Section II, these emerging DR options include both price based programs (e.g., TOU and CPP rate designs) and technology-based programs (e.g., Auto-DR and smart water heating).

Base Case

Among the individual measures with the most *technical potential* in 2023 are HVAC Auto-DR for Medium C&I customers and thermal storage for commercial customers. Each of these programs has technical potential in excess of 100 MW.

Pricing programs and lighting Auto-DR for C&I customers, timed water heating programs, and behavioral DR compose the next tier of opportunities, with technical potential in each ranging between 50 and 100 MW. These programs generally have the potential to reach significant levels of enrollment or, alternatively, to provide deep load reductions among a smaller share of customers.

The Small C&I segment accounts for many of the DR programs with the lowest technical potential, as there is a relatively small share of load in this segment and these customers have historically demonstrated a lower willingness to participate in DR programs.

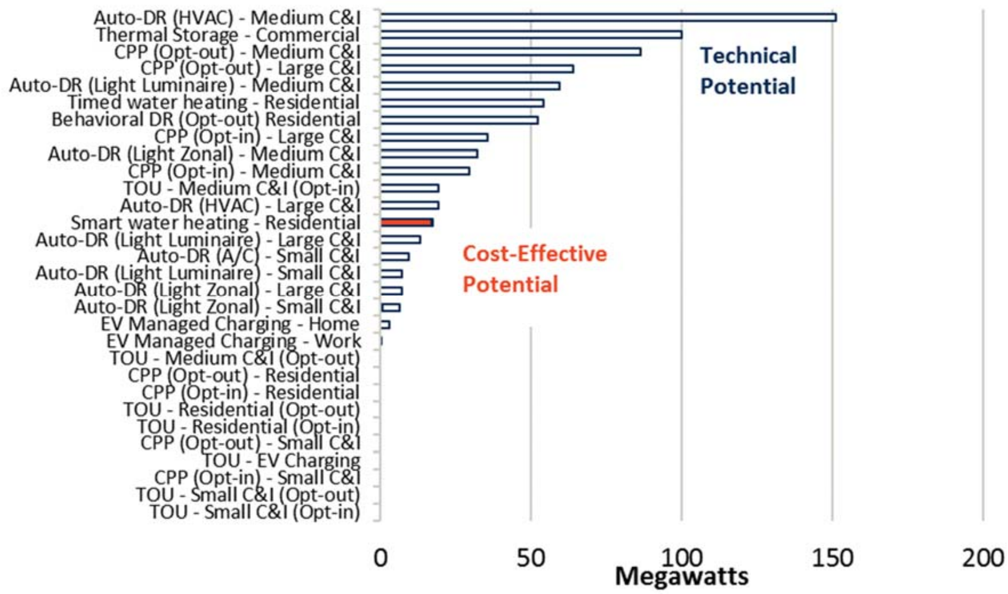
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

Pricing programs (i.e., TOU, CPP) cannot be offered on a full scale basis in 2023 to residential and small C&I customers, as AMI will not yet be fully deployed. Therefore, pricing programs have not been included in the potential estimates for 2023. Rollout of the programs is assumed to begin in 2024, upon NSP's projected completion of the AMI rollout.

Programs with significant *technical potential* do not necessarily have significant *cost-effective potential*. After accounting for cost-effectiveness under Base Case market conditions as well as technical constraints, the potential in DR programs is limited in 2023. Individually, only smart water heating and a modest amount of automated load control for C&I customers pass the cost-effectiveness screen. These programs pass the cost-effectiveness screen largely because they are capable of providing an expanded array of value streams, such as frequency regulation and geo-targeted T&D deferral.

Figure 8 summarizes the technical and cost-effective potential in each of the new DR program options. Potential is first shown for DR programs as if they were each offered in isolation.

Figure 8: New DR Program Potential in 2023 (Base Case)

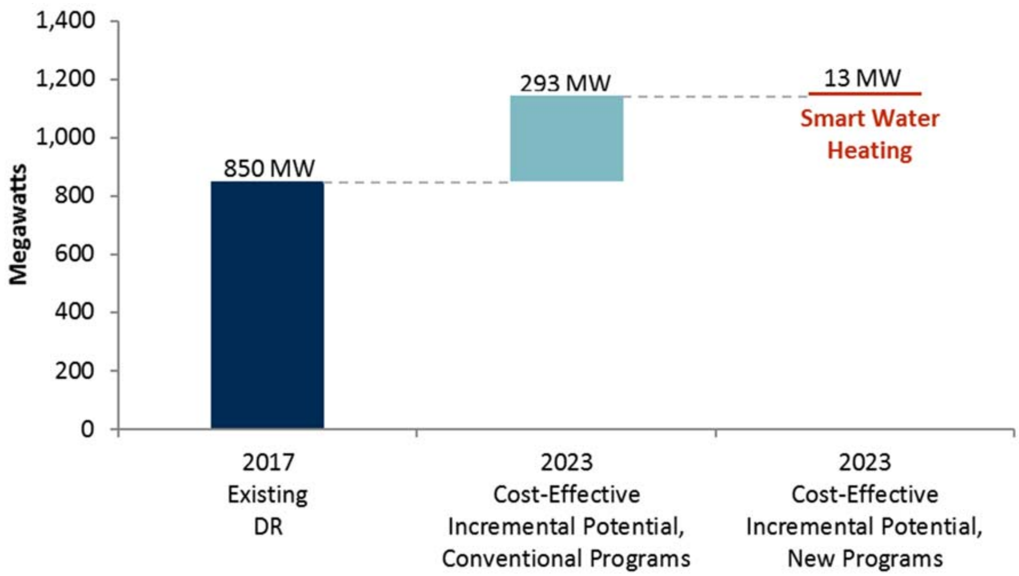


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The program-level DR impacts shown above cannot be added together to arrive at the potential capability of a DR portfolio. Adjustments must be made to account for double-counting of impacts when customers are enrolled in more than one program, and for limits on the need for certain value streams such as frequency regulation. Thus, combining the cost-effective programs into a portfolio can result in lower total potential DR capability than if the individual impacts shown above were simply summed.

In the 2023 scenario described above, the smart water heating program alone could satisfy NSP's need for frequency regulation. With that value stream no longer available to the Auto-DR program, the Auto-DR program fails the cost-effectiveness screen. **With the addition of the smart water heating program, NSP's cost-effective DR portfolio would increase by 13 MW. Achievement of all cost-effective DR potential would amount to total system-wide DR capability of 1,156 MW, but would still fall short of the PUC's procurement target by 154 MW.** The expanded capability in 2023 is illustrated in Figure 9.

Figure 9: Total DR Potential in 2023 (Expanded Portfolio)



Near-term Limitations on DR Value

The value of DR is very dependent on the characteristics of the system in which it is deployed. Several factors limit NSP's cost-effective DR in 2023, relative to other jurisdictions.

- **Low capacity prices:** NSP has access to low-cost peaking capacity, primarily due to the presence of brownfield sites that significantly reduce development costs. For instance, the all-in cost of a new combustion turbine in NSP's IRP is \$63/kW-year, which is 23 percent lower than the cost of a CT assumed by the U.S. Energy Information Administration (EIA) in its Annual Energy Outlook (AEO). Similarly, a recent study approved by the Minnesota PUC determined that the average value of T&D capacity deferral achieved through reductions in customer consumption is approximately \$11/kW-year in NSP's service territory.[13] This value, which was determined through a detailed bottom-up engineering assessment, is significantly lower than that of T&D deferral benefits observed in other studies, which can commonly reach values of \$30/kW-year.[14] The value of T&D deferral is dependent on characteristics of the utility system and drivers of the investment need, and therefore varies significantly across utilities.

13 Xcel Energy, "Minnesota Transmission and Distribution Avoided Cost Study," submitted to the Minnesota Department of Commerce, Division of Energy Resources (Department), July 31, 2017

14 Ryan Hledik and Ahmad Faruqui, "Valuing Demand Response: International Best Practices, Case Studies, and Applications," prepared for EnerNOC, January 2015.

- **Metering technology limitations:** NSP has not yet deployed AMI, with an estimated forecast that system-wide AMI installation will be completed in 2024. AMI-based DR programs, such as time-varying rates and behavioral DR, cannot be offered to customers until deployment is complete. This effectively excludes the possibility of introducing any AMI-based programs in the year 2023.

- **High DR technology costs:** Some emerging DR programs depend on new technologies that have not yet experienced the cost declines that could be achieved at scale. While these technology costs could decrease over time, those reductions are not achieved in the early years of the study horizon.

- **Limited need for additional DR value streams:** While certain DR value streams potentially can be very valuable, these value streams can also be limited in need. For instance, our analysis of NSP's five-year distribution plan identified only 38 MW of projects that were potential candidates for geo-targeted capacity investment deferral. Those projects accounted for roughly 10 percent of the total value of NSP's plan. To qualify, projects need to satisfy criteria such as being driven by growth in demand and being of a certain size.[15] Similarly, while frequency regulation is often a highly-valued ancillary service and can be provided by certain types of DR, the need for frequency regulation across most markets is significantly less than one percent of system peak demand. This limits the amount of that value stream that can be provided by DR.

High Sensitivity Case

The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. As discussed earlier in this report, assumptions behind the High Sensitivity Case are not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

Under the illustrative High Sensitivity Case assumptions, cost-effective DR potential increases significantly. Several programs that were not previously passing the cost-effectiveness screen, such as medium C&I HVAC-based Auto DR, residential timed water heating, and a small amount of lighting-based Auto-DR do pass the screen under the more favorable assumptions in this case. Figure 10 summarizes the increase in cost-effective potential at the individual program level.

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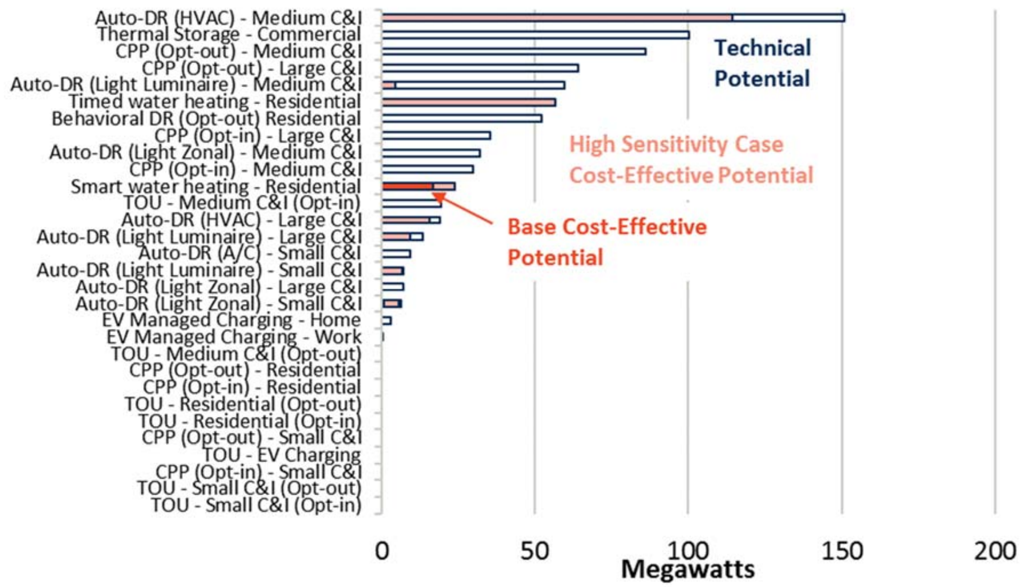
[15] Details of the geo-targeted T&D deferral analysis are included in Appendix A.

Figure 10: New DR Program Potential in 2023 (High Sensitivity Case)



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

A DR portfolio constructed from cost-effective programs in the High Sensitivity Case would produce total incremental DR potential of 484 MW in 2023. Under the illustrative assumptions in this case, the cost-effective incremental portfolio would consist of 393 MW of conventional DR programs, and 91 MW of new DR programs. The portfolio of new DR programs includes residential smart water heating [16] (24 MW) and C&I HVAC-based Auto-DR (67 MW). Achievement of all cost-effective DR potential under the High Sensitivity Case would amount to total system-wide DR capability of 1,334 MW.

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[16] Smart water heating has lower cost-effective potential in 2023 than timed water heating. However, the smart water heating program provides more value and more significant per-participant impacts as participation ramps up in the later years of the study horizon, so it is the water heating program that was included in the portfolio.

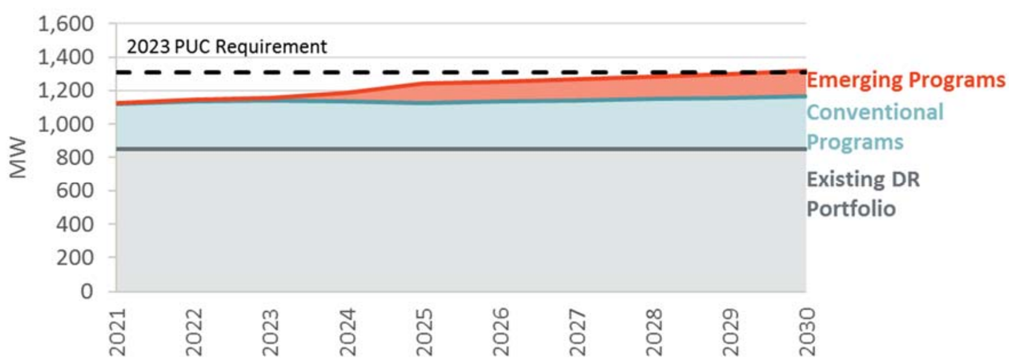
V. Expanded DR Potential in 2030

Base Case

Opportunities to expand cost-effective DR portfolio will grow beyond 2023. Most significantly, time-varying rates (such as TOU and CPP rates) can be offered to customers following completion of the AMI rollout in 2024. Additionally, the customer base is projected to grow over the study horizon, expanding the population of customers eligible to participation in DR programs. Growth in the market penetration of renewable generation will likely lead to more volatility in energy costs, further creating opportunities for DR to provide value. Additionally, current participants in the Savers Switch program are expected to transition to the smart thermostat-based A/C Reward program over time. Smart thermostats provide a greater per-participant demand reduction than the technology in the Savers Switch program, therefore further increasing DR potential.

Figure 11 summarizes growth in DR potential under Base Case assumptions for the portfolio of cost-effective DR programs. The majority of the post-2023 growth comes from the introduction of time-varying pricing programs.

Figure 11: Cost-Effective DR Potential, Base Case



Under Base Case conditions, benefits of the DR program are primarily driven by avoided generation capacity costs. Avoided generation capacity costs account for $51 million of the $66 million (77 percent) in total annual benefits from the DR programs in the year 2030. This is because the relatively low avoided costs in the Base Case scenario tend to favor conventional DR programs which are primarily constrained to reducing the system peak, but have lower costs as a result of this somewhat limited functionality. Table 4 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the Base Case.

Table 4: Annual Avoided Costs from 2030 DR Portfolio, Base Case ($ million/year)

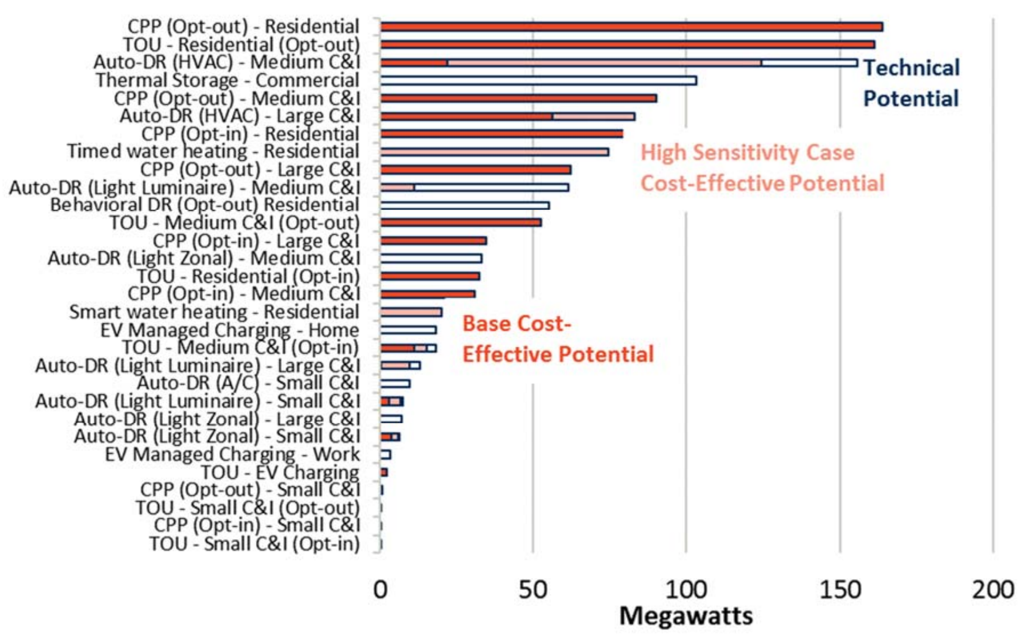
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

Notes: Benefits shown in 2023 dollars.

High Sensitivity Case

Drivers of growth over time under the illustrative High Sensitivity Case conditions are similar to growth drivers under Base Case conditions, with AMI-enabled time-varying rates accounting for the majority of new opportunities after 2023. Figure 12 summarizes the 2030 incremental measure-level potential for both the Base Case and the High Sensitivity Case.

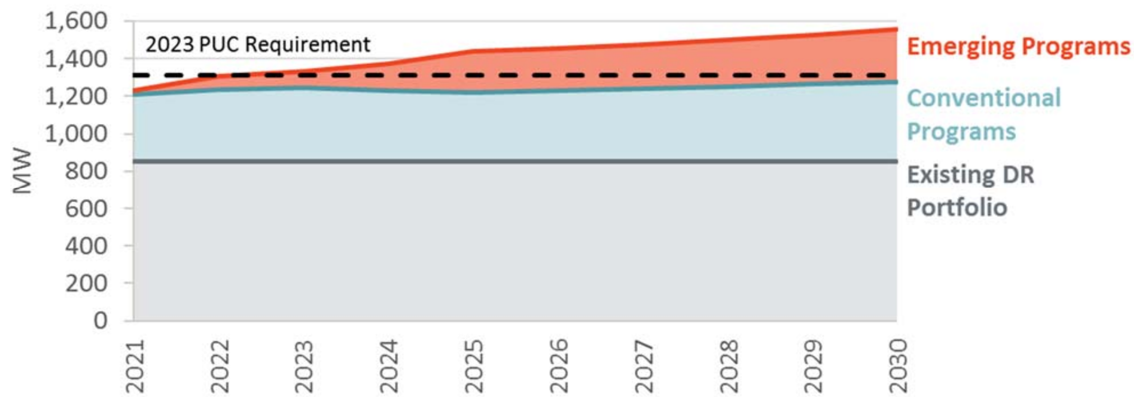
Figure 12: New DR Program Potential in 2030



Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

The capability of the cost-effective DR portfolio for the High Sensitivity Case is summarized in Figure 13.

Figure 13: Cost-Effective DR Potential, High Sensitivity Case



Over the longer-term, new policies could potentially drive down DR costs and therefore increase cost-effective potential. One initiative that has garnered some attention is the development of a technology standard known as "CTA-2045." CTA-2045 is a communications interface which would allow various control technologies to connect to appliances through a standard port or socket. While widespread adoption of this standard is not considered to be imminent, it could potentially have positive implications for DR adoption in the longer term. See the Sidebar at the end of this section for further discussion of the outlook for CTA-2045.

The benefits of DR under the High Sensitivity Case assumptions continue to be driven primarily by avoided generation capacity costs. However, additional price volatility due a greater assumed mix of renewable generation in the regional supply portfolio leads to an increase in the share of total that is attributable to avoided energy costs. The total value of frequency regulation provided by DR also increases modestly relative to the Base Case, as a greater need for this service is assumed for renewable generation integration purposes. Table 5 summarizes the annual benefits, by category, of the incremental cost-effective DR portfolio in 2030 for the High Sensitivity Case.

Table 5: Annual Avoided Costs from 2030 DR Portfolio, High Sensitivity Case ($ million/year)

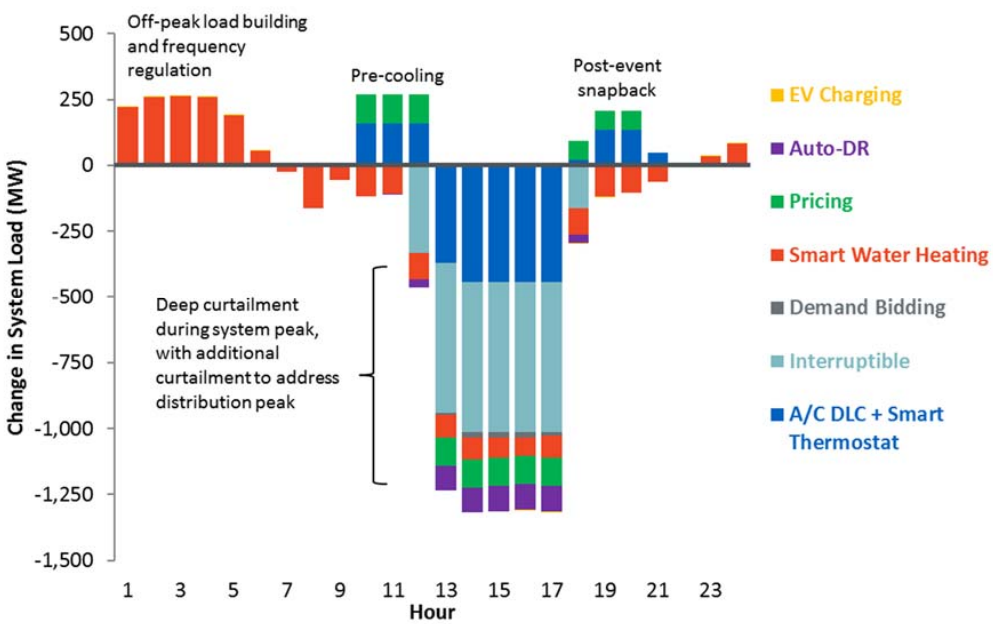
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

Notes: Benefits shown in 2023 dollars.

DR Portfolio Operation

The addition of emerging programs to NSP's DR portfolio will improve operational flexibility across NSP's system. Figure 14 illustrates how the cost-effective DR portfolio from the High Sensitivity Case could operate on an hourly basis during the days of the year with the highest system peak demand. The profile shown maximizes avoided costs relative to the system cost assumptions used in this study.

Figure 14: Average Load Impacts of the 2030 Cost-Effective DR Portfolio on Top 10 Load Days (High Sensitivity Case)



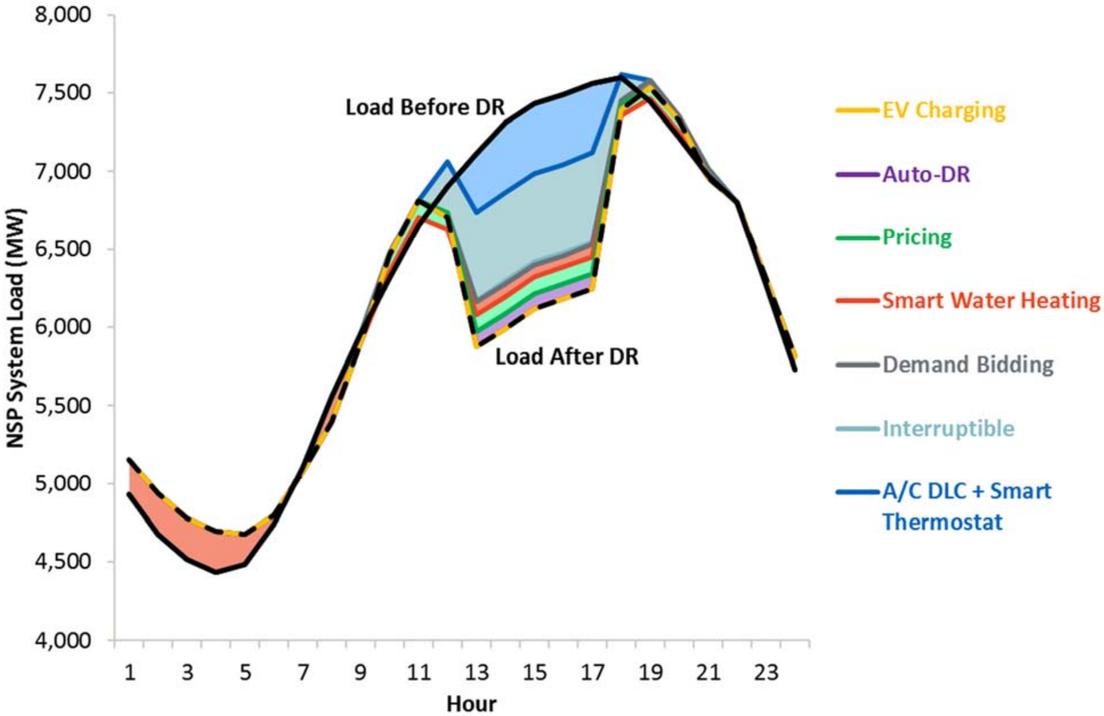
Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

A deep curtailment of load during system peak hours is utilized to capture significant generation and T&D capacity deferral benefits. These also tend to be hours when energy costs are highest, leading to additional energy value. The duration of the peak load curtailment spans a fairly broad period of time – seven hours – in order to account for the lack of coincidence of the system and local peak demand that drive capacity needs. Load curtailment can be staggered across DR programs – and across participants in a given DR program – in order to achieve this duration of demand reduction.

Load increases are observed immediately before and after the peak load reduction. This is driven mostly by the need to maintain and restore building temperatures to desired levels around DR events. The smart water heating program builds load during nighttime hours, shifting heating load to the lowest cost hours and potentially reducing the curtailment of renewable generation.

Figure 15 illustrates how NSP's system load shape changes as a result of the impacts shown in Figure 14 above. The figure shows a steep reduction in load during hours of the MISO system peak, while NSP's later peak is only modestly reduced. This is primarily due to NSP's planning needs being driven by MISO coincident peak demand. If the MISO peak shifts later in the day due to solar PV adoption, or if NSP transitions to an increased focus on its own peak demand in planning activities, then the dispatch of the DR programs would need to be modified accordingly. In particular, it may become necessary to stagger the utilization of DR programs across a broader window of hours in order to "flatten" peak demand across the hours of the day.

Figure 15: Average Impacts of the 2030 Cost-Effective DR Portfolio on NSP System Load (High Sensitivity Case)



Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

Sidebar: The Outlook for CTA-2045

CTA-2045 is a standard which specifies a low-cost communications "socket" that would be embedded in electric appliances and other consumer products. If consumers wished to make an appliance capable of participating in a demand response program, they could simply plug a communications receiver into the socket, thus allowing the appliance to be controlled by themselves or a third party. CTA-2045 has the potential to establish a low-cost option for two-way communications capability in appliances, thus reducing the cost and hassle of consumer enrollment in DR programs that would otherwise require on-site installation of more costly equipment.

Development of CTA-2045 began in 2011, through work by the Consumer Technology Association (CTA) and the Electric Power Research Institute (EPRI). Refinements to the standard are ongoing. To assess the outlook for CTA-2045 and its potential implications for future DR efforts, we conducted phone and email interviews with subject matter experts from utilities, appliance manufacturers, and DR software platforms.

There is a shared view that CTA-2045 is facing a chicken-and-egg problem. Manufacturers have been hesitant to incorporate the standard into their products, because there is a cost associated with doing so and they have not yet observed demand in the market for the communications functionality. At the same time, a barrier preventing increased adoption of DR technologies could be some of the costs and installation challenges that CTA-2045 would ultimately address.

Products with CTA-2045 functionality have not yet been deployed at scale, and where available are sold at a price premium that is significantly higher than the unit costs that could ultimately be achieved at scale. The relative lack of enthusiasm among manufacturers for rolling out CTA-2045 compliant products has led to a slow pace of development of the standard itself. Progress is being made incrementally, though technical issues still remain to be resolved.

Looking forward, some in the industry feel that the mandating CTA-2045 through a new state appliance standard could be the catalyst that is needed for adoption to become broadly widespread. Aggressive support for CTA-2045 by large utilities is also considered to be the type of activity that would facilitate adoption.

If compliance with CTA-2045 ultimately were to accelerate through activities like those described above, electric water heaters are poised to become the first such commercial application, as they have been the most common test case for proving the technical concept and are an attractive source of load flexibility. Particularly in the context of water heaters, CTA-2045 would help to overcome the challenge of enrolling customers in a DR program during the very narrow window of time during which their existing water heater expires and must be replaced. Other controllable end-uses, such as thermostats or even electric vehicle chargers could be candidates for the standard, though these technologies sometimes already come pre-equipped with communications capabilities.

VI. Conclusions and Recommendations

NSP's sizeable existing DR portfolio has the potential to be expanded by tapping into latent demand for existing programs and also by rolling out a new portfolio of emerging DR programs. Specific recommendations for acting on the findings of this study including the following:

Aggressively pursue the transition to smart thermostats as well as recruitment of medium C&I customers into the Interruptible program. NSP's relatively low avoided costs mean that lower cost, established DR programs are the most economically attractive options in the near term. Smart thermostats and a Medium C&I interruptible program present the largest incremental opportunity and the least amount of uncertainty/risk.

Pilot and deploy a smart water heating program. There is significant experience with advanced water heating load control in the Upper Midwest, and the technology is rapidly advancing. The thermal storage capabilities of water heaters provide a high degree of load flexibility that can be adapted to a range of system needs.

As a complementary activity to the development of a smart water heating program, also evaluate the economics and environmental impacts of switching from gas to electric heating, factoring in the grid reliability benefits associated with this flexible source of load. Doing so would require revisiting existing state policies that prohibit utility-incentivized fuel switching.

Build the foundation for a robust offering of time-varying rates. As a first step, prepare a strategy for rolling out innovative rates soon after AMI is deployed. This should include exploring rate offerings that could be deployed to customers on a default (opt-out) basis, as default rate offerings maximize the overall economic benefit for the program.

Develop measurement & verification (M&V) 2.0 protocols to ensure that the impacts of the program are dependable and can be integrated meaningfully into resource planning efforts. Included in this initiative could be the development of a data collection plan to enhance the quality of future market potential studies. Further, detailed customer segmentation and geographically granular load data at the distribution system level will provide an improved base from which to develop a cost-effective DR strategy.

Design programs with peak period flexibility. From a planning standpoint, the timing of the peak period could change for a variety of reasons (e.g., DR flattens the peak, solar PV shifts the net peak, or the planning emphasis shifts from a focus on the MISO peak to a focus on more local peaks). DR programs will need to be designed with the flexibility to adjust the timing of curtailments in response to these changes.

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Appendix A: Load*Flex* Modeling Methodology and Assumptions

The Load*Flex* Model

The Brattle Group's Load*Flex* model was developed to quantify the potential impacts, costs, and benefits of demand response (DR) programs. The Load*Flex* modeling approach offers the flexibility to accurately estimate the broader range of benefits that are being offered by emerging "DR 2.0" programs which not only reduce system peak demand, but also provide around-the-clock load management opportunities.

The Load*Flex* modeling framework builds upon the standard approach to quantifying DR potential that has been used in prior studies around the U.S. and internationally, but incorporates a number of differentiating features which allow for a more robust evaluation of DR programs:

- **Economically optimized enrollment:** Assumed participation in DR programs is tailored to the incentive payment levels that are cost-effective for the DR program. If only a modest incentive payment can be justified in order to maintain a benefit-cost ratio of 1.0, then the participation rate is calibrated to be lower than if a more lucrative incentive payment were offered. Prior approaches to quantifying DR potential ignore this relationship between incentive payment level and participation, which tends to under-state the potential (and, in some cases, incorrectly concludes that a DR program would not pass the cost-effectiveness screen).

- **Utility-calibrated load impacts:** Load impacts are calibrated to the characteristics of the utility's customer base. In the residential sector, this includes accounting for the market saturation of various end-use appliances (e.g., central air-conditioning, electric water heating). In the commercial and industrial (C&I) sector, this includes accounting for customer segmentation based on size (i.e., the customer's maximum demand) and industry (e.g., hospital, university). Load curtailment capability is further calibrated to the utility's experience with DR programs (e.g., impacts from existing DLC programs or dynamic pricing pilots).

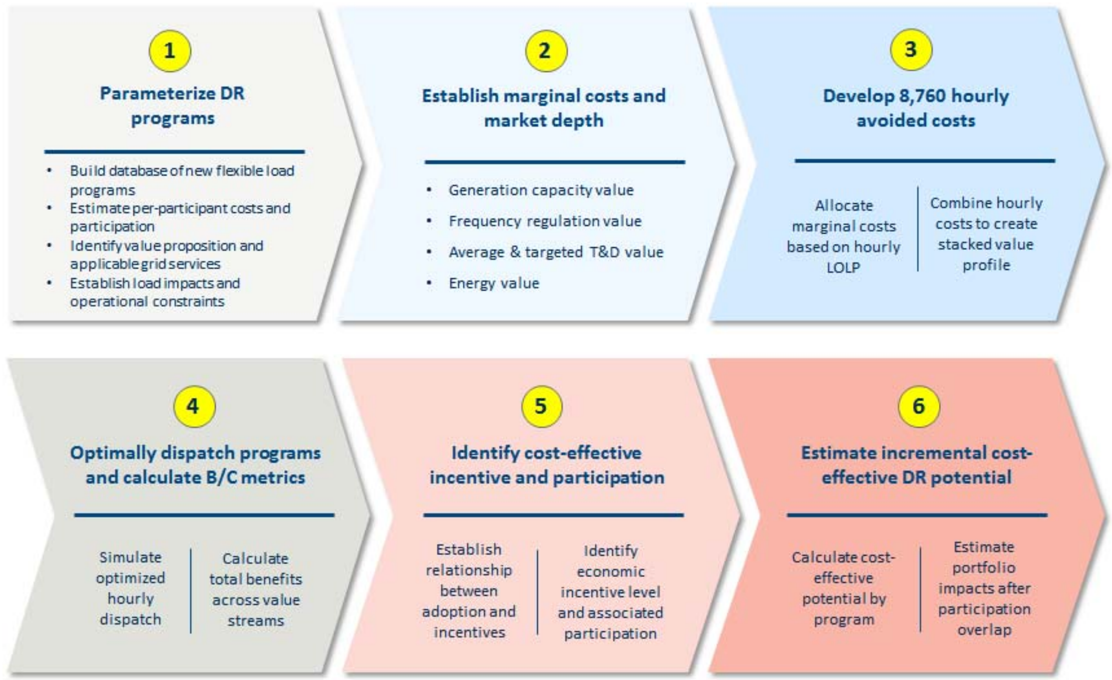
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes an hourly profile of load interruption capability for each program. For instance, for an EV home charging load control program, the model accounts for home charging patterns, which would provide greater average load reduction opportunities during evening hours (when EV owners have returned home from work) than in the middle of the day.

- **Realistic accounting for "value stacking":** DR programs have the potential to simultaneously provide multiple benefits. For instance, a DR program that is dispatched to reduce the system peak and therefore avoid generation capacity costs could also be dispatched to address local distribution system constraints. However, tradeoffs must be made in pursuing these value streams – curtailing load during certain hours of the day may prohibit that same load from being curtailed again later in the day for a different purpose. Load*Flex* accounts for these tradeoffs in its DR dispatch algorithm. DR program operations are simulated to maximize total benefits across multiple value streams, while recognizing the operational constraints of the program. Prior studies have often assigned multiple benefits to DR programs without accounting for these tradeoffs, thus double-counting benefits.

- **Industry-validated program costs:** DR program costs are based on a detailed review of the utility's current DR offerings. For new programs, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors. Program costs are differentiated by type (e.g., equipment/installation, administrative) and structure (e.g., one-time investment, ongoing annual fee, per-kilowatt fee) to facilitate integration into utility resource planning models.

The Load*Flex* methodology is organized around six steps, as summarized in Figure 16. The remainder of this appendix describes each of the six steps in further detail, documenting methodology, assumptions, and data sources.

Figure 16: The Load*Flex* Modeling Framework



Step 1: Parameterize the DR programs

Each DR program is represented according to two broad categories of characteristics: Performance characteristics and cost characteristics.

Program Performance Characteristics

The performance characteristics of each DR program are represented in detail in Load*Flex* to accurately estimate the ability of the DR programs to provide system value. The following are key aspects of each program's performance capability.

Load impact profiles

Each DR program is represented with 24-hour average daily profiles of load reduction and load increase capability. These 24-hour impact profiles are differentiated by season (summer, winter, shoulder) and day type (weekday, weekend). For instance, air-conditioning load curtailment capability is highest during daytime hours in the summer, lower during nighttime summer hours, and non-existent during all hours in the winter.

Whenever possible, load impacts are derived directly from NSP's experience with its existing DR programs and pilots. NSP's experience directly informed the impact estimates for direct load control, smart thermostat, and interruptible rates programs. For emerging non-pricing DR programs, impacts are based on a review of experience and studies in other jurisdictions and tailored to NSP's customer mix and climate. Methods used to develop impact profile estimates for emerging non-pricing DR programs include the following:

- *C&I Auto-DR:* The potential for C&I customers to provide around-the-clock load flexibility was primarily derived from data supporting a 2017 statewide assessment of DR potential in California[17], a 2013 LBNL study of DR capability[18], and electricity load patterns representative of C&I buildings in Minneapolis developed by the Department of Energy.[19] Customer segment-specific estimates from these studies were combined to produce a composite load impact profile for the NSP service territory based on assumptions about NSP's mix of C&I customers. Impacts were scaled as necessary for consistency with NSP's prior experience with C&I DR programs.

- *Water heating load control:* Assumptions for the water heating load control programs – both grid interactive water heating and static timed water heating - are derived from a 2016 study on the value of various water heating load control strategies.[20] The program definition assumes that only customers with existing electric resistance water heaters will be eligible for participating in the water heating programs.

- *Behavioral DR:* Impacts are derived from a review of the findings of behavioral DR pilot studies conducted around the US, including for Baltimore Gas & Electric, Consumers Energy, Green Mountain Power, Glendale Water and Power, Portland Gas Electric, and Pacific Gas and Electric. Most behavioral DR pilot studies have been conducted by Oracle (OPower) and have generally found that programs with a limited number of short curtailment events (4-10 events for 3-5 afternoon/evening hours) can achieve 2% to 3% load reduction across enrolled customers.[21] Based on these findings, we assumed that a

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17 Peter Alstone et al., Lawrence Berkeley National Laboratory, "Final Report on Phase 2 Results: 2025 California Demand Response Potential Study." March 2017.

18 Daniel J. Olsen, Nance Matson, Michael D. Sohn, Cody Rose, Junqiao Dudley, Sasank Goli, and Sila Kiliccote (Lawrence Berkeley National Oaboratory), Marissa Hummon, David Palchak, Paul Denholm, and Jennie Jorgenson (National Renewable Energy Laboratory), and Ookie Ma (U.S. Department of Energy), "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.

19 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

20 Ryan Hledik, Judy Chang, and Roger Lueken. "The Hidden Battery: Opportunities in Electric Water Heating." January 2016. Posted at: http://www.electric.coop/wp-content/uploads/2016/07/The-Hidden-Battery-01-25-2016.pdf

21 For example, see Jonathan Cook et al., "Behavioral Demand Response Study – Load Impact Evaluation Report", January 11, 2016, prepared for Pacific Gas & Electric Company, available at: http://www.oracle.com/us/industries/utilities/behavioral-demand-response-3628982.pdf, and OPower,

Continued on next page

behavioral DR program called 10 times per year between 3 pm and 6 pm would achieve a 2.5% load reduction.

- *EV managed charging:* Estimates of load curtailment capability are based on projections of aggregate EV charging load shapes provided by Xcel Energy. The ability to curtail this charging load is based on a review of recent utility EV charging DR pilots, including managed charging programs at several California utilities (PG&E, SDG&E, SCE, and SMUD) and United Energy in Australia.[22]

- *Ice-based thermal energy storage:* Estimates of load curtailment capability are estimated based on charging and discharging (freezing and cooling) information from Ice Bear[23] and adapted to mirror building use patterns in Minnesota based on load profiles from the U.S. Department of Energy.[24]

For impacts from pricing programs, we relied on Brattle's database of time-varying pricing offerings. The database includes the results of more than 300 experimental and non-experimental pricing treatments across over 60 pilot programs.[25] It includes published results from Xcel Energy's various pricing pilots during this time period. The results of the pilots in the database are used to establish a relationship between the peak-to-off-peak price ratio of the rates and the average load reduction per participant, in order to simulate price response associated with any given rate design. This relationship between load reduction and price ratio is illustrated in Figure 17.

Continued from previous page

"Transform Every Customer into a Demand Response Resource: How Utilities Can Unlock the Full Potential of Residential Demand Response", 2014, available at: https://go.oracle.com/LP=42838?elqCampaignId=74613.

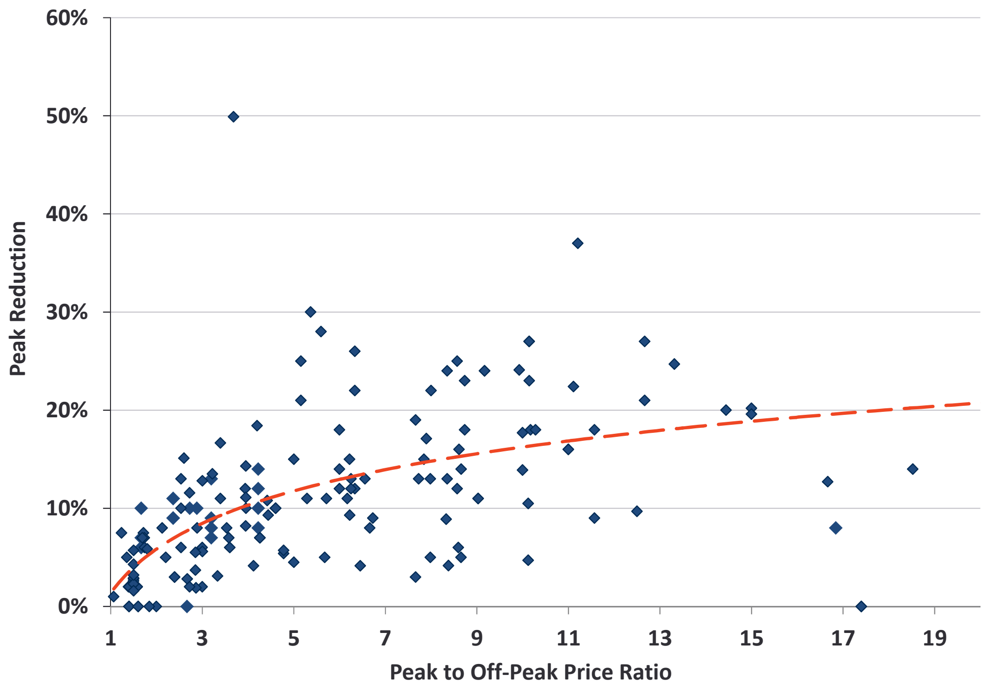
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

23 Ice Energy, "Ice Bear 20 Case Study," November 2016. Available: https://www.ice-energy.com/wp-content/uploads/2016/12/SantaYnez_CaseStudy_Nov2016.pdf

24 See U.S. Department of Energy Commercial Reference Buildings at: https://www.energy.gov/eere/buildings/commercial-reference-buildings

25 Ahmad Faruqui, Sanem Sergici, and Cody Warner, "Arcturus 2.0: A Meta-Analysis of Time-Varying Rates for Electricity," *The Electricity Journal*, 2017.

Figure 17: Relationship between Price Ratio and Price Response in Residential Pricing Pilots



Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

Daily relationship between load reduction and load increase

Some DR programs will require a load increase to offset or partially offset the load that is reduced during a curtailment event. In Load*Flex*, each program definition includes a parameter that represents the percent of curtailed load that must be offset by increased load on the same day, including the timing of when the load increase must occur. For instance, in a water heating load control program, any reduction in water heating load is assumed to be offset by an equal increase in water heating load on the same day in order to meet the customer's water heating needs. Alternatively, a reduction in air-conditioning load may only be offset partially by an increase in consumption, but it would immediately follow the curtailment.

Where data is available, these load building assumptions are based on the same data sources described above. Otherwise, these impacts are derived from assumptions that were developed for FERC's 2009 *A National Assessment of Demand Response Potential*.

Tariff-related operational constraints

Most DR programs will have administrator-defined limits on the operation of the program. This includes the maximum number of hours per day that the program can be curtailed, whether or not those curtailment hours must be contiguous, and the maximum number of days per year with allowed curtailment. Assumed operational constraints are based on Xcel Energy's program definitions and a review of common limitations from programs offered in other jurisdictions.

Ancillary services availability

If a DR program has the advanced control and communications technology necessary to provide ancillary services, Load*Flex* accounts for the capacity that is available to provide fast-response load increases or decreases in response to real-time fluctuations in supply and demand. In this study, smart water heating and Auto-DR are assumed to be able to offer ancillary services. Specifically, we model frequency regulation as it is the most valuable ancillary services product. Capability is based on the same data sources described above.

Table 6 summarizes the performance characteristics for each DR program in this study. In the table, "load shifting capability" identifies whether or not a program is capable of shifting energy usage from peak periods to off-peak periods on a daily basis.

Table 6: DR Program Performance Characteristics

Segment	Program	Peak-coincident curtailment capability (kW/participant)	Hours of Curtailment (hours)	Average regulation up provided (kW/participant)	Average regulation down provided (kW/participant)	Load shifting capability?
Residential	A/C DLC - SFH	0.62	75	0.00	0.00	No
Residential	Behavioral DR (Opt-out)	0.06	40	0.00	0.00	No
Residential	CPP (Opt-in)	0.34	75	0.00	0.00	No
Residential	CPP (Opt-out)	0.17	75	0.00	0.00	No
Residential	EV Managed Charging - Home	0.46	45	0.00	0.00	Yes
Residential	EV Managed Charging - Work	0.09	45	0.00	0.00	Yes
Residential	Smart thermostat - MDU	0.86	75	0.00	0.00	No
Residential	Smart thermostat - SFH	1.15	75	0.00	0.00	No
Residential	Smart water heating	0.46	4,745	0.37	0.38	Yes
Residential	Timed water heating	0.43	1,825	0.00	0.00	Yes
Residential	TOU - EV Charging (Opt-in)	0.05	1,460	0.00	0.00	Yes
Residential	TOU (Opt-in)	0.17	1,284	0.00	0.00	No
Residential	TOU (Opt-out)	0.08	1,284	0.00	0.00	No
Small C&I	A/C DLC	1.93	75	0.00	0.00	No
Small C&I	Auto-DR (A/C)	1.37	200	0.37	0.49	Yes
Small C&I	Auto-DR (Light Luminaire)	1.07	300	0.52	0.57	Yes
Small C&I	Auto-DR (Light Zonal)	0.92	300	0.44	0.49	Yes
Small C&I	CPP (Opt-in)	0.02	75	0.00	0.00	No
Small C&I	CPP (Opt-out)	0.01	75	0.00	0.00	No
Small C&I	Demand Bidding	0.02	200	0.00	0.00	No
Small C&I	Interruptible	1.98	90	0.00	0.00	No
Small C&I	TOU (Opt-in)	0.01	1,281	0.00	0.00	No
Small C&I	TOU (Opt-out)	0.00	1,281	0.00	0.00	No
Medium C&I	A/C DLC	3.92	75	0.00	0.00	No
Medium C&I	Auto-DR (HVAC)	46.17	430	14.61	14.09	Yes
Medium C&I	Auto-DR (Light Luminaire)	18.22	300	8.62	8.83	Yes
Medium C&I	Auto-DR (Light Zonal)	9.81	300	5.47	5.78	Yes
Medium C&I	CPP (Opt-in)	4.83	75	0.00	0.00	No
Medium C&I	CPP (Opt-out)	2.42	75	0.00	0.00	No
Medium C&I	Demand Bidding	4.43	200	0.00	0.00	No
Medium C&I	Interruptible	27.45	90	0.00	0.00	No
Medium C&I	Thermal Storage	50.97	644	0.00	0.00	Yes
Medium C&I	TOU (Opt-in)	2.31	1,281	0.00	0.00	No
Medium C&I	TOU (Opt-out)	1.39	1,281	0.00	0.00	No
Large C&I	Auto-DR (HVAC)	592.09	430	151.57	207.60	Yes
Large C&I	Auto-DR (Light Luminaire)	416.95	120	191.67	200.74	Yes
Large C&I	Auto-DR (Light Zonal)	224.51	120	103.21	108.09	Yes
Large C&I	CPP (Opt-in)	283.92	75	0.00	0.00	No
Large C&I	CPP (Opt-out)	141.67	75	0.00	0.00	No
Large C&I	Demand Bidding	260.28	200	0.00	0.00	No
Large C&I	Interruptible	483.62	90	0.00	0.00	No

Notes:
Program impacts shown reflect impacts for new participants. Impacts shown assume each program is offered independently.

Program Cost Characteristics

The costs of each program include startup costs, marketing and customer recruitment, the utility's share of equipment and installation costs, program administration and overhead, churn costs (i.e., the annual cost of replacing participants that leave the program), and participation incentives.[26]

26 The Utility Cost Test (UCT) is the cost-effectiveness screen used in this study, which calls for including incentive payments as a cost.

Cost assumptions are based on NSP's current program costs, where applicable. Otherwise, costs are based on a review of experience and studies in other jurisdictions and conversations with vendors, and are tailored for consistency with NSP's current program costs. Notable assumptions in developing the cost estimates include the following:

- Water heating technology costs include the cost of the load control and communications equipment and the *incremental* cost of replacing the existing water heater (50-gallon average) with a larger water heater (80-gallon) when the existing water heater expires. The full cost of a new water heater is not assigned to the program.

- Similarly, EV charging load control equipment costs include the incremental cost of load control and communications technology, but not the full cost of a charging unit.

- The cost of AMI is not counted against any of the DR programs, as it is treated as a sunk cost that is likely to be justified by a broad range of benefits that the new digital infrastructure will provides to customers and to NSP. However, a rough estimate of the cost of IT and billing system upgrades specifically associated with offering time-varying pricing programs are included in the costs for those programs.

- The cost of advanced lighting control systems is not counted against DR programs as these control systems are typically installed for non-energy benefits.

Table 7 summarizes Base Case cost assumptions for 2023 and Table 8 summarizes High Sensitivity Case cost assumptions for 2030. The 2030 assumptions reflect an assumed 25% reduction in the cost (in real terms) of emerging technologies. Costs in both tables are shown in nominal dollars. As discussed later in this appendix, the "base" incentive levels are derived from commonly observed payments both by NSP and in other jurisdictions. They do not reflect the cost-effective incentive payment levels that are ultimately established through the modeling.

Table 7: 2023 Base Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/participant-year)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$172	$92	$0	$13	$59	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$4	$0	15
Residential	CPP (Opt-in)	$223,208	$0	$80	$83,703	$2	$0	15
Residential	CPP (Opt-out)	$223,208	$0	$40	$83,703	$2	$0	15
Residential	EV Managed Charging - Home	$0	$229	$0	$0	$17	$45	15
Residential	EV Managed Charging - Work	$0	$229	$0	$0	$17	$45	15
Residential	Smart thermostat - MDU	$0	$126	$92	$0	$11	$28	10
Residential	Smart thermostat - SFH	$0	$126	$92	$0	$11	$28	10
Residential	Smart water heating	$0	$686	$34	$0	$0	$28	10
Residential	Timed water heating	$0	$458	$34	$0	$0	$11	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$83,703	$0	$0	15
Residential	TOU (Opt-in)	$223,208	$0	$57	$83,703	$1	$0	15
Residential	TOU (Opt-out)	$223,208	$0	$29	$83,703	$0	$0	15
Small C&I	A/C DLC	$0	$172	$92	$0	$13	$237	15
Small C&I	Auto-DR (A/C)	$0	$0	$2,218	$0	$22	$112	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,328	$0	$22	$112	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$1,001	$0	$22	$112	15
Small C&I	CPP (Opt-in)	$74,403	$0	$80	$27,901	$0	$0	15
Small C&I	CPP (Opt-out)	$74,403	$0	$40	$27,901	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$691,944	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$280,126	$0	$259	15
Small C&I	TOU (Opt-in)	$74,403	$0	$57	$20,926	$0	$0	15
Small C&I	TOU (Opt-out)	$74,403	$0	$29	$20,926	$0	$0	15
Medium C&I	A/C DLC	$0	$343	$92	$0	$13	$481	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$26,820	$0	$22	$9,444	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$33,220	$0	$22	$4,351	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$24,719	$0	$22	$4,351	15
Medium C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Medium C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$280,126	$0	$249	15
Medium C&I	Interruptible	$0	$0	$0	$280,126	$0	$5,627	15
Medium C&I	Thermal Storage	$0	$120,114	$34	$0	$382	$0	20
Medium C&I	TOU (Opt-in)	$74,403	$0	$1,144	$20,926	$22	$0	15
Medium C&I	TOU (Opt-out)	$74,403	$0	$572	$20,926	$22	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$306,980	$0	$22	$108,307	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$495,047	$0	$22	$86,691	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$367,510	$0	$22	$86,691	15
Large C&I	CPP (Opt-in)	$74,403	$0	$1,144	$27,901	$22	$0	15
Large C&I	CPP (Opt-out)	$74,403	$0	$572	$27,901	$22	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$315,839	$0	$14,651	15
Large C&I	Interruptible	$0	$0	$0	$315,839	$0	$90,997	15

Notes:

All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Table 8: 2030 High Sensitivity Case Program Cost Assumptions

		One-Time Costs			Recurring Costs			
Segment	Program	Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Fixed Admin & Other ($/year)	Variable Admin & Other ($/participant-year)	Base Annual Incentive Level ($/part.-yr)	Economic Life (years)
Residential	A/C DLC - SFH	$0	$140	$75	$0	$16	$69	15
Residential	Behavioral DR (Opt-out)	$0	$0	$0	$0	$5	$0	15
Residential	CPP (Opt-in)	$182,204	$0	$65	$97,609	$2	$0	15
Residential	CPP (Opt-out)	$182,204	$0	$33	$97,609	$2	$0	15
Residential	EV Managed Charging - Home	$0	$187	$0	$0	$20	$52	15
Residential	EV Managed Charging - Work	$0	$187	$0	$0	$20	$52	15
Residential	Smart thermostat - MDU	$0	$103	$75	$0	$13	$33	10
Residential	Smart thermostat - SFH	$0	$103	$75	$0	$13	$33	10
Residential	Smart water heating	$0	$560	$28	$0	$0	$33	10
Residential	Timed water heating	$0	$374	$28	$0	$0	$13	10
Residential	TOU - EV Charging (Opt-in)	$0	$0	$0	$97,609	$0	$0	15
Residential	TOU (Opt-in)	$182,204	$0	$47	$97,609	$1	$0	15
Residential	TOU (Opt-out)	$182,204	$0	$23	$97,609	$1	$0	15
Small C&I	A/C DLC	$0	$140	$75	$0	$16	$277	15
Small C&I	Auto-DR (A/C)	$0	$0	$1,810	$0	$26	$130	15
Small C&I	Auto-DR (Light Luminaire)	$0	$0	$1,084	$0	$26	$130	15
Small C&I	Auto-DR (Light Zonal)	$0	$0	$817	$0	$26	$130	15
Small C&I	CPP (Opt-in)	$60,735	$0	$65	$32,536	$0	$0	15
Small C&I	CPP (Opt-out)	$60,735	$0	$33	$32,536	$0	$0	15
Small C&I	Demand Bidding	$0	$0	$0	$806,905	$0	$1	15
Small C&I	Interruptible	$0	$0	$0	$326,666	$0	$302	15
Small C&I	TOU (Opt-in)	$60,735	$0	$47	$24,402	$0	$0	15
Small C&I	TOU (Opt-out)	$60,735	$0	$23	$24,402	$0	$0	15
Medium C&I	A/C DLC	$0	$280	$75	$0	$16	$561	15
Medium C&I	Auto-DR (HVAC)	$0	$0	$21,893	$0	$26	$11,013	12
Medium C&I	Auto-DR (Light Luminaire)	$0	$0	$27,117	$0	$26	$5,074	15
Medium C&I	Auto-DR (Light Zonal)	$0	$0	$20,178	$0	$26	$5,074	15
Medium C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Medium C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Medium C&I	Demand Bidding	$0	$0	$0	$326,666	$0	$291	15
Medium C&I	Interruptible	$0	$0	$0	$326,666	$0	$6,562	15
Medium C&I	Thermal Storage	$0	$98,049	$28	$0	$445	$0	20
Medium C&I	TOU (Opt-in)	$60,735	$0	$934	$24,402	$26	$0	15
Medium C&I	TOU (Opt-out)	$60,735	$0	$467	$24,402	$26	$0	15
Large C&I	Auto-DR (HVAC)	$0	$0	$250,588	$0	$26	$126,301	12
Large C&I	Auto-DR (Light Luminaire)	$0	$0	$404,107	$0	$26	$101,093	15
Large C&I	Auto-DR (Light Zonal)	$0	$0	$299,998	$0	$26	$101,093	15
Large C&I	CPP (Opt-in)	$60,735	$0	$934	$32,536	$26	$0	15
Large C&I	CPP (Opt-out)	$60,735	$0	$467	$32,536	$26	$0	15
Large C&I	Demand Bidding	$0	$0	$0	$368,313	$0	$17,085	15
Large C&I	Interruptible	$0	$0	$0	$368,313	$0	$106,116	15

Notes:
2030 one-time costs assumed to be 30% lower than 2023 one-time costs (in real terms), reflecting assumed declines in technology costs. All costs shown in nominal dollars. Variable equipment cost and other initial costs include 2.5% churn cost adder. Analysis assumes a 6.44% discount rate for annualizing one-time costs.

Step 2: Establish system marginal costs and quantity of system need

Load*Flex* was used to quantify a broad range of value streams that could be provided by DR. These include avoided generation capacity costs, avoided system-wide T&D costs, additional avoided distribution costs from geo-targeted deployment of the DR programs, frequency regulation, and net avoided marginal energy costs.

The system costs that could be avoided through DR deployment are estimated based on market data that is specific to NSP's service territory. Assumptions used in developing each marginal (i.e., avoidable) cost estimate are described in more detail below, for both the Base Case and the High Sensitivity Case.

Avoided generation capacity costs

DR programs are most appropriately recognized as substitutes for new combustion turbine (CT) capacity. CTs are "peaking" units with relatively low up-front installation costs and high variable costs. As a result, they typically only run up to a few hundred hours of the year, when electricity demand is very high and/or there are system reliability concerns. Similarly, use of DR programs in the U.S. is typically limited to less than 100 hours per year. This constraint is either written into the DR program tariff or is otherwise a practical consideration to avoid customer fatigue and program drop-outs.

In contrast, new intermediate or baseload capacity (e.g., gas-fired combined cycle) has a higher capital cost and lower variable cost than a CT, and therefore could run for thousands of hours per year. The DR programs considered in this study cannot feasibly avoid the need for new intermediate or baseload capacity, because they cannot be called during a sufficient number of hours of the year. Energy efficiency is a more comparable demand-side alternative to these resource types since it is a permanent load reduction that applies to a much broader range of hours.

In the Base Case, the installed cost of new CT capacity is based on data provided directly by NSP and consistent with the assumptions in NSP's 2019 IRP for a brownfield CT. The total cost amounts to $60.60/kW-year; this is sometimes referred to the gross cost of new entry (CONE). The gross CONE value is adjusted downward to account for the energy and ancillary services value that would otherwise be provided by that unit. Based on simulated unit profit data provided by NSP, we have estimated the annual energy and ancillary services value to be roughly $5.50/kW-year. The resulting net CONE value is $55.20/kW-year. This calculation is described further in Table 9 below.

This same approach is used to establish the capacity cost for the High Sensitivity Case. Rather than using the CT cost from NSP's IRP, we relied on the U.S. Energy Information Administration's (EIA's) estimate of the installed cost of an Advanced CT from the 2018 Annual Energy Outlook. For the Midwest Reliability Organization West region, this amounts to a gross CONE of $76.80/kW-year. Reducing this value by the same energy and ancillary services value described above leads to a net CONE of $71.40/kW-year.

Table 9: Combustion Turbine Cost of New Entry Calculation

Variable		NSP 2019 IRP Brownfield CT	NSP 2019 IRP Greenfield CT	AEO 2018 Advanced CT
Overnight Capital Cost ($/kW)	[1]	$467	$617	$698
Effective Charge Rate (%)	[2]	10%	10%	10%
Levelized Capital Cost ($/kW-yr)	[3]=[1]x[2]	$46.7	$61.7	$69.8
Annual Fixed Costs ($/kW-yr)	[4]	$13.9	$13.9	$7.0
Gross Cost of New Entry ($/kW-yr)	[5]=[3]+[4]	$60.6	$75.6	$76.8
E&AS Margins ($/kW-yr)	[6]	$5.5	$5.5	$5.5
Net Cost of New Entry ($/kW-yr)	[7]=[5]-[6]	$55.2	$70.2	$71.4

Notes: All costs shown in 2018 dollars. Assumes that overnight capital costs are recovered at 10% effective charge rate. AEO 2018 advanced CT costs shown for the Midwest Reliability Organization West region. Capacity costs are held constant in real terms throughout the period of study.

DR produces a reduction in consumption at the customer's premise (i.e. at the meter). Due energy losses on transmission and distribution lines as electricity is delivered from power plants to customer premises, a reduction in one kilowatt of demand at the meter avoids more than one kilowatt of generation capacity. In other words, assuming line losses of 8% percent, a power plant must generate 1.08 kW in order to deliver 1 kW to an individual premise.[27] When estimating the avoided capacity cost of DR, the avoided cost is grossed up to account for this factor. For this study, Xcel Energy provided load data at the generator level, thus already accounting for line loss gross-up.

Similarly, NSP incorporates a planning reserve margin of 2.4% percent into its capacity investment decisions.[28] This effectively means NSP will plan to have enough capacity available to meet its projected peak demand plus 2.4% percent of that value. In this sense, a reduction of one kilowatt at the meter level reduces the need for 1.024 kW of capacity. Including the 2.4% reserve margin adjustment increases the net CONE value described above from $55.2 and $71.4/kW-year to $56.5 and $73.1/kW-year, for the Base and High Sensitivity Cases respectively. This is the generation capacity value that could be provided by DR if it were to operate exactly like a CT.

Avoided transmission capacity costs

Reductions in system peak demand may also reduce the need for transmission upgrades. A portion of transmission investment is driven by the need to have enough capacity available to

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27 8% represents an average line loss across NSP territories and customer segments. Actual line losses range from 2 to 10%.

28 NSP's planning reserve margin target is 7.8% of load during the MISO peak, which translates into a margin of 2.4% during its own system peak.

move electricity to where it is needed during peak times while maintaining a sufficient level of reliability. Other transmission investments will not be peak related, but rather are intended to extend the grid to remotely located sources of generation, or to address constraints during mid- or off-peak periods. Based on the findings of NSP's 2017 T&D Avoided Cost Study for energy efficiency programs, we have assumed an avoidable transmission cost of $3.10/kW-year in 2023, rising to $3.60/kW-year in 2030.[29]

Avoided system-wide distribution capacity costs

Similar to transmission value, there may be long-term distribution capacity investment avoidance value associated with reductions in peak demand across the NSP system. For programs that do not provide the higher-value distribution benefits from geo-targeted deployment, as described below, we have assumed that peak demand reductions can produce avoided distribution costs of $8.10/kW-year in 2023, rising to $9.50/kW-year in 2030, based on NSP's 2017 T&D Avoided Cost Study.

Geo-targeted distribution capacity costs

DR participants may be recruited in locations on the distribution system where load reductions would defer the need for local capacity upgrades. This local deployment of the DR program can be targeted at specifically locations where distribution upgrades are expected to be costly.

DR cannot serve as a substitute for distribution upgrades in all cases, such as adding new circuit breakers, telemetry upgrades, or adding distribution lines to connect new customers. However, in many cases, system upgrades are needed to meet anticipated gradual load growth in a local area. At times, system planners must over-size distribution investments relative to the immediate needs to meet local load to allow for future load growth or utilize equipment (such as transformers) that only comes in certain standard sizes. To the extent that DR can be used to reduce local peak loads, the loading on the distribution system is reduced, which means otherwise necessary distribution upgrades may be deferred. Such deferrals are especially valuable if load growth is relatively slow and predictable such that the upgraded system would not be fully utilized for many years.

To quantify geo-targeted distribution capacity deferral value in Load*Flex*, we began with a list of all distribution capacity projects in NSP's five-year plan. Brattle worked with NSP staff to reduce this list to a subset of projects that are likely candidates for deferral through DR. Four criteria were applied to identify the list of candidate deferral projects:

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[29] Xcel Energy, Minnesota Power, Otter Tail Power Company, Mendota Group & Environmental Economics, "Minnesota Transmission and Distribution Avoided Cost Study," July 31, 2017.

1. The need for the distribution project must be driven by load growth. DR could not be used to avoid the need to simply replace aging equipment, for example.

2. The project must have a meaningful overall cost on a per-kilowatt basis. In our analysis, we required that the cost of the project equate to a value of at least $100,000 per megawatt of reduced demand in order to be considered.[30] This is the equivalent of roughly $7/kW-year on an annualized basis. Projects below this cost threshold were excluded from the geo-targeted deferral analysis.

3. There must be sufficient local customer load in order for the upgrade to be deferrable through the use of DR. For instance, if a 20 MW load reduction would be needed to avoid a specific distribution upgrade, and there was only 25 MW of total load at that location in the system, then DR would not be a useful candidate because it is unlikely that DR could consistently and reliably produce an 80% load reduction. In establishing this criterion, projects with more than 6 MVA of "load at risk"[31] were excluded, as 6 MVA represents about half of the load on a typical feeder.

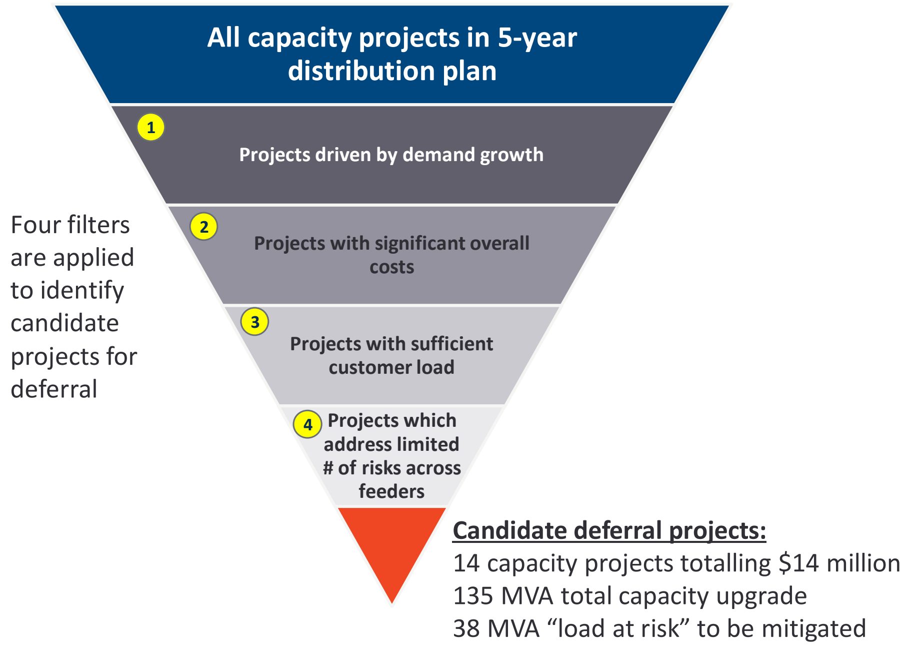
4. The project should not be needed to simultaneously address many risks across feeders. In some cases, distribution upgrades are needed to mitigate a number of different contingencies. There are significant operational challenges associated with using DR in a similar manner. Projects were screened out based on the number and severity of risks that they were intended to address.

After applying the above criteria, up to roughly 10% of the cost of NSP's 5-year plan remained as potentially deferrable through the use of DR. We have assumed linear growth in NSP's distribution capacity needs, meaning the geo-targeted distribution deferral opportunity increases by this amount every five years over the forecast horizon. Figure 17 summarizes the process for identifying geo-targeted distribution deferral opportunities.

30 For simplicity, we assumed 1 MVA = 1 MW.

31 "Load at risk" effectively represents the load reduction that would need to be achieved to defer the capacity upgrade.

Figure 18: Identification of Candidates for Geo-targeted Distribution Investment Deferral



Avoided energy costs

Load can be shifted from hours with higher energy costs to hours with lower energy costs, thus producing net energy cost savings across the system.[32] Hourly energy costs in this study are based on the 2018 MISO Transmission Expansion Plan (MTEP18) modeled day-ahead prices for the NSP hub. These modeled prices were used to capture evolving future system conditions that would not be reflected in historical prices. MTEP18 presents four "futures" that represent broadly different long-term views of MISO energy system, enabling the evaluation of the avoided energy value of DR under different market conditions.

For the Base Case, we relied on prices from MTEP18's Continued Fleet Change (CFC) future. This future assumes a continuation of trends in the MISO market from the past decade: persistent low gas prices, limited demand growth, continued economic coal retirements, and gradual growth in renewables above state requirements.[33] Figure 19 below shows that 2022 energy prices

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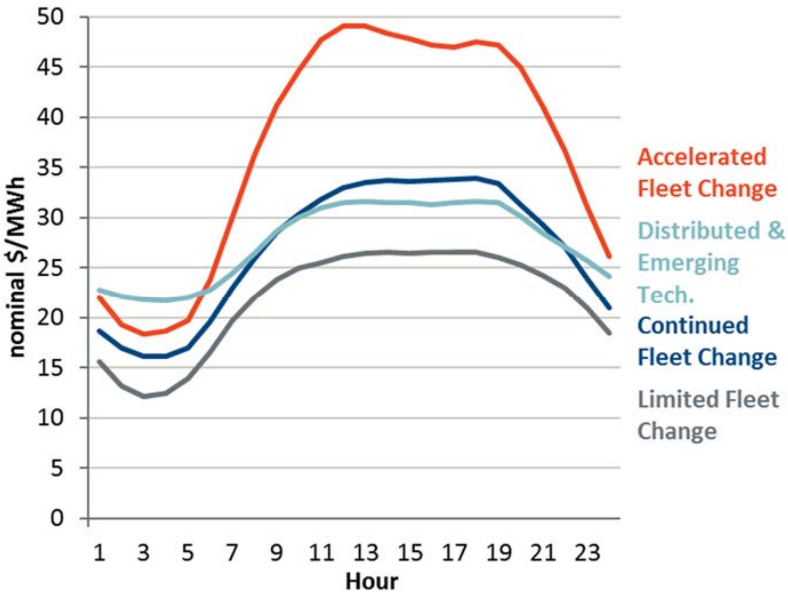
32 Energy savings refer to reduced fuel and O&M costs. In this study, we do not model the impact that DR would have on MISO wholesale energy prices. This is sometimes referred to as the demand response induced price effect (DRIPE). It represents a benefit to consumers and an offsetting cost to producers, with no net change in costs across the system as a whole.

33 See MISO, "MTEP 18 Futures – Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results." for additional details on MTEP18 scenarios.

under the CFC future lie somewhere in the middle of the four MTEP scenarios (energy prices in other years follow the same relative pattern across scenarios).

Figure 19: Average Energy Price by Hour of Day in 2022 MTEP Scenarios for NSP Hub



For the High Sensitivity Case, we relied on prices from the Accelerated Fleet Change (AFC) future. The AFC case has twice the amount of renewable generation capacity additions as the CFC future. However, increased load growth, accelerated coal retirements, and higher gas prices lead to overall higher energy prices, particularly in daytime hours. For our analysis years (2023, 2025 and 2030), we relied on prices from the nearest MTEP modeling year (2022, 2027, and 2032, respectively) and adjusted them accordingly for inflation (assumed to be 2.2% per year).

Ancillary services

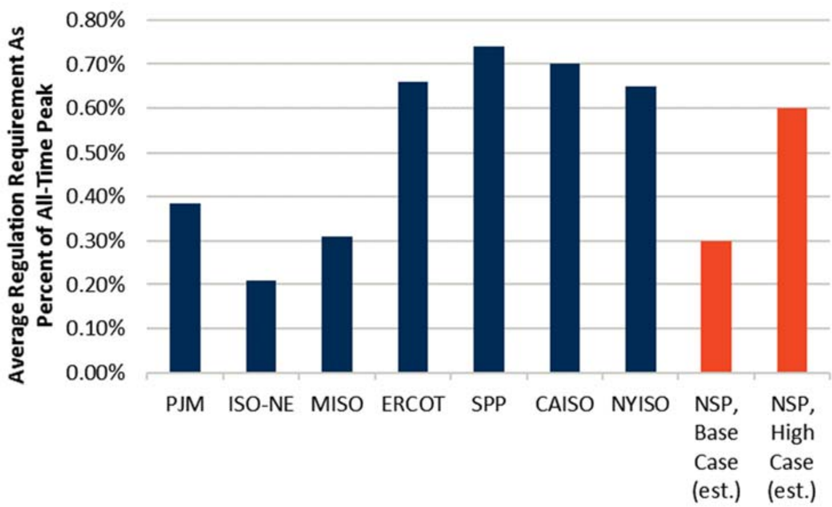
The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service.

Frequency regulation is a high value resource with a very limited need. Across most markets, the need for frequency regulation capacity is less than 1% of the system peak. We assume that the frequency regulation needs in the NSP system across all analysis years are 25 MW (0.3% of annual peak) in the Base Case, and 50 MW in the High Sensitivity Case (0.6% of annual peak).[34] Figure 20 summarizes frequency regulation needs across various U.S. markets, demonstrating

[34] Calculated assuming an annual peak of 8,335 MW after line losses.

that the quantities of frequency regulation assumed in this study are consistent with experience elsewhere.

Figure 20: Frequency Regulation Requirements Across Wholesale Markets



Sources and Notes: Values for wholesale markets extracted from PJM, "RTO/ISO Regulation Market Comparison", April 13, 2016. Orange bars for NSP assume that NSP's all-time peak is 8,335 MW at the customer level, based on three years of provided peak load data and assumed 8% line losses. Frequency regulation values for all markets are average levels as of 2016.

Because regulation prices were not available from the 2018 MTEP, we utilized 2017 hourly generation regulation prices for the MISO system adjusted for inflation.

Table 10 summarizes the potential value of each DR benefit. Values shown are the maximum achievable value. Operational constraints of the DR resources (e.g., limits on number of load curtailments per year) often result in realized benefits estimates that are lower than the values shown.

Table 10: Summary of Avoided Costs/Value Streams in 2023

Value Stream	Quantity of Need		Avoided Cost		Description
	Base Case	High Case	Base Case	High Case	
Avoided Generation Capacity	Unconstrained	Unconstrained	$63.0/kW-year	$81.5/kW-year	Base: Xcel's Brownfield CT costs minus estimated CT energy revenues from 2018 IRP, plus 2.4% reserve margin gross-up.
Avoided Transmission Capacity	Unconstrained	Unconstrained	$3.1/kW-year	$3.1/kW-year	72% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Avoided Distribution Capacity	Unconstrained	Unconstrained	$8.0/kW-year	$8.0/kW-year	28% of avoided transmission & distribution costs estimated under the discrete valuation approach in Xcel's 2017 T&D Avoided Cost Study.
Geo-targeted Distribution Capacity	38 MW	38 MW	$25.8/kW-year	$25.8/kW-year	Total value of 14 projects identified as eligible for distribution capacity deferral by demand response.
Frequency Regulation	25 MW	50 MW	Avg: $12.4/MWh	Avg: $12.4/MWh	2017 MISO regulation prices. Assumes that NSP's share of regulation need is 25 MW in 2023 and 50 MW in 2030.
Avoided Energy	Unconstrained	Unconstrained	Avg: $27.5/MWh	Avg: $27.5/MWh	Hourly MISO MTEP18 modeled energy prices for NSP HUB. 2023 used prices from the CFC 2022 scenario, and 2030 used prices from the AFC 2032 scenario.
Top 10% Average			$50.5/MWh	$71.3/MWh	
Bottom 10% Average			$8.1/MWh	$8.6/MWh	

Notes:
All values shown in nominal dollars. 2030 avoided costs are similar, rising at inflation.

Step 3: Develop 8,760 hourly profile of marginal costs

Each of the annual avoided cost estimates established in Step 2 is converted into a chronological profile of hourly costs for all 8,760 hours of the year. In each hour, these estimates are added together across all value streams to establish the total "stacked" value that is obtainable through a reduction in load in that hour (or, conversely, the total cost associated with an increase in load in that hour).

Capacity costs are allocated to hours of the year proportional to the likelihood that those hours will drive the need for new capacity. In other words, the greater the risk of a capacity shortage in a given hour, the larger the share the marginal capacity cost that is allocated to that hour.

Capacity costs are allocated across the top 100 load hours of the year. The allocation is roughly proportional to each hour's share of total load in the hours. This means more capacity value is allocated to the top load hour than the 100th load hour.

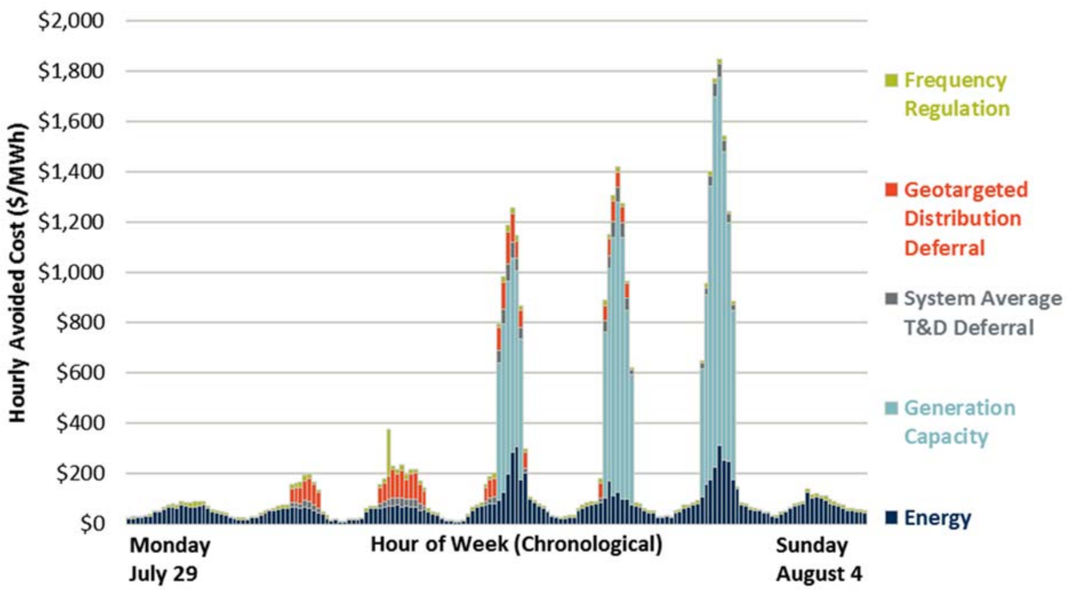
Different allocators are used to allocate generation, transmission, and distribution capacity costs. Generation and transmission capacity costs are allocated based on 2017 hourly MISO system gross load.[35] Distribution capacity costs are allocated based on hourly feeder load data provided by NSP. Both generic distribution capacity deferral and geo-targeted distribution capacity deferral value are allocated over a larger number of peak hours (roughly 330 hours, rather than 100 hours), representing that a single distribution project will address multiple feeders with load profiles that are only partially coincident.

A conceptually similar approach to quantifying capacity value is used in the California Energy Commission's time-dependent valuation (TDV) methodology for quantifying the value of energy efficiency, and also in the CPUC's demand response cost-effectiveness evaluation protocols. This hourly allocation-based approach effectively derates the value of distributed resources relative to the avoided cost of new peaking capacity by accounting for constraints that may exist on the operator's ability to predict and respond to resource adequacy needs. These constraints could result in DR utilization patterns that reflect a willingness to bypass some generation capacity value in order to provide distribution deferral value, for instance. The approach is effectively a theoretical construct intended to quantify long-term capacity value, rather than reflecting the way resource adequacy payments would be monetized by a DR operator in a wholesale market.

Figure 21 illustrates the "stacked" marginal costs associated with each value stream for a single week in the study period. The figure shows that certain hours present a significantly larger opportunity to reduce costs through load reduction – namely, those hours to which capacity costs are allocated.

[35] Capacity value was allocated proportional to MISO gross load because NSP is required to use its MISO-coincident peak for resource adequacy planning decisions.

Figure 21: Chronological Allocation of Marginal Costs (Illustration for Week of July 29)



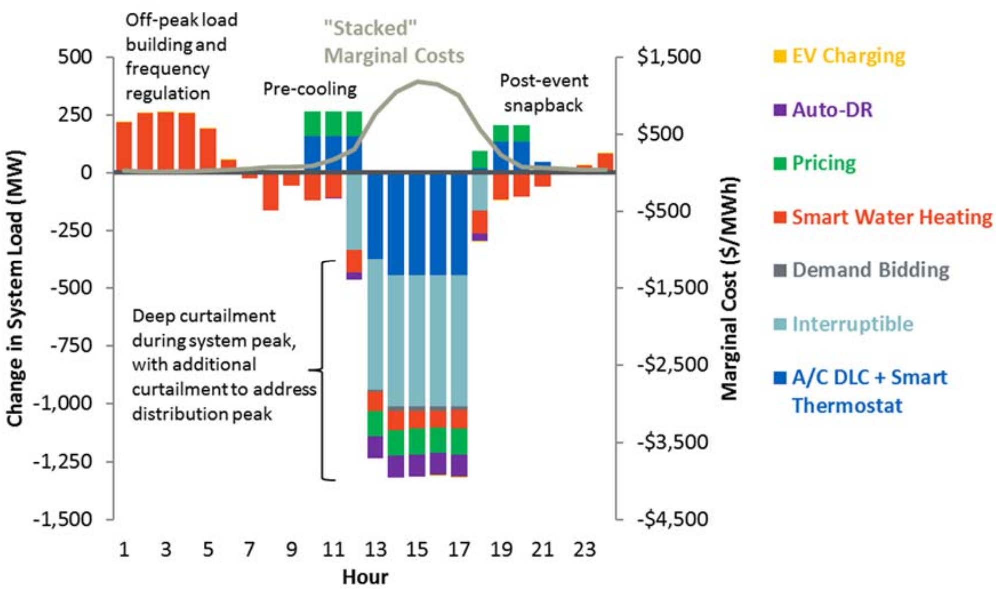
Notes: Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

Step 4: Optimally dispatch programs and calculate benefit-cost metrics

As discussed above, using DR to pursue one value stream may require forgoing opportunities to pursue other "competing" sources of value. While the value streams quantified in this study can be estimated individually, those estimates are not purely additive. A DR operator must choose how to operate the program in order to maximize its value. Accurately estimating the total value of DR programs requires accounting for tradeoffs across the value streams.

Load*Flex* employs an algorithm that "co-optimizes" the dispatch of a DR program across the hourly marginal cost series from Step 3, subject to the operational constraints defined in Step 1, such that overall system value produced by the program is maximized. In other words, the programs are operated to reduce load during hours when the total cost is highest and build load during hours when the total cost is lowest, without violating any of the established conditions around their use. Figure 22 illustrates how the dispatch of the High Sensitivity Case portfolio in this study compares to the hourly cost profile on those same days.

Figure 22: Illustrative Program Operations Relative to "Stacked" Marginal Costs



Through an iterative process, Load*Flex* determines when the need for a given value stream has been fully satisfied by DR in each hour, and excludes that value stream from that hour for incremental additions of DR. This ensures that DR is not over-supplying certain resources and being incorrectly credited for services that do not provide additional value to the system.

Step 5: Identify cost-effective incentive and participation levels

A unique feature of Load*Flex* is the ability to identify participation levels that are consistent with the incentive payments that are economically justified for each DR program. This ensures that each program's economic potential estimate is based on an incentive payment level that produces a benefit-cost ratio of 1.0. Without this functionality, the analysis would under-represent the potential for a given DR program, or could even exclude it from the analysis entirely based on inaccurate assumptions about uneconomic incentive payments levels.

As a starting point, participation estimates for each DR program are established to represent the maximum enrollment that is likely to be achieved when offered in NSP's service territory at a "typical" incentive payment level. The estimates are tailored to NSP's customer base using data on current program enrollment, as well as survey-based market research conducted directly with

NSP's customers.[36] For DR programs not included in the market research study, we developed participation assumptions based on experience with similar programs in other jurisdictions and applied judgement to make the participation rates consistent with available evidence that is specific to NSP's customer base.

Table 11 summarizes these "base" participation rates for conventional DR programs. In all cases, participation is expressed as a percent of the eligible customer base. For instance, the population of customers eligible for the smart thermostat program is limited to those customers with central air-conditioning.

The 2017 values represent current participation levels. Values in future years reflect participation rates if the programs were offered as part of an expanded DR portfolio. This accounts for the fact that a single customer could not simultaneously participate in two different programs.

Residential air-conditioning load control participation assumptions reflect a transition from compressor switch-based direct load control program to a smart thermostat-based program. These programs are currently marketed by NSP as "Savers Switch" and "AC Rewards", respectively. Based on the aforementioned primary market research conducted in NSP's service territory, we estimate that a 66% participation rate among eligible customers is achievable at the medium incentive level for these programs collectively. In 2017, participation in air-conditioning load control programs reached 52% of eligible residential customers, mostly through the Savers Switch program. In the future, NSP will increase its marketing emphasis on the AC Rewards program as its primary air-conditioning load control program. Therefore, we assume that achievable incremental participation in residential air-conditioning load control transitions from an equal split between AC Rewards and Savers Switch in 2018 to a 75/25 split in favor of AC Rewards by 2023. Additionally, NSP will focus on transitioning customers from Savers Switch to AC Rewards as compressor switches reach the end of their useful life. Based on information about the age of deployed switches and conversations with NSP, we assume that the number of switches replaced by smart thermostats grows from around 6,600/year in 2018 to 10,000/year in 2023 and onwards.

It is important to note that the participation rates shown are consistent with a participation incentive payment level that is representative of common offerings across the U.S. Participation rates are shown for all programs at these incentive levels, regardless of whether or not the programs are cost-effective at those incentive levels.[37] Later in this section of the appendix, we describe adjustments that are made to these "base" incentive levels to reflect enrollment that could be achieved at cost-effective incentive levels.

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[36] Ahmad Faruqui, Ryan Hledik, and David Lineweber, "Demand Response Market Potential in Xcel Energy's Northern States Power Service Territory," April 2014.

[37] This is the basis for our estimate of "technical potential".

Table 11: Participation Assumptions for Conventional DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	A/C DLC - SFH	52%	50%	39%
Residential	Smart thermostat - SFH	0%	16%	24%
Residential	Smart thermostat - MDU	0%	35%	32%
Small C&I	A/C DLC	0%	30%	30%
Small C&I	Interruptible	0%	14%	12%
Small C&I	Demand Bidding	0%	2%	1%
Medium C&I	A/C DLC	73%	64%	64%
Medium C&I	Interruptible	3%	13%	11%
Medium C&I	Demand Bidding	0%	6%	5%
Large C&I	Interruptible	12%	44%	43%
Large C&I	Demand Bidding	0%	5%	4%

Notes:

Participation rates shown for programs at the portfolio level (i.e. accounts for program overlap). Lower participation rates for some programs in 2030 relative to 2023 result from customers switching to an opt-in CPP rate (for which participation estimates are shown separately). High Medium C&I participation in A/C DLC is relative to a small portion of the customer segment that is eligible for enrollment.

Table 12 illustrates the potential participation rates for each new DR program analyzed in the study. As noted above, these enrollment rates are consistent with "base" incentive payment levels and do not reflect enrollment associated with cost-effective payment levels. **Here, participation in each program is shown as if the program were offered in isolation.** In other words, it is the achievable participation level in the absence of other programs being offered. In our assessment of expanded DR portfolios that include multiple new DR programs, restrictions on participation in multiple programs are accounted for and the participation rates are derated accordingly.

Table 12: Participation Assumptions for New DR Programs

Participation as a percentage of eligible customers

Segment	Program	2017	2023	2030
Residential	Behavioral DR (Opt-out)	0%	80%	80%
Residential	CPP (Opt-in)	0%	0%	20%
Residential	CPP (Opt-out)	0%	0%	80%
Residential	EV Managed Charging - Home	0%	20%	20%
Residential	EV Managed Charging - Work	0%	20%	20%
Residential	Smart water heating	0%	15%	50%
Residential	Timed water heating	0%	50%	50%
Residential	TOU - EV Charging (Opt-in)	0%	0%	20%
Residential	TOU (Opt-in)	1%	0%	16%
Residential	TOU (Opt-out)	0%	0%	80%
Small C&I	Auto-DR (A/C)	0%	5%	5%
Small C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Small C&I	Auto-DR (Light Zonal)	0%	5%	5%
Small C&I	CPP (Opt-in)	0%	0%	20%
Small C&I	CPP (Opt-out)	0%	0%	80%
Small C&I	TOU (Opt-in)	3%	0%	10%
Small C&I	TOU (Opt-out)	0%	0%	80%
Medium C&I	Auto-DR (HVAC)	0%	5%	5%
Medium C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Medium C&I	Auto-DR (Light Zonal)	0%	5%	5%
Medium C&I	CPP (Opt-in)	0%	14%	14%
Medium C&I	CPP (Opt-out)	0%	79%	79%
Medium C&I	Thermal Storage	0%	3%	3%
Medium C&I	TOU (Opt-in)	21%	19%	19%
Medium C&I	TOU (Opt-out)	0%	0%	80%
Large C&I	Auto-DR (HVAC)	0%	5%	5%
Large C&I	Auto-DR (Light Luminaire)	0%	5%	5%
Large C&I	Auto-DR (Light Zonal)	0%	5%	5%
Large C&I	CPP (Opt-in)	0%	22%	22%
Large C&I	CPP (Opt-out)	0%	81%	81%
Large C&I	TOU (Opt-in)	100%	100%	100%

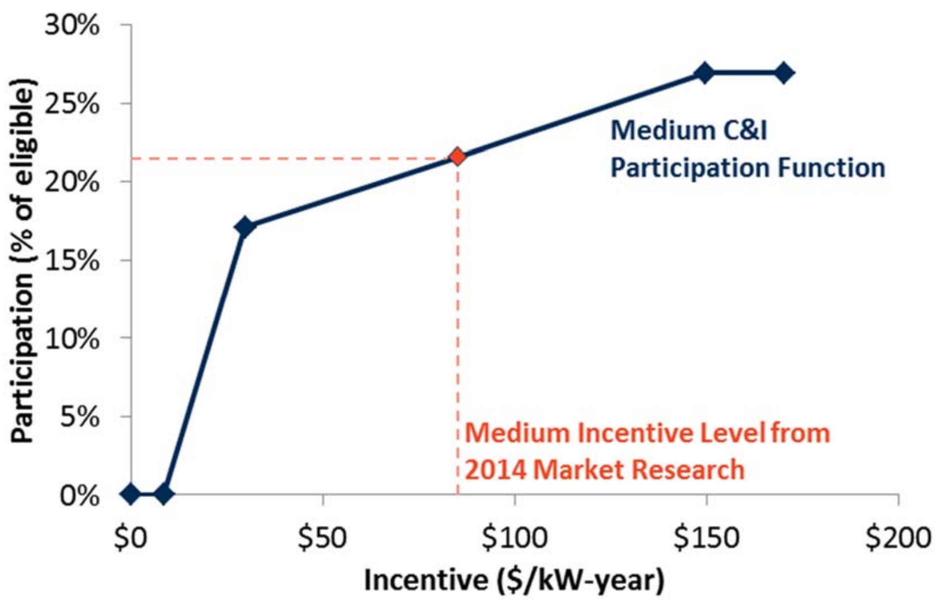
Notes:
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

As discussed above, the cost-effectiveness screening process in many DR potential studies often treats programs as an all-or-nothing proposition. In other words, the studies commonly assume a base incentive level and then simply evaluate the cost-effectiveness of the programs relative to that incentive level. However, in reality, the incentives can be decreased or increased to accommodate lower or higher thresholds for cost effectiveness. For instance, in a region with lower avoided cost, a lower incentive payment could be offered, and vice versa. Program participation will vary according to these changes in the incentive payment level.

In Load*Flex* model, participation is expressed as a function of the assumed incentive level. The incentive level that produces a benefit-cost ratio of 1.0 is quantified, thus defining the maximum potential cost-effective participation for the program.[38] The DR adoption function for each program is derived from the results of the aforementioned 2014 market research study, which tested customer willingness to participate in DR programs at various incentive levels.

An illustration of the participation function for the Medium C&I Interruptible program is provided in Figure 23. The figure expresses participation in the program (vertical axis) as a function of the customer incentive payment level (horizontal axis). At an incentive level of around $85/kW-yr, slightly more than 20% of eligible customers would participate in the program. If the economics of the program could only justify an incentive payment less than this (e.g., due to low avoided capacity costs), participation would decrease according to the blue line in the chart, and vice versa. Below an incentive payment level of around $25/kW-yr, customer willingness to enroll in the program quickly drops off.

Figure 23: Medium C&I Interruptible Tariff Adoption Function



Step 6: Estimate cost-effective DR potential

After the cost-effective potential of each individual DR program is estimated, the programs are combined into a portfolio. Constructing the portfolio is not as simple as adding up the potential estimates of each individual program. In some cases, two programs may be targeting the same end-use (e.g., timed water heating and smart water heating), so their impacts are not additive.

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38 In some cases, the non-incentive costs (e.g., equipment costs) outweigh the benefits, in which case the program does not pass the cost-effectiveness screen.

In instances where two cost-effective programs target the exact same end-use, we have assumed that the portfolio would only include the program that produces the larger impact by the end of the study horizon. In the water heating example, this means that the smart water heating program was included and the timed water heating program was not.

In other cases, two "competing" programs would likely be offered simultaneously to customers as mutually exclusive options. For instance, it is possible that C&I customers would only be allowed to enroll in either an interruptible tariff program or a CPP rate. Simultaneous enrollment in both could result in customer being compensated twice for the same load reduction – once through the incentive payment in the interruptible tariff, and a second time through avoiding the higher peak price of the CPP rate. In these cases, we relied on the results of the aforementioned 2014 market research study, which used surveys to determine relative customer preferences for these options when offered simultaneously. Participation rates were reduced in the portfolio to account for this overlap.

In cases where two programs would be offered simultaneously to the same customer segment, but would target entirely different end-uses (e.g., a smart thermostat program and an EV charging load control program), no adjustments to the participation rates were deemed necessary.

Appendix B: NSP's Proposed Portfolio

At a stakeholder meeting on August 8, 2018, NSP presented a draft portfolio of proposed DR programs. The DR portfolio that NSP is considering consists of the programs and deployment years summarized in Table 13.

Table 13: NSP's Draft Portfolio of DR Programs

Program	First Year of Rollout
Saver's Switch	Existing
A/C Rewards	Existing
EV home charging control	2020
Med/large C&I Auto-DR	2021
Med/large C&I interruptible tariff (program expansion)	2021
Med/large C&I Opt-in CPP	2022
Residential smart water heating	2023
Residential behavioral DR	2023
Residential opt-out TOU	2024

The potential for this portfolio was quantified under the Base and High Sensitivity cases for years 2023 and 2030. Results are summarized in Table 14. In the table, the values in the row labeled "All Proposed Programs" indicate the incremental technical potential in each of the programs that have been proposed by NSP. The values in the row "Cost-Effective Proposed programs" indicate the amount of incremental DR in the proposed programs that can be achieved at cost-effective incentive payment levels. In both cases, DR potential is shown at the portfolio level, accounting for overlap in participation when multiple programs are offered simultaneously.

Table 14: Incremental Potential in NSP's Draft Portfolio of DR Programs (MW)

	Base Case		High Sensitivity Case	
	2023	**2030**	**2023**	**2030**
All Proposed Programs	642	907	658	927
Cost-Effective Proposed Programs	262	461	411	677

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix C: Base Case with Alternative Capacity Costs

For its 2019 IRP, NSP has developed cost assumptions for new CT capacity at brownfield and greenfield sites. Our Base Case assumptions rely on brownfield CT costs as the avoided generation cost estimate, as this is the lowest cost option available to NSP for future peaking generation development. To test the sensitivity of our findings to that assumption, we modeled an alternative case in which the avoided capacity cost in the Base Case is based on a greenfield CT rather than a brownfield CT.[39] Other Base Case assumptions remained unchanged.

The greenfield CT capacity cost is higher than the brownfield CT cost, which increases the benefits of DR programs due to higher avoided generation costs. Relative to the Base Case, the cost-effective incremental potential in the DR portfolio increases by 73 MW in 2023 and by 119 MW in 2030. Nearly all of this increase in potential is attributable to a further expansion of participation in programs that were already cost-effective in the Base Case. The additional potential is mostly in the smart thermostat program, increases from 112 MW to 148 MW in 2023 and from 169 MW to 220 MW in 2030. Other programs that were economic in the Base Case (residential smart water heating, additional C&I interruptible, and demand bidding) also have small increases in cost-effective potential.

The only program that was initially uneconomic under Base assumptions but becomes economic under the greenfield CT capacity cost assumption is HVAC-based Auto-DR: 3 MW of Large C&I Auto-DR becomes cost-effective in 2023, growing to 6 MW in 2030 (in addition to 32 MW of Medium C&I Auto-DR). Together, these programs account for 4% of additional potential in 2023, but over 30% of additional potential in 2030.

Table 15 compares the portfolio-level incremental DR potential for the Base Case with brownfield CT costs to the alternative case with greenfield CT costs. Annual program-level potential estimates are provided in Appendix D.

[39] Table 9 of this report summarizes the greenfield, brownfield and AEO 2018 CT costs used in this analysis.

Table 15: Incremental Cost-Effective Potential in Portfolio of DR Programs with Alternative CT Costs (MW)

	2023	2030
Base Case (Brownfield CT Cost)	306	468
Alternative Case (Greenfield CT Cost)	378	587
Difference (Alternative - Base)	73	119

Note: Values shown are incremental to the existing 850 MW portfolio.

Appendix D: Annual Results Summary

Base Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	6	11	17	23	29	30	34	40	49	60
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	20	20	20	20	20	20	20
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	1	1	4	6	6	6	6	7	7
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	4	9	13	17	22	23	25	29	35	42
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	19	19	19	21	22	22	22	22	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	32	32	32	31	30	30	30	30	30	30
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	14	18	16	15	15	15	15	15	15
Medium C&I	Interruptible	45	45	45	31	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	1	6	7	6	5	5	5	5	5	5
Large C&I	Interruptible	58	58	58	55	51	51	50	49	48	47
Portfolio-Level Total		**276**	**296**	**306**	**338**	**393**	**405**	**418**	**433**	**450**	**468**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	16	16	16	16	16	17	17
Residential	Smart thermostat - SFH	180	180	180	204	227	245	262	280	298	315
Residential	Smart water heating	6	13	19	26	33	34	38	44	53	65
Residential	Timed water heating	11	43	54	55	55	55	55	56	56	56
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	16	20	21	21	21	21	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	19
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:

Figure shows incremental load reduction available when DR programs are offered in isolation.

Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Alternative Base Case with Greenfield CT Costs, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	2	10	12	12	12	12	12	12	13	13
Residential	Smart thermostat - SFH	148	148	148	159	170	180	190	200	210	220
Residential	Smart water heating	5	10	15	21	26	27	30	35	42	51
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	31	31	31	31	32	32	32	32	32	32
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	9	18	20	23	26	29	32
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	19	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	21	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	1	2	3	4	5	5	5	5	6	6
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	6	5	5	5	5	5	5
Large C&I	Interruptible	61	61	61	58	54	53	52	51	50	49
Portfolio-Level Total		**335**	**365**	**378**	**418**	**480**	**498**	**517**	**538**	**562**	**587**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	52	52	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	15	62	65	69	73	76	80
Residential	CPP (Opt-out)	0	0	0	157	157	159	160	161	163	164
Residential	EV Managed Charging - Home	1	2	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	1	1	1	2	2	3	3	3
Residential	Smart thermostat - MDU	3	13	16	17	17	17	17	17	17	17
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	11	45	57	66	76	76	75	75	75	74
Residential	TOU (Opt-in)	0	0	0	6	23	25	26	28	29	31
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	1	1	1	2	2	2
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	2	8	9	9	9	10	10	10	10	10
Small C&I	Auto-DR (Light Luminaire)	1	6	7	7	7	7	7	7	8	8
Small C&I	Auto-DR (Light Zonal)	1	5	6	6	6	6	6	6	6	6
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	1	1	1	1	1	1	1
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	65	65	65	65	66	66	66	67	67	67
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	6	24	30	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	86	86	86	87	87	88	89	89	90	90
Medium C&I	Demand Bidding	4	17	21	21	22	22	22	22	22	22
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	20	80	100	101	101	101	102	102	103	103
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	51	51	51	51	52	52	52
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	7	28	36	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	64	64	64	64	64	63	63	63	63	62
Large C&I	Demand Bidding	2	6	8	8	8	8	8	8	8	8
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, All Programs

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	11	44	46	49	52	54	57
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	3	12	15	15	15	15	15	15	15	15
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	8	16	24	32	40	42	47	56	68	83
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	1	1	2	2
Small C&I	A/C DLC	32	32	32	32	32	32	32	33	33	33
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	34	34	34	32	31	31	31	31	31	31
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	0	0	10	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	4	16	20	18	16	16	16	16	16	16
Medium C&I	Interruptible	47	47	47	32	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	0	0	16	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	2	6	8	7	5	5	5	5	5	5
Large C&I	Interruptible	62	62	62	58	55	54	53	52	51	50
Portfolio-Level Total		**380**	**454**	**484**	**524**	**586**	**603**	**623**	**647**	**674**	**705**

Notes:

Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.

No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	161	161	161	175	190	204	219	233	248	262
Residential	Smart water heating	0	0	8	15	22	23	26	31	39	48
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

Base Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	112	112	112	122	131	139	146	154	162	169
Residential	Smart water heating	0	0	8	13	18	19	21	25	30	36
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	21	21	21	22	23	23	23	23	22	22
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	14	14	14	14	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	13	13	13	15	16	17	18	19	20	22
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	52	52	52	52	51	51	50	49	48	47
Portfolio-Level Total		**213**	**223**	**262**	**384**	**400**	**410**	**420**	**433**	**446**	**461**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	52	53	53	54	54	54	55	55
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	2	3	3	5	7	9	12	14	16	18
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	213	213	213	238	263	283	302	321	341	360
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	155	155	156	157	159	160	161
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	44	44	44	44	44	44	45	45	45	45
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	53	53	53	53	54	54	54	54	54	55
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	1	1	1	1	1
Medium C&I	A/C DLC	3	3	3	4	4	4	5	5	5	6
Medium C&I	Auto-DR (HVAC)	30	121	151	152	152	153	154	154	155	156
Medium C&I	Auto-DR (Light Luminaire)	12	48	60	60	60	60	61	61	61	62
Medium C&I	Auto-DR (Light Zonal)	6	26	32	32	32	33	33	33	33	33
Medium C&I	CPP (Opt-in)	0	6	24	30	30	30	30	31	31	31
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	310	310	310	313	316	318	321	324	326	329
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	4	15	19	19	19	19	19	19	19	18
Large C&I	Auto-DR (Light Luminaire)	3	11	13	13	13	13	13	13	13	13
Large C&I	Auto-DR (Light Zonal)	1	6	7	7	7	7	7	7	7	7
Large C&I	CPP (Opt-in)	0	7	28	35	35	35	35	35	35	35
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	85	85	85	84	83	82	81	80	79	78

Notes:
Figure shows incremental load reduction available when DR programs are offered in isolation.
Measure-level results do not account for cost-effectiveness or overlap when offered simultaneously as part of a portfolio.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

High Sensitivity Case, NSP Proposed Portfolio

Cost-Effective Potential (MW, at generator-level)

Segment	Program	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Residential	A/C DLC - SFH	0	0	0	0	0	0	0	0	0	0
Residential	Behavioral DR (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Home	0	0	0	0	0	0	0	0	0	0
Residential	EV Managed Charging - Work	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - MDU	0	0	0	0	0	0	0	0	0	0
Residential	Smart thermostat - SFH	176	176	176	186	197	208	219	230	241	252
Residential	Smart water heating	0	0	8	16	24	26	31	39	51	66
Residential	Timed water heating	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Residential	TOU (Opt-out)	0	0	0	95	95	96	96	97	98	99
Residential	TOU - EV Charging (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	A/C DLC	36	36	36	34	33	33	34	34	34	34
Small C&I	Auto-DR (A/C)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Small C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Small C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Small C&I	Interruptible	15	15	15	15	15	15	15	15	15	15
Small C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Small C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	A/C DLC	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (HVAC)	11	45	56	64	72	72	73	74	75	76
Medium C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Medium C&I	CPP (Opt-in)	0	4	15	19	19	19	19	20	20	20
Medium C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Medium C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Medium C&I	Interruptible	14	14	14	15	17	18	19	20	22	23
Medium C&I	Thermal Storage	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-in)	0	0	0	0	0	0	0	0	0	0
Medium C&I	TOU (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (HVAC)	2	8	10	11	12	12	11	11	11	11
Large C&I	Auto-DR (Light Luminaire)	0	0	0	0	0	0	0	0	0	0
Large C&I	Auto-DR (Light Zonal)	0	0	0	0	0	0	0	0	0	0
Large C&I	CPP (Opt-in)	0	6	26	32	32	32	32	32	32	31
Large C&I	CPP (Opt-out)	0	0	0	0	0	0	0	0	0	0
Large C&I	Demand Bidding	0	0	0	0	0	0	0	0	0	0
Large C&I	Interruptible	56	56	56	55	55	54	53	52	51	50
Portfolio-Level Total		**309**	**359**	**411**	**543**	**570**	**585**	**603**	**624**	**649**	**677**

Notes:
Incremental load reduction available when DR programs are offered simultaneously as part of portfolio, accounting for overlap between programs.
No incremental potential is shown for residential air-conditioning load control, because NSP is transitioning it to the smart thermostat program.

BOSTON
NEW YORK
SAN FRANCISCO

WASHINGTON
TORONTO
LONDON

MADRID
ROME
SYDNEY

THE Brattle GROUP

IVVO 1.25%

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.57**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.87**

IVVO 1.25% - No Contingency

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	22
Other Benefits	19
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.61**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**571**
O&M Benefits	53
Other Benefits	222
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**

IVVO 1%

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.46**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.86**

IVVO 1% - No Contingency

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	18
Other Benefits	15
CAP Benefits	3
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.49**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**567**
O&M Benefits	53
Other Benefits	219
Customer Benefits	103
CAP Benefits	193
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.02**

IVVO 1.5%

NSPM -AMI- NPV

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(539)**
O&M Expense	(179)
Change in Revenue Requirements	(359)
Benefit/Cost Ratio	**0.83**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(79)**
O&M Expense	(5)
Change in Revenue Requirements	(74)
Benefit/Cost Ratio	**1.31**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(39)
O&M Expense	(2)
Change in Capital Revenue Requirement	(37)
Benefit/Cost Ratio	**0.67**

NSPM -AMI,FLISR, IVVOS- NPV

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(657)**
O&M Expense	(186)
Change in Revenue Requirement	(470)
Benefit/Cost Ratio	**0.88**

IVVO 1.5% - No Contingency

NSPM -AMI- ***NPV***

	Total ($MM)
Benefits	**446**
O&M Benefits	53
Other Benefits	203
CAP Benefits	190
Costs	**(452)**
O&M Expense	(146)
Change in Revenue Requirements	(306)
Benefit/Cost Ratio	**0.99**

FLISR

Benefits	**103**
O&M Benefits	0
Customer Benefits	103
Costs	**(67)**
O&M Expense	(4)
Change in Revenue Requirements	(63)
Benefit/Cost Ratio	**1.53**

IVVO

Benefits	27
Other Benefits	23
CAP Benefits	4
Costs	(37)
O&M Expense	(2)
Change in Capital Revenue Requirement	(34)
Benefit/Cost Ratio	**0.72**

NSPM -AMI,FLISR, IVVOS- ***NPV***

	Total ($MM)
Benefits	**575**
O&M Benefits	53
Other Benefits	226
Customer Benefits	103
CAP Benefits	194
Costs	**(556)**
O&M Expense	(152)
Change in Revenue Requirement	(404)
Benefit/Cost Ratio	**1.03**