BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF SOUTHWESTERN PUBLIC SERVICE COMPANY'S APPLICATION FOR AUTHORIZATION TO IMPLEMENT GRID MODERNIZATION COMPONENTS THAT INCLUDE ADVANCED METERING INFRASTRUCTURE AND RECOVER THE ASSOCIATED COSTS THROUGH A RIDER, ISSUANCE OF RELATED ACCOUNTING ORDERS, AND OTHER ASSOCIATED RELIEF,	)	**Case No. 21-00XXX-UT**
SOUTHWESTERN PUBLIC SERVICE COMPANY,	)	
APPLICANT.	)	

DIRECT TESTIMONY

of

STEVEN D. ROHLWING

on behalf of

SOUTHWESTERN PUBLIC SERVICE COMPANY

June 4, 2021

Case No. 21-00XXX-UT
Direct Testimony
of
Steven D. Rohlwing

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronym/Defined Term	**Meaning**
AGIS	Advanced Grid, Intelligence, and Security
AMI	Advanced Metering Infrastructure
BCR	Benefit to Cost Ratio
Brattle	The Brattle Group
CBA	Cost-Benefit Analysis
CMO	Customer Minutes Out
Commission	New Mexico Public Regulation Commission
CPP	Critical Peak Pricing
DCF	Discounted Cash Flow
EPRI	Electric Power Research Institute
FAN	Field Area Network
IT	Information Technology

MW	Mega watts
NPV	Net Present Value
NSPM	Northern States Power Minnesota
O&M	Operation and Maintenance
PSCo	Public Service Company of Colorado
PUCT	Public Utility Commission of Texas
SPS	Southwestern Public Service Company, a New Mexico corporation
TOU	Time of Use
WACC	Weighted Average Cost of Capital
WiSUN	Wireless Smart Utility Network
Xcel Energy	Xcel Energy Inc.
XES	Xcel Energy Services

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LIST OF ATTACHMENTS

Attachment	**Description**
SDR-1	AMI Cost-Benefit Analysis Summary
SDR-2	FLISR Cost-Benefit Analysis Summary
SDR-3	Summary of Cost-Benefit Analysis Results
SDR-4	PSCo Brattle Load Flexibility Study
SDR-5	NSPM Brattle Load Flexibility Study
SDR-6	AMR Cost-Benefit Analysis Summary

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Steven D. Rohlwing. My business address is 1800 Larimer Street, Denver, Colorado 80202.

Q. On whose behalf are you testifying in this proceeding?

A. I am filing testimony on behalf of Southwestern Public Service Company, a New Mexico corporation ("SPS"), and wholly-owned subsidiary of Xcel Energy Inc. ("Xcel Energy").

Q. By whom are you employed and in what position?

A. I am employed by Xcel Energy Services Inc. ("XES"), the service company subsidiary of Xcel Energy, as Manager, Asset Risk Management.

Q. Please briefly outline your responsibilities as Manager, Asset Risk Management.

A. I am responsible for asset risk management, risk analytics, and modeling.

Q. Please describe your educational background.

A. I graduated from University of Colorado - Boulder in 1994 with a bachelor's degree in mathematics and a bachelor's degree in secondary education. In 2012, I received my Masters Degree in Business Administration from the University of

Colorado – Denver. I am currently pursuing a masters in Business Analytics from the University of Colorado - Denver.

Q. Please describe your professional experience.

A. I joined Xcel Energy in 2003 and have held positions in Asset Risk Management, Business Area Finance, and Risk Analytics. I have been in my current position since 2018.

Q. Have you testified before any regulatory authorities?

A. Yes. In 2020-2021, I testified before the Colorado Public Utilities Commision in a rider proceeding filed by Public Service Company of Colorado ("PSCo") (Case No. 20A-03-00E) regarding recovery for electric services associated with PSCo's Wildfire Mitigation Plan.

II. PURPOSE AND SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my direct testimony is to present SPS's overall assessment of the costs and quantifiable benefits of the future components of its Grid Modernization initiative. I present the conservative structure of SPS's overall Benefit to Cost Ratio ("BCR"), which is provided in Table SDR-1 to my direct testimony, and explain that the Cost-Benefit Analysis ("CBA") model is one tool to utilize for the assessment of the quantifiable costs and benefits of SPS's overall plans for the Grid Modernization initiative. I support specific types of customer benefits in the model. Additionally, I summarize several qualitative benefits that are difficult to quantify.

Q. Please summarize your conclusions and recommendations.

A. My testimony supports SPS's CBA model for the Grid Modernization initiative. I conclude that SPS's model is a reasonable methodology of assessing quantifiable costs and benefits of SPS's proposal. The benefits included in SPS's CBA model focus on the distribution level for residential and C&I customers.At this time, the benefits addressed in the model do not include transmission level benefits.

Notwithstanding, the model shows that SPS's implementation of grid modernization components will benefit SPS's New Mexico retail customers.

Overall, I explain why the model is appropriate and provides a reasonable comparison of the costs and benefits of the future components of the Grid Modernization initiative from the customer perspective. The model has some limitations, in that it only includes costs and benefits that SPS has quantified and monetized. Some benefits (customer satisfaction, for example) are not quantified, and SPS did not determine a cost basis for human safety benefits. As such, the model is one tool to conservatively assess SPS's proposal from the customer's point of view, but it under-states the value of the customer benefits.

The model results in estimated BCR for each component, as well as the composite ratio for the overall initiative. A ratio of 1.0 or higher indicates the net present value ("NPV") over the life of the project of quantifiable benefits are expected to equal to or exceed the NPV of the quantifiable costs of the same timeframe. A ratio of less than 1.0 indicates the exact opposite: the NPV of the quantifiable costs over the life of the project are expected to exceed the NPV of the quantifiable benefits over that same timeframe. Table SDR-1 provides the BCRs for Advanced Metering Infrastructure ("AMI") and Fault Location, Isolation, and Service Restoration ("FLISR") as well as for the combined Grid Modernization program. Because the Field Area Network ("FAN") supports AMI and FLISR, SPS did not conduct a separate benefit to cost analysis for FAN.

Table SDR-1: Grid Modernization Benefit-Cost Ratios[1]

Component	Baseline BCR
AMI	1.10
FLISR	1.44
Overall Grid Modernization	**1.15**

Overall, I conclude that SPS's benefit to cost ratio demonstrates more benefit than cost for the customer over the life of the project, even before considering additional, unquantified benefits.

Q. Were Attachments SDR-1 through SDR-3 and SDR-6 prepared by you or under your direct supervision and control?

A. Yes.

Q. Are Attachments SDR-4 and SDR-5 true and correct copies of the studies prepared by the Brattle Group?

A. Yes.

[1] The benefit-cost ratios include FAN and contingencies and exclude Critical Peak Pricing ("CPP"), which is discussed later in my testimony.

III. GRID MODERNIZATION QUANTITATIVE COST-BENEFIT MODEL

A. Model Structure and Requirements

Q. Why did SPS conduct a CBA in this case?

A. SPS is presenting its CBA to aid the New Mexico Public Regulation Commission ("Commission") and other stakeholders in evaluating the overall prudency of SPS's application.

Q. Please introduce the cost-benefit model.

A. The CBA model compares the quantifiable costs with the quantifiable benefits of each component of SPS's Grid Modernization initiative, as well as the quantifiable costs and quantifiable benefits of the overall initiative. Note that as I further explain the specifics of the BCR, when I refer to costs or benefits, they are the quantifiable costs and quantifiable benefits. 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 Grid Modernization initiative. The sources of the CBA's data, estimates, and assumptions were provided by SPS witnesses Ruth M. Sakya, Chad S. Nickell, and Michael O. Remington.

The CBA model utilizes the Discounted Cash Flow ("DCF") formula and the 2021 NPV for costs and benefits, to determine the value of the Grid

Modernization investments. Specifically, the BCR evaluates the standalone costs and benefits of AMI and FLISR, as well as the FAN costs allocated to each of these components. Finally, the model evaluates the NPV BCR for AMI and FLISR on a combined basis.

Q. How was the cost-benefit analysis model developed?

A. The structure and methodology of the CBA was based on Ameren Illinois business case, which was accepted in 2012 by the Illinois Commerce Commission in Docket No. 12-0244, and is consistent with Xcel Energy's general approach to CBAs, including the CBA provided to the Colorado Public Utilities Commission in PSCo's Advanced Grid, Intelligence, and Security ("AGIS") Certificate of Public Convenience and Necessity proceeding (that matter, Proceeding No. 16A-0588E, resulted in an unopposed settlement approving PSCo's need for the components of AGIS), and the CBA provided to the Minnesota Public Utilites Commission in the Northern States Power Company of Minnesota ("NSPM") AGIS Certificate of Public Necessity proceeding (certification was approved in Docket No. E002/GR-19-564). In addition, in structuring the CBA for grid modernization investments, I reviewed similar analyses conducted by other companies and considered the Electric Power Research Institute's ("EPRI") technical report on Estimating the Costs and Benefits of the Smart Grid.[2]

Q. Why did SPS select this form of quantitative model?

A. A cost-benefit analysis is a simple, straight-forward, and generally accepted methodology comparing the benefits and costs of the Grid Modernization components from the customer's position, allowing for a clear understanding of the value of a program or initiative with the ability to compare alternatives. Nevertheless, this CBA is only one aspect of a more extensive assessment performed by SPS prior to seeking Commission approval for AMI, FLISR, and FAN presented in this case. The more robust assessment includes evaluation of the needs and goals of the electric system, customers, the Commission, the New Mexico Legislature, and other stakeholders. Alternatives were also considered to meet those needs and goals and are described in detail in the testimony of Mr. Nickell and Mr. Remington. For example, Mr. Nickell and Mr. Remington explain the extensive planning, information gathering, Request for Proposal processes, and consideration of alternate vendors, devices, systems, and programs

[2] https://www.epri.com/research/products/1020342.

that SPS undertook prior to selecting its proposed AMI plan.[3] The CBA demonstrates the cost-effectiveness of AMI and FLISR, that includes FAN costs, as well as the total Grid Modernization initiative.

Q. How did SPS structure the CBA presented in your testimony?

A. The model compares the upfront and ongoing component implementation costs (including planning and installation) against the benefits over the analysis period. The model incorporates the Electric Distribution costs of the systems and the Business Systems costs required for the implementation of the components including: integration, software-hardware, project management, and other Information Technology ("IT") costs.

The model views costs and benefits from the customer perspective. The CBA quantifies the estimated net impact of costs and savings to customers. In this respect, all quantifiable utility costs and benefits were estimated in the model as they would be effectuated through utility electric rates. For example, SPS estimated the total cost of meter installation and operation in terms of revenue requirements.

[3] 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.

The benefits are the estimated direct customer benefits. These benefits vary, 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 ("TOU") rates; reduced outage impacts to customers' own activities; and avoidance of lost revenue through meter tampering.

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 SPS New Mexico's weighted average cost 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.

Second, for operation and maintenance ("O&M") costs and savings, fuel savings, and other benefits, the model assumes that costs and benefits are expensed or realized in the year incurred, and thus embedded in SPS's electric rates, flowing through to customers.

Q. How does the model convert the estimates of net capital revenue requirement, O&M costs, and benefits to a BCR?

A. Once the stream of the net capital revenue requirements, O&M costs, and O&M benefits are calculated for the life of the project (20 years), the NPV (to 2021) of each stream is determined utilizing SPS's WACC as the discount rate. The NPV of benefits divided by the NPV of costs creates the BCR. A BCR of 1.0 indicates the benefits for the customer of that specific component of the Grid Modernization initiative equal the costs to the customer; a ratio of less than 1.0 indicates costs exceed benefits; and a ratio greater than 1.0 indicates benefits exceed costs.

Q. Please describe the period of time the model examines.

A. The models for AMI and FLISR examine the period beginning in 2021 and ending 2042.

Q. Why does the model examine these periods of time?

A. For AMI, the model reflects the current phase of work beginning in 2021, and future installation phases beginning in 2022, as described by Mr. Nickell. 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.

While AMI meters begin installation ending in 2022, and FLISR assets 2023, respectively, the IT components of both will need to be in place by the time of the initial deployment in order for the systems to function. SPS has utilized a twenty-year depreciation period for AMI, FLISR, and communication components, which is consistent with industry expectations.

Q. Please provide more information on how SPS developed the cost and benefit inputs into the model.

A. The costs and benefits for both capital and O&M of AMI and FLISR, including the associated FAN components, were determined by Customer Care, Business

Systems, and Electric Distribution areas (including business area financial teams), with additional support from the AGIS Program Management Office, as discussed in more detail below. The Program Management Office, Risk Management, and Regulatory Departments coordinated and developed modeling assumptions consistent with these cost and benefit estimates. The testimonies of Ms. Sakya, Mr. Nickell, and Mr. Remington provide detail regarding the cost and benefit assumptions for AMI, FLISR, and FAN (which enables the benefits provided by AMI and FLISR). I summarize those model inputs and provide explanations on the overall CBA results.

Q. Why do you refer to AMI and FLISR costs and benefits as "including the associated FAN components"?

A. As Mr. Nickell and Mr. Remington explain in their direct testimony, the FAN will be a single, general-purpose, field area wireless networking resource that enables two-way communication between the existing infrastructure at SPS's data centers, SPS's substations, and the new and planned field devices up-to and including the customer meter. The FAN provides the necessary communication capacity for the implementation of AMI and FLISR, while ensuring the data being transmitted is secure. FAN is not a standalone program and does not provide benefits on its own; rather, it is the communications network to enable AMI and FLISR functionality, providing respective benefits to customers. As such, FAN costs have been incorporated into the CBA models for AMI and FLISR.

Q. How were the FAN components incorporated into the model?

A. FAN costs were allocated across the analyses for the individual Grid Modernization components. Specifically, as explained by Mr. Remington, the FAN structure is primarily made up of two technological modules: cell-modem technology and the Wireless Smart Utility Network ("WiSUN"). WiSUN is a low-rate wireless system that must be in place to enable AMI device-to-device and device-to-headend communication. AMI is the predominant beneficiary of the WiSUN system; therefore, WiSUN costs have been completely allocated to AMI.

The meters and repeaters that constitute the AMI and the FLISR reclosers will each have embedded communication modules that will allow them to communicate directly with the FAN's access points.

AMI and FLISR assume implementation of the FAN from 2022-2025, consistent with the timeline to subsequently implement the AMI meters and FLISR assets.

Q. Please provide more detail as to how the IT components are incorporated into the model.

A. As described by Mr. Remington, IT efforts include the costs of integrating the components of the Grid Modernization initiative with existing SPS 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 Grid Modernization programs. Therefore, the costs of IT efforts for AMI and FLISR are included in the cost-benefit model for these components.

Q. How were the model's cost and benefits inputs determined for the first five-year period, from 2021 through 2025?

A. Each subject matter expert provided estimated costs and benefits for both capital and O&M for the period 2021 through 2025. These costs were provided in nominal dollars over this period. Benefits for both capital and O&M were provided in 2021 dollars and converted to nominal dollars for this period.

Q. How were the model's cost and benefits inputs determined for 2026 through 2042?

A. The additional O&M costs beyond 2025 were estimated for each respective part of the project through 2042 for AMI and FLISR, in order to capture the costs and benefits of each of the components beyond the initial implementation period. These O&M costs were provided in 2021 dollars and converted to nominal dollars for the full twenty-year analysis period.

Benefits were also estimated for this period based on when customers are expected to realize these benefits through 2042.

Q. How are the costs in the model categorized?

A. The costs in the model are from several perspectives and are identified in Attachments SDR-1 and SDR 2 as:

- rate case budgets, to the extent they are longer-range planning costs for the years after 2021;
- capital or O&M;
- Business Systems or Electric Distribution costs; and
- direct, indirect, tangible, or intangible costs.

Q. Are internal and external labor costs included in the costs of each component of the Grid Modernization initiative included in the model?

A. Yes. Both the model and the overall support for the Grid Modernization initiative in this proceeding capture the "all-in" costs of the Grid Modernization components.

Q. Do the cost inputs for AMI and FLISR include contingency assumptions?

A. Yes. In addition to the cost estimates, the Electric Distribution and Business Systems areas developed contingency estimates for each component that warranted a contingency. These contingency estimates are depicted on page 1 of Attachment SDR-1 (AMI CBA Summary) and page 1 of Attachment SDR-2 (FLISR CBA Summary) as cost line items. Since, by definition, the amount and type of contingency dollars that will be spent cannot be defined up front with certainty, SPS included a range of result analysis for each component both with and without contingency dollars, providing insight into how the potential contingency amounts affect the overall BCR. Mr. Nickell and Mr. Remington 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 component and input into the model as a cost. In essence, the model evaluates the cost of the project as if SPS needed to spend up to the full contingency amounts.

Q. What steps did SPS undertake to ensure that the model is structurally sound?

A. As I have discussed, the model methodology was based on Ameren Illinois business case, which was accepted by the Illinois Commerce Comission, and similar analyses undertaken by Xcel Energy and other utilities in support of similar AMI and grid advancement programs. A number of business areas within Xcel Energy, including Regulatory Administration, Risk, Corporate Development, Capital Asset Accounting, Revenue Requirements, Demand Side Management, Business Systems, and Electric 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 Grid Modernization initiative?

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

The CBA model also provides a high-level look at the costs versus the benefits of the overall Grid Modernization initiative for customers, as well as a more detailed breakdown of individual costs and benefits assumptions for each program. Nevertheless, the CBA model does not include all aspects for undertaking the Grid Modernization program. Some benefits of the program cannot be quantified or monetized.

Q. Please further describe unquantified or unmonetized benefits.

A. The CBA is, by definition, intended to quantify costs and benefit and thus, 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, improved quality of service delivered, and safety, among others described by Ms. Sakya, Mr. Nickell, and Mr. Remington.

Q. How do unquantified or unmonetized benefits impact the BCR?

A. As a practical matter, the BCR resulting from the CBA provides an extremely conservative look with a BCR that is lower than what would fully reflect the actual benefits customers will derive.

In addition, a model based on measureable considerations does not take into account any fundamental need for the infrastructure in question. For example, SPS requires meters in order to provide and bill for electric service. A cost-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 SPS considered the costs of AMI versus AMR technology as a BCR comparison alternative, that comparison cannot fully assess whether it would be short-sighted or impracticable for SPS to replace an aging manual reading procedure with other aging technology, nor the effect of using older technology on unquantifiable customer expectations (better outage and service restoration communications, and more timely energy consumption data) that is more dependent on advanced metering technology. Overall, the model is a helpful assessment tool within the scope of its intended purpose.

B. Quantitative Inputs

1. AMI Inputs

Q. What are the key costs and benefits of AMI?

A. Mr. Nickell discusses the costs and benefits of AMI in detail in his 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, and pricing flexibility; (ii) reducing field and meter service and meter reading costs; (iii) reducing unaccounted for energy; (iv) assisting with identification of service outages and fostering restoration; (v) providing voltage measurement information to assist in load flow and voltage calculations; (vi) serving as signal repeaters for other AMI meters and FAN network components; and (vii) improving infrastructure investment efficiencies. As discussed below, not all of the benefits of AMI are quantifiable or able to be monetized.

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

Q. How were AMI capital cost and benefit inputs derived for purposes of the CBA model?

A. Capital and O&M cost and benefit estimates for the AMI program were developed by SPS subject matter experts and are detailed in the Direct Testimonies of Mr. Nickell and Mr. Remington, as set forth in Tables 2 through 6 below. Attachment SDR-1 provides a summary of each component of the quantifiable AMI costs and benefits, as they appear in the CBA.

Table SDR-2: AMI Capital Costs

Capital Cost	Description	Supporting Witness
Meters and Installation	Capital costs portion of AMI meter purchase and installation. Capital costs of both internal and external support personnel.	Nickell
Field Area Network (AMI)	Capital costs associated with implementation of the WiSUN network and associated assets.	Remington
	Capital costs associated with installation of pole-mounted devices.	Nickell
IT Systems and Integration	Capital costs associated with the various IT infrastructure and integration in support of AMI.	Remington
Program Management	Capital costs associated with internal management	Nickell

Capital Benefit	Description	Supporting Witness
Distribution System Management Efficiency	More efficient use of capital dollars to maintain the distribution system.	Nickell
Outage Management Efficiency	Improved capital spend efficiency during outage events.	Nickell
Avoided Meter Purchases for Failed Meters	AMI meters have a lower failure rate as compared to standard meters. By purchasing new AMI meters, SPS avoids the need to replace failing standard meters.	Nickell
Avoided meter reading costs	Avoided capital derived from vehicles and other equipment costs	Nickell

Q. How were AMI O&M cost and benefit inputs derived for purposes of the CBA model?

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

Table SDR-4: AMI O&M Costs

O&M Benefit	Description	Supporting Witness
Avoided O&M Meter Reading Cost	Avoided O&M cost derived from labor and fleet costs savings.	Nickell
Reduction in Field and Meter Services	Reduction in O&M costs related to addressing meter and outage complaints and connections.	Nickell
Improved Distribution System Spend Efficiency	Increased efficiency of distribution maintenance costs.	Nickell
Outage Management Efficiency	Improved O&M efficiency during outage events.	Nickell

Table SDR-5: Other Quantifiable AMI Benefits

Benefit	**Description**	**Supporting Witness**
Reduction in Energy Theft	Easier identification of energy theft and an associated reduction in the amount of theft.	Nickell
Reduced Consumption Inactive Premise	Expedited ability to turn off power quickly when determined premise has been vacated.	Nickell
Reduced Uncollectible/Bad Debt	Decreased loss due to uncollectible/bad debt.	Nickell
Reduced Outage Duration	Direct benefit to customers associated with reduced outage duration.	Nickell
CPP	Customer demand savings in response to new rate structures.	Rohlwing
TOU Customer Price Signals	Difference in energy prices paid by consumers in response to new rate structures.	Rohlwing

Q. Please summarize the benefits you describe in your testimony.

A. As noted in Table 5 above, I discuss how SPS calculated AMI benefits associated with TOU customer price signals (combined, "load flexibility" benefits) for purposes of the CBA.

Q. Please provide additional information regarding SPS's load flexibility assumptions.

A. The CPP benefit is not included in the base case CBA, although it is a potential benefit that can be implemented in the future. The TOU benefit is included in the base CBA. SPS engaged The Brattle Group ("Brattle") to model likely customer response to TOU and CPP rates. The Brattle Group developed load flexibility studies for PSCo and NSPM, both Xcel Energy operating companies. Both studies are provided in Attachments SDR-4 and SDR-5, respectively. The NSPM study entitled "The Potential for Load Flexibility in Xcel Energy's Northern States Power (NSP) Service Territory" was selected as the most conservative and suitable research to reproduce New Mexico's estimates. The Brattle Study developed the quantification of the benefits of potential TOU and CPP rates, which were incorporated into the CBA. Using 2021-2042 annual sales forecasts for both SPS and NSPM, SPS built a residential load percentage relation between the two, and estimated the potential equivalent TOU and CPP values associated with SPS New Mexico's residential customers. Further, SPS utilized residential load projections to estimate shifting demand from on-peak to off-peak periods, resulting in energy price savings for residential customers.

Q. Why did SPS rely on the Brattle Study?

A. Brattle is a well-respected economic consulting and analytics firm, and conducted a similar study for PSCo and NSPM. Their studies produce robust, reasonable, and generally accepted results.

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. Demand reduction grows modestly as TOU adoption and utilization expands. Based on these assumptions and the base case in the Brattle analysis, the potential to shift demand in New Mexico is estimated as 21 megawatts ("MW") for residential customers from on-peak to off-peak. The overall result is cost savings to customers.

Q. What potential benefits are associated with CPP?

A. The potential CPP rate "provides customers with a much higher rate during peak hours on 10 to 15 days per year." 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 21 MW for residential customers in New Mexico under the base case scenario.

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 identifies those differentiating features, each of which is intended to enhance the reliability and sophistication of the analysis. SPS 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 SPS'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 Ms. Sakya and Mr. Nickell, SPS proposes 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."[4] 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. Customers who opt out would incur a one-time fee and a monthly charge to cover the cost of meter reading. These charges would be established in an amount that offsets the costs of opting out, so there is no direct material net cost impact to the CBA.

Q. How were these changes to customer price signals translated to benefits in the Grid Modernization AMI CBA?

A. SPS 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

[4] NSPM Brattle Study at p. 31.

peak to off-peak was then multiplied by the difference in the Southwest Power Pool Hub on and off-peak price forecasts filed with SPS's Integrated Resource Plan (Case No. 18-00215-UT). This estimates the savings in energy prices customers will experience in shifting their demand from on to off-peak.

2. FLISR Inputs

Q. What are the key benefits of FLISR?

A. Mr. Nickell discusses the purpose and benefits of FLISR in detail in his direct testimony. In short, the purpose of FLISR is to reduce the duration and impact of outages on SPS's customers.

Q. How were FLISR cost and benefit inputs derived for purposes of the CBA model?

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. Capital and O&M cost and benefit estimates for the FLISR program (including contingencies) are detailed in the Direct Testimony of Mr. Nickell and Mr. Remington, as set forth in Tables 6 through 8 below. FLISR's 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 Attachment SDR-2 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 6, below.

Table SDR-6: Capital Costs of FLISR

O&M Cost	Description	Supporting Witness
Assets and Installation	O&M costs of the FLISR devices and installation.	Nickell
Field Area Network (FLISR)	O&M costs associated with implementation of the WiSUN network and associated assets.	Remington
IT Systems and Integration	O&M costs associated with the various IT infrastructure and integration in support of FLISR.	Remington

Q. How were FLISR O&M inputs derived for purposes of the CBA model?

A. FLISR O&M costs and benefits were developed by Mr. Nickell and Mr. Remington as set forth below:

Table SDR-7: O&M Costs of FLISR

Capital Cost	Description	Supporting Witness
Assets and Installation	Capital costs of the FLISR devices and installation, including both internal and external support	Nickell
Field Area Network (FLISR)	Capital costs associated with implementation of the WiSUN network and associated assets.	Nickell

Table SDR-8: Other Quantifiable FLISR Benefits

Benefits	Description	Supporting Witness
Customer Minutes Outage – Savings	Benefits to customers associated with reduced outage duration	Nickell

Q. Please summarize the capital expenditures associated with AMI, FAN, and FLISR for the time period 2022-2025?

A. The summary of capital expenditures associated with AMI, FAN, and FLISR, which I received from Mr. Nickell and Mr. Remington, is shown in Table SDR-9, below.

Table SDR-9: Grid Modernization- Capital Expenditures (New Mexico Retail -$MM)

Component	2022	2023	2024	2025
AMI	5.42	17.08	0.87	0.05
FLISR	0.00	2.10	2.47	0.50
FAN	0.69	1.66	0.79	0.12
Total	**6.11**	**20.84**	**4.13**	**0.67**
*There may be differences between the sum of the individual project amounts and total amounts due to rounding.				

Q. Please summarize the O&M costs associated with AMI, FAN, and FLISR for the time period 2022-2025.

A. The summary of O&M costs associated with AMI, FAN, and FLISR, which I received from Mr. Nickell and Mr. Remington, is shown in Table SDR-10, below.

Table SDR-10: Grid Modernization- O&M Expenditures (New Mexico Retail -$MM)

Component	2022	2023	2024	2025
AMI	0.29	1.30	1.38	1.13
FLISR	0.00	0.09	0.28	0.24
FAN	0.12	0.19	0.41	0.33
Total	**0.41**	**1.58**	**2.07**	**1.70**
*There may be differences between the sum of the individual project amounts and total amounts due to rounding.				

Q. What other costs are included in the CBA?

A. The summary of other AMI, FAN, and FLISR O&M costs are shown in Table SDR-11. These costs are associated with internal labor, which I received from Mr. Nickell and Mr. Remington.

Table SDR-11: Grid Modernization- O&M Other Expenditures (New Mexico Retail -$MM)

Component	2022	2023	2024	2025
AMI	0.07	0.16	0.06	0.02
FLISR	0.00	0.02	0.08	0.13
FAN	0.19	0.11	0.15	0.17
Total	**0.15**	**0.29**	**0.28**	**0.32**
*There may be differences between the sum of the individual project amounts and total amounts due to rounding.				

Q. Overall, how would you characterize the cost and benefit budgeting assumptions in this model for each component of the Grid Modernization initiative?

A. Particularly for the modeling results that include 100 percent of SPS's planned contingencies, I would characterize this model as a conservative representation of estimated costs and benefits. Because AMI and FLISR are still in their early phases, the contingencies represent early estimates of potential additional costs. Likewise, SPS 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. The goal is to represent a conservative but realistic analysis to support the Commission's review of SPS's CBA model for the Grid Modernization initiative.

C. CBA Results

Q. Please summarize the quantitative cost and benefit comparison for the AMI program.

A. Table SDR-12 summarizes the results of SPS's evaluation of AMI.

Table SDR-12: AMI BCR
(Excludes CPP Benefits)

NM FLISR- NPV	Total ($MM)
Benefits	46
O&M Benefits	34
Other Benefits	10
CAP Benefits	1
Costs	(41)
O&M Expense	(10)
Change in Revenue Requirements	(31)
Benefit/Cost Ratio	1.10

There may be differences between the sum of the individual components and the total amounts and calculations due to rounding. Attachment SDR-1 provides more detail regarding the results of SPS'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 BCR basis, AMI is expected to have a minimum BCR of approximately 1.10 with full contingencies and excluding CPP benefits. AMI is expected to have a maximum BCR of approximately 1.51 with CPP and no contingencies. In terms of NPV, the 1.10 BCR which includes all contingencies, but no CPP benefit, indicates approximately $5 million ($46-$41) in benefits to customers over 20 years.

Q. Please summarize the quantitative cost and benefit comparison for the FLISR program.

A. Table SDR-13 summarizes the results of SPS's evaluation of FLISR:

Table SDR-13: FLISR BCR

NM FLISR- NPV	**Total ($MM)**
Benefits	8
O&M Benefits	0
Customer Benefits	7
Costs	(6)
O&M Expense	(1)
Change in Revenue Requirements	(5)
Benefit/Cost Ratio	1.44

There may be differences between the sum of the individual components and the total amounts and calculations due to rounding. Attachment SDR-2 provides more detail regarding the results of SPS'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 BCR basis, FLISR benefits are expected to exceed FLISR cost, with an expected BCR of approximately 1.44 with full contingencies to 1.51 with no contingencies. In terms of NPV, the 1.44 BCR indicates approximately $2 million in benefits to customers over 20 years.

Q. Do you also provide a combined summary of the costs and quantitative benefits of the Grid Modernization components?

A. Yes. To determine the combined BCR for the Grid Modernization initiative, four different categories are identified and aggregated: O&M, Capital, Customer, and Other benefits. Also, there are two types of costs of each component: O&M and Capital (as a change in revenue requirements). The final combined ratio is the result of dividing the aggregated benefits by the aggregated costs. Table SDR-14 summarizes the results of SPS's evaluation of the combined AMI/FLISR program:

Table SDR-14: Grid Modernization Initiative Combined BCR (Excludes CPP)

<u>**NM -AMI, FLISR-NPV**</u>	**Total ($MM)**
Benefits	54
O&M Benefits	34
Other Benefits	10
Customer Benefits	8
Capital Benefits	1
Costs	(47)
O&M Expense	(11)
Change in Revenue Requirement	(36)
<u>**Baseline BCR**</u>	1.15

Attachment SDR-3 to my direct testimony provides the overall relative costs and benefits of the Grid Modernization initiative.

Q. What do you conclude regarding the overall quantitative outcomes of the Grid Modernization CBA?

A. On a combined basis, the quantifiable benefits of AMI and FLISR are expected to be higher than program costs, with an expected BCR of approximately 1.15 for the most conservative scenario and 1.51 including CPP benefits and no contingencies. These totals represent a simple combination of AMI and FLISR respective costs and benefits, inclusive of the costs attributable to that portion of the FAN needed to enable AMI and FLISR presented on a NPV basis.

In the next section, I address other cost and benefit considerations that factor into the overall prudence of SPS's proposed Grid Modernization initiative.

IV. LEAST-COST/BEST-FIT ANALYSES

Q. Did SPS also develop any least-cost/Best-Fit analyses to compare metering alternatives?

A. Yes. Table SDR-15 summarizes the results of SPS's evaluation of two options, as compared with SPS's current manual meters. 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.

Table SDR-15: Meter Reading Least-Cost Best-Fit Alternative

		Alternative		
Item	**Description**	**Manual**	**AMR Drive-By**	**AMI**
Meter Capabilities	Time of use data	◔	◔	●
	Real time notification of power outages	○	○	●
	Fast response to customers inquires	○	○	●
	Support integrated systems that offer customers	○	○	●
	Vehicle to grid interconnects	○	○	●
	Remote reconfiguration/ firmware updates	○	○	●
	Availability of real time data	○	○	●
	Availability of power quality events	○	○	●
	Remove availability of meter diagnostic data	◔	◔	●
	Remote disconnect/ connect	○	○	●
	Detect unsafe field metering conditions	○	○	●
	Energy Theft	◔	◔	●
	Support for advanced rates	○	○	●
	Support for ADMS	○	○	●
Operational Features	Time consuming activity	A	NA	NA
	Labor intensive - Safety Concerns	A	PA	NA
	Cost of paying someone to read the meters.	A	PA	NA
	Need access to meters to read them.	A	NA	NA
	Accuracy of the meter read, human error.	A	NA	NA
	Usually carried out infrequently (monthly).	A	PA	NA
	Doesn't usually match invoice billing period.	A	PA	NA
	Cost of system maintenance	NA	A	A
	Relying on technology	NA	A	A
NPV (2021)	Calculated COSTS - CAP Change in RR and O&M		$39M	$41M
	BENEFITS-Incremental to current reading/ billing		$19M	$46M
	NET COST-OUTCOME		**$(20)M**	**$5M**
Least-Cost, Best-Fit Alternative Selected				**AMI System**

Legend for Capabilities

Full	Most	Partial	Minimal	None
●	◕	◑	◔	○

Legend for Operational Features

Non-Applicable	Applicable	Partially Applicable
NA	A	PA

Q. How did you calculate the costs and benefits of the AMR solution for purposes of this Least-Cost/Best-Fit analysis?

A. The AMR Drive-by quantifiable cost and benefit estimates were provided by the metering department. 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 SPS's current meter reading system. On a total resource BCR basis, AMR is expected to have a BCR of approximately 0.50. Table SDR-16 summarizes the results of SPS's evaluation of AMR, and Attachment SDR-6 provides more detail regarding the results of SPS's analysis of AMR.

Table SDR-16: AMR BCR

NM AMR- NPV	**Total ($MM)**
Benefits	19
O&M Benefits	18
Customer Benefits	1
Costs	(39)
O&M Expense	(12)
Change in Revenue Requirements	(27)
Benefit/Cost Ratio	0.50

Q. What does this Least-Cost/Best-Fit Analyses show?

A. The analyses provide another means (in addition to the CBA and the extensive narrative testimony) of comparing the Grid Modernization solutions with alternatives.

V. QUALITATIVE BENEFITS OF GRID MODERNIZATION

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. A number of benefits of AMI 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. The analysis captures estimates of customer adoption of technologies to support customer options 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 benefits SPS did not model in the CBA 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 SPS employees;

- improvements in power quality; and
- cyber and data security.

These benefits are discussed by Ms. Sakya, Mr. Nickell, and Mr. Remington.

Q. Does the FLISR program provide benefits to customers or the distribution system that were not modeled in your analysis?

A. Yes. As with AMI, there are benefits of FLISR that SPS 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. Why didn't SPS attempt to quantify these benefits?

A. Although SPS feels strongly that these benefits are meaningful to its 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 SPS's business model and role as a public utility, but do not easily lend themselves to monetization.

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

Q. Aside from the CBA, are AMI and FLISR valuable resources that warrant cost recovery?

A. Yes. Firstly, the AMI and FLISR implementation will allow SPS to achieve greater visibility into its distribution system, providing greater opportunities for demand side management and improved reliability. Conversely, SPS cannot make the same progress in these areas without enhancing the distribution grid. Right now, SPS simply does not have the technical capability or insight into customer usage to implement such technologies or customer support without AMI and FLISR.

Secondly, the quantifiable benefits exceed costs for all AMI circunstances. Further, the model cannot fully reflect that manual and/or AMR meter reading 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 Distributed Energy Resources ("DER").

Thirdly, the 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. Choice, convenience, and greater control over energy costs and usage are of increasing importance to SPS's customers. Customer satisfaction and customer empowerment with respect to their energy choices are of central importance to the public utility model.

Finally, SPS's witnesses describe at length why it is important to advance the SPS grid to continue providing safe, increasingly reliable electric service to its customers not just in the present but also into the future. The Grid Modernization initiative will support a fundamental utility function while improving existing infrastructure that is no longer maximizing service to its customers. It makes future applications, optionality, and DER available in a way it is not possible to fully measure because it is not possible to fully predict the future. Utilities nationwide are making these important grid investments because "doing nothing" is not a realistic option. Therefore, SPS feels that this is the right time to modernize critical components of its distribution grid and the proposed Grid Modernization provides the most benefit to customers for the cost.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

VERIFICATION

On this day, June 4, 2021, I, Steven D. Rohlwing, swear and affirm under penalty of perjury under the law of the State of New Mexico, that my testimony contained in Direct Testimony of Steven D. Rohlwing is true and correct.

/s/ Steven D. Rohlwing
STEVEN D. ROHLWING

Southwestern Public Service Company

AMI Cost-Benefit Analysis

1	COSTS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	TOTAL	NPV
2	*Total Meters Deployed*	*0*	*20,000*	*102,000*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*122,000*	
3	**CAPITAL COSTS**																							*TOTAL*	*NSPM-PV*
4	**AMI Meters**																								
5	AMI Meters Purchase	0	4,246,587	9,807,393	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	14,053,980	11,809,833
6	AMI Meter Installation	0	533,334	2,746,670	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3,280,004	2,731,069
7	Vendors deployment Project Management	0	116,143	232,287	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	348,430	293,390
8	AMI Operations (Internal Personnel)	0	266,289	266,289	353,427	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	886,005	726,223
9	AMI Operations (External Personnel)	0	128,776	457,375	76,734	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	662,885	549,144
10	Customer Communication and Education	0	92,656	122,404	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	215,060	182,241
11	Distribution Contingencies	0	0	2,900,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2,900,000	2,388,721
12	*TOTAL - AMI Meters*	0	5,383,785	16,532,418	430,161	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*22,346,364*	*18,680,622*
13	**Communications**																								
14	Construction Contractor	0	0	98,000	194,000	90,283	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	382,283	295,861
15	Itron	0	485,000	790,000	100,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,375,000	1,154,107
16	Labor	0	90,221	325,200	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	415,421	347,144
17	Materials	0	118,316	185,510	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	303,826	256,770
18	Overheads	3,311	0	30,000	123	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	33,434	27,910
19	Network Contingency	0	0	226,614	500,113	27,085	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	753,811	592,416
20	*TOTAL - Communications*	*3,311*	*693,537*	*1,655,324*	*794,236*	*117,368*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*3,263,775*	*2,674,208*
21	**IT Systems and Integration**																								
22	IT Software	0	0	323,589	323,589	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	647,177	516,391
23	Contract Labor	0	0	187,542	85,958	46,886	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	320,386	254,784
24	IT Contingency	91,040	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	91,040	85,340
25	*TOTAL - IT Systems and Integration*	*91,040*	*0*	*511,131*	*409,547*	*46,886*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1,058,603*	*856,516*
26	**Program and Project Management Costs**																								
27	Security and Testing	153,295	39,570	48,037	26,419	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	267,322	238,436
28	*TOTAL - Program Management*	*153,295*	*39,570*	*48,037*	*26,419*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*267,322*	*238,436*
29	**TOTAL CAPITAL**	247,646	6,116,893	18,746,910	1,660,363	164,253	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*26,936,065*	*22,449,782*
30	**OTHER COSTS**																								
31	**Cost of Legacy Meters**																								
32	Cost of underdepreciated meters	0	2,780,048	14,161,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16,941,315	14,107,445
33	*TOTAL - Cost Underdeprecieted Meters*	0	2,780,048	14,161,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*16,941,315*	*14,107,445*
34	**TOTAL OTHER COSTS**	0	2,780,048	14,161,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*16,941,315*	*14,107,445*
35	**O&M COSTS**																								
36	**Communications Network**																								
37	Communications Cost	910	205,368	246,613	427,204	383,467	79,491	81,121	82,784	84,481	86,213	87,980	89,784	91,624	93,503	95,420	97,376	99,372	101,409	103,488	105,609	107,774	109,984	2,860,976	1,650,108
38	Communication Contingency	0	0	56,656	136,102	114,828																		307,586	234,867
39	*TOTAL - Communications*	*910*	*205,368*	*303,269*	*563,306*	*498,295*	*79,491*	*81,121*	*82,784*	*84,481*	*86,213*	*87,980*	*89,784*	*91,624*	*93,503*	*95,420*	*97,376*	*99,372*	*101,409*	*103,488*	*105,609*	*107,774*	*109,984*	*3,168,561*	*1,884,974*
40	**IT Systems and Integration**																								
41	IT Hardware Maintenance	6,650	7,153	7,153	7,153	7,153	7,917	8,079	8,245	8,414	8,586	8,762	8,942	9,125	9,312	9,503	9,698	9,897	10,100	10,307	10,518	10,733	10,954	194,351	94,667
42	Software Maintenance	419	838	1,257	1,257	1,257	1,392	1,420	1,449	1,479	1,509	1,540	1,572	1,604	1,637	1,671	1,705	1,740	1,775	1,812	1,849	1,887	1,925	32,995	15,570
43	IT labor	15,753	67,721	64,492	37,921	46,384	44,476	46,006	47,588	49,225	50,918	52,670	54,482	56,356	58,295	60,300	62,374	64,520	66,740	69,035	71,410	73,867	76,408	1,236,941	595,696
44	Outside Vendor Contract	12,307	76,979	64,728	41,563	49,394	48,118	49,104	50,111	51,138	52,187	53,257	54,348	55,462	56,599	57,760	58,944	60,152	61,385	62,644	63,928	65,238	66,576	1,211,925	598,796
45	IT Contingency (Other)	0	0	195,861	97,749	45,871	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	339,481	270,006
46	Common Corporate Business System development-	0	122,298	497,943	684,174	854,810	840,973	750,937	656,855	558,600	456,041	349,043	237,465	121,167	0	0	0	0	0	0	0	0	0	6,130,306	3,988,464
47	*TOTAL - IT Systems and Integration*	*35,128*	*274,990*	*831,434*	*869,818*	*1,004,870*	*942,875*	*855,546*	*764,248*	*668,857*	*569,242*	*465,272*	*356,809*	*243,714*	*125,843*	*129,233*	*132,721*	*136,309*	*140,000*	*143,797*	*147,705*	*151,725*	*155,863*	*9,145,999*	*5,563,200*
48	**Program and Project Management Costs**																								
49	Change Management, PMO, Supply Chain, Security	52,894	75,717	578,908	458,916	53,117	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1,219,552	985,749
50	*TOTAL - Program Management*	*52,894*	*75,717*	*578,908*	*458,916*	*53,117*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1,219,552*	*985,749*
51	**AMI Operations**																								
52	AMI Operations (Internal Personnel)	0	6,999	35,777	59,951	97,213	115,124	119,085	123,181	127,418	131,802	136,336	141,026	145,877	150,895	156,086	161,455	167,009	172,754	178,697	184,844	191,203	197,780	2,800,513	1,201,767
53	AMI Operations (External Personnel)	0	1,566	13,376	3,462	16,908	20,023	20,712	21,425	22,162	22,924	23,713	24,528	25,372	26,245	27,148	28,081	29,047	30,047	31,080	32,149	33,255	34,399	487,623	209,841
54	Customer Claims	0	0	0	43,500	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	43,500	33,588
55	*TOTAL - AMI Operations*	0	8,565	49,153	106,913	114,121	135,148	139,797	144,606	149,580	154,726	160,048	165,554	171,249	177,140	183,233	189,537	196,057	202,801	209,777	216,994	224,458	232,180	*3,331,635*	*1,445,195*
56	**TOTAL O&M**	88,932	564,640	1,762,764	1,998,953	1,670,403	1,157,514	1,076,463	991,638	902,918	810,181	713,300	612,147	506,588	396,486	407,886	419,633	431,737	444,210	457,063	470,308	483,958	498,026	16,865,748	9,879,118
57																									
58	**GRAND TOTAL CAPITAL & O&M**	336,578	9,461,581	34,670,941	3,659,315	1,834,656	1,157,514	1,076,463	991,638	902,918	810,181	713,300	612,147	506,588	396,486	407,886	419,633	431,737	444,210	457,063	470,308	483,958	498,026	60,743,127	46,436,345

Southwestern Public Service Company

AMI Cost-Benefit Analysis

#	BENEFITS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	TOTAL	NPV
2	*Total Meters Replaced*	0	20,000	102,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	122,000	
3	**O&M ITEMS**																								
4	**Avoided O&M Meter Reading Costs**																								
5	Meter Reading Labor Savings - O&M	0	0	311,306	1,288,058	1,332,367	1,378,200	1,425,610	1,474,651	1,525,379	1,577,852	1,632,131	1,688,276	1,746,353	1,806,427	1,868,568	1,932,847	1,999,337	2,068,114	2,139,257	2,212,848	2,288,970	1,979,561	33,676,111	14,685,667
6	Meter Reading Fleet Savings - O&M	0	0	54,375	221,957	226,507	231,151	235,889	240,725	245,660	250,696	255,835	261,080	266,432	271,894	277,468	283,156	288,960	294,884	300,929	307,098	313,394	267,389	5,095,480	2,281,589
7	***TOTAL - Reduction in Meter Reading Costs***	*0*	*0*	*365,680*	*1,510,015*	*1,558,874*	*1,609,351*	*1,661,500*	*1,715,376*	*1,771,039*	*1,828,548*	*1,887,966*	*1,949,356*	*2,012,785*	*2,078,321*	*2,146,036*	*2,216,003*	*2,288,297*	*2,362,998*	*2,440,186*	*2,519,946*	*2,602,363*	*2,246,950*	*38,771,592*	*16,967,256*
8	**Reduction in Field and Meter Services**																								
9	Costs savings from remote disconnect capability	0	0	183,472	759,133	785,247	812,259	840,201	869,104	899,001	929,927	961,916	995,006	1,029,234	1,064,640	1,101,264	1,139,147	1,178,334	1,218,869	1,260,798	1,304,169	1,349,032	1,166,679	19,847,432	8,655,179
10	Reduction in costs associated with special meter reads	0	0	47,590	196,907	203,681	210,687	217,935	225,432	233,187	241,208	249,506	258,089	266,967	276,151	285,650	295,477	305,641	316,155	327,031	338,281	349,918	302,618	5,148,108	2,245,016
11	Reduction in trips due to Customer equipment damage	0	0	7,857	32,510	33,628	34,785	35,982	37,219	38,500	39,824	41,194	42,611	44,077	45,593	47,162	48,784	50,462	52,198	53,994	55,851	57,772	49,963	849,968	370,659
12	Reduction in "OK on Arrival" Outage Field Trips	0	0	22,243	92,034	95,200	98,474	101,862	105,366	108,991	112,740	116,618	120,630	124,779	129,072	133,512	138,105	142,856	147,770	152,853	158,111	163,550	141,443	2,406,207	1,049,312
13	Reduction in nuisance stopped meter orders	0	0	33,014	136,597	141,296	146,156	151,184	156,385	161,764	167,329	173,085	179,039	185,198	191,569	198,159	204,976	212,027	219,321	226,865	234,670	242,742	209,930	3,571,307	1,557,395
14	Reduction in labor associated with estimated bills	0	0	51,814	214,385	221,760	229,389	237,280	245,442	253,885	262,619	271,653	280,998	290,664	300,663	311,006	321,705	332,771	344,219	356,060	368,308	380,978	329,480	5,605,079	2,444,294
15	Savings from reduction in call volume	0	0	7,231	29,918	30,947	32,011	33,113	34,252	35,430	36,649	37,909	39,214	40,562	41,958	43,401	44,894	46,439	48,036	49,688	51,398	53,166	45,979	782,194	341,103
16	Reduction in Field Trips for Voltage Investigations	0	0	5,741	23,756	24,573	25,418	26,293	27,197	28,133	29,101	30,102	31,137	32,208	33,316	34,462	35,648	36,874	38,143	39,455	40,812	42,216	36,510	621,097	270,851
17	***TOTAL - Reduction in Field & Meter Services***	*0*	*0*	*358,961*	*1,485,239*	*1,536,331*	*1,589,181*	*1,643,849*	*1,700,397*	*1,758,891*	*1,819,397*	*1,881,984*	*1,946,724*	*2,013,692*	*2,082,962*	*2,154,616*	*2,228,735*	*2,305,404*	*2,384,710*	*2,466,744*	*2,551,600*	*2,639,375*	*2,282,600*	*38,831,391*	*16,933,811*
18	**Improved Distribution System Spend Efficiency**																								
19	Efficiency gains reliability, asset health and capacity-O&M	0	0	116	480	497	514	532	550	569	588	609	630	651	674	697	721	746	771	798	825	854	883	12,702	5,511
20	***TOTAL - Improved Distribution System Spend Efficiency***	*0*	*0*	*116*	*480*	*497*	*514*	*532*	*550*	*569*	*588*	*609*	*630*	*651*	*674*	*697*	*721*	*746*	*771*	*798*	*825*	*854*	*883*	*12,702*	*5,511*
21	**Outage Management Efficiency**																								
22	Outage Management Efficiency (Storm spend O&M)	0	0	6,229	25,774	26,661	27,578	28,526	29,508	30,523	31,573	32,659	33,782	34,944	36,146	37,390	38,676	40,006	41,383	42,806	44,279	45,802	39,611	673,855	293,858
23	***TOTAL - Outage Management Efficiency***	*0*	*0*	*6,229*	*25,774*	*26,661*	*27,578*	*28,526*	*29,508*	*30,523*	*31,573*	*32,659*	*33,782*	*34,944*	*36,146*	*37,390*	*38,676*	*40,006*	*41,383*	*42,806*	*44,279*	*45,802*	*39,611*	*673,855*	*293,858*
24	**TOTAL O&M BENEFITS**	0	0	730,987	3,021,508	3,122,363	3,226,624	3,334,406	3,445,831	3,561,022	3,680,106	3,803,217	3,930,492	4,062,072	4,198,103	4,338,739	4,484,135	4,634,453	4,789,862	4,950,534	5,116,650	5,288,394	4,570,044	78,289,540	34,200,436
25	**OTHER BENEFITS**																								
26	**Cost reductions**																								
27	Reduced Consumption on Inactive Meters	0	0	5,805	23,696	24,182	24,677	25,183	25,699	26,226	26,764	27,313	27,873	28,444	29,027	29,622	30,229	30,849	31,481	32,127	32,785	33,458	28,546	543,987	243,579
28	Reduced Uncollectible / Bad Debt Expense	0	0	32,539	134,635	139,267	144,058	149,013	154,139	159,442	164,926	170,600	176,468	182,539	188,818	195,314	202,032	208,982	216,171	223,608	231,300	239,256	206,915	3,520,024	1,535,032
29	Reduced outage duration benefit	0	0	15,621	63,766	65,073	66,407	67,769	69,158	70,576	72,023	73,499	75,006	76,543	78,112	79,714	81,348	83,016	84,717	86,454	88,226	90,035	76,818	1,463,882	655,478
30	Theft / Tamper Detection & Reduction	0	0	156,077	637,105	650,166	663,494	677,096	690,977	705,142	719,597	734,349	749,403	764,766	780,443	796,442	812,769	829,431	846,435	863,786	881,494	899,565	767,513	14,626,050	6,549,065
31	***TOTAL - Cost Reductions***	0	0	210,043	859,203	878,688	898,637	919,061	939,973	961,385	983,310	1,005,760	1,028,750	1,052,292	1,076,401	1,101,092	1,126,379	1,152,278	1,178,805	1,205,975	1,233,806	1,262,314	1,079,793	*20,153,943*	*8,983,155*
32	**Load Flexibility Benefits**																								
33	Critical Peak Pricing -CPP-DSM Peak	0	0	0	0	0	0	0	0	1,683,145	1,754,768	1,832,684	1,888,611	1,926,383	1,964,911	2,004,209	2,044,293	2,085,179	2,126,883	2,169,420	2,212,809	2,257,065	1,924,796	27,875,157	10,388,171
34	Time Of Usage-TOU-Customer energy price shift	0	0	0	0	0	169,527	182,283	176,890	192,014	187,221	180,227	178,417	171,218	155,494	164,212	158,569	144,109	141,435	152,244	134,333	149,829	141,862	2,779,885	1,214,224
35	***TOTAL - Load Flexibility Benefits***	0	0	0	0	0	169,527	182,283	176,890	1,875,160	1,941,989	2,012,912	2,067,028	2,097,602	2,120,405	2,168,421	2,202,863	2,229,288	2,268,317	2,321,665	2,347,142	2,406,894	2,066,657	*30,655,042*	*11,602,394*
36	**TOTAL OTHER BENEFITS**	0	0	210,043	859,203	878,688	1,068,164	1,101,345	1,116,863	2,836,545	2,925,298	3,018,672	3,095,778	3,149,894	3,196,806	3,269,513	3,329,242	3,381,566	3,447,122	3,527,640	3,580,948	3,669,207	3,146,450	50,808,985	20,585,549
37	**CAPITAL ITEMS**																								
38	**Capital gains and other avoided purchases**																								
39	Efficiency gains reliability, asset health and capacity-CAP	0	0	45,929	187,483	191,327	195,249	199,251	203,336	207,504	211,758	216,099	220,529	225,050	229,664	234,372	239,176	244,080	249,083	254,189	259,400	264,718	225,859	4,304,057	1,927,215
40	Outage Management Efficiency (Storm spend CAP)	0	0	25,176	104,168	107,751	111,458	115,292	119,258	123,360	127,604	131,993	136,534	141,231	146,089	151,115	156,313	161,690	167,252	173,006	178,957	185,113	160,091	2,723,448	1,187,657
41	Avoided Failed Meter Purchases	0	129,454	821,255	844,270	859,728	881,837	904,554	927,896	951,882	976,530	1,001,860	1,027,893	1,054,648	1,082,146	1,110,411	1,139,465	1,169,330	1,200,031	1,231,594	1,264,042	1,297,404	941,429	20,817,659	9,551,405
42	***TOTAL - Efficiency gains and other avoided CAP purchases***	0	129,454	892,360	1,135,921	1,158,805	1,188,543	1,219,097	1,250,490	1,282,747	1,315,892	1,349,953	1,384,956	1,420,928	1,457,899	1,495,897	1,534,954	1,575,099	1,616,367	1,658,789	1,702,400	1,747,235	1,327,379	*27,845,164*	*12,666,277*
43	**Avoided Meter Reading CAP Investment**																								
44	Walk Meter Reading Cost - CAP	0	0	804,255	0	0	0	0	0	0	0	0	0	1,127,922	0	0	0	0	0	0	0	0	0	1,932,177	1,149,174
45	***TOTAL - Avoided Meter Reading CAP Investment***	*0*	*0*	*804,255*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1,127,922*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*1,932,177*	*1,149,174*
46	**TOTAL CAPITAL BENEFITS**	0	129,454	1,696,615	1,135,921	1,158,805	1,188,543	1,219,097	1,250,490	1,282,747	1,315,892	1,349,953	1,384,956	2,548,850	1,457,899	1,495,897	1,534,954	1,575,099	1,616,367	1,658,789	1,702,400	1,747,235	1,327,379	29,777,341	13,815,451
47																									
48	**GRAND TOTAL BENEFITS**	0	129,454	2,637,645	5,016,631	5,159,856	5,483,330	5,654,848	5,813,184	7,680,313	7,921,297	8,171,842	8,411,225	9,760,815	8,852,809	9,104,150	9,348,330	9,591,119	9,853,350	10,136,963	10,399,997	10,704,836	9,043,873	158,875,866	68,601,436

Southwestern Public Service Company

AMI Cost-Benefit Analysis

Line	Excludes Critical Peak Pricing (CPP)		Includes Critical Peak Pricing (CPP)	
2	***SPS-NM -AMI-NPV***	**Total ($MM)**	***SPS-NM -AMI-NPV***	**Total ($MM)**
3	**Benefits**	**46**	**Benefits**	**56**
4	O&M Benefits	34	O&M Benefits	34
5	Other Benefits	10	Other Benefits	21
6	CAP Benefits	1	CAP Benefits	1
7	**Costs**	**(41)**	**Costs**	**(41)**
8	O&M Expense	(10)	O&M Expense	(10)
9	Change in Revenue Requirements	(31)	Change in Revenue Requirements	(31)
10	**Benefit/Cost Ratio**	**1.10**	**Benefit/Cost Ratio**	**1.36**
11				
12				
13	RATIO SENSITIVITY		RATIO SENSITIVITY	
14	**100% Contingencies**	**1.10**	**100% Contingencies**	**1.36**
15	NO Contingencies	**1.23**	NO Contingencies	**1.51**

Southwestern Public Service Company

FLISR Cost-Benefit Analysis

1	COSTS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	TOTAL	NPV
2	**CAPITAL ITEMS - SUMMARY**																								
3	**FLISR Assets**																								
4	Asset Cost	0	0	1,467,500	1,702,300	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**3,169,800**	**2,523,171**
5	Asset Installation	0	0	389,500	451,820	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**841,320**	**669,693**
6	Substation Relay Upgrades	0	0	136,666	193,545	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**330,211**	**262,013**
7	Xcel Personnel - Engineering	0	0	83,750	97,150	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
8	Asset Contingency	0	0	0	0	500,000	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**500,000**	**361,895**
9	***TOTAL - Assets Cost***	***0***	***0***	***2,077,416***	***2,444,815***	***500,000***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***5,022,231***	**3,960,769**
10	**TOTAL CAPITAL**	**0**	**0**	**2,077,416**	**2,444,815**	**500,000**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**5,022,231**	**3,960,769**
11																									
12	**O&M ITEMS - SUMMARY**																								
13	**Deployment**																								
14	O&M in support of capital deployment	0	0	63,045	188,939	180,905	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**432,889**	**328,752**
15	***TOTAL - Asset Operations***	***0***	***0***	***63,045***	***188,939***	***180,905***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***432,889***	**328,752**
16	**Ongoing Support**																								
17	On-going Asset/Device support	0	0	5,625	12,150	12,150	13,447	13,723	14,004	14,292	14,585	14,884	15,189	15,500	15,818	16,142	16,473	16,811	17,155	17,507	17,866	18,232	18,606	**300,158**	**134,165**
18	Component Replacements	0	0	1,313	2,835	2,835	3,138	3,202	3,268	3,335	3,403	3,473	3,544	3,617	3,691	3,766	3,844	3,922	4,003	4,085	4,169	4,254	4,341	**70,037**	**31,305**
19	On-going Communications Network costs	0	0	4,375	9,450	9,450	10,459	10,674	10,892	11,116	11,344	11,576	11,813	12,056	12,303	12,555	12,812	13,075	13,343	13,617	13,896	14,181	14,471	**233,456**	**104,351**
20	Training	0	0	10,000	10,000	10,000	11,842	12,250	12,671	13,107	13,558	14,024	14,507	15,006	15,522	16,056	16,608	17,180	17,771	18,382	19,014	19,668	20,345	**297,513**	**131,155**
21	Asset Contingency	0	0	22,465	132,349	152,903	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**307,718**	**231,365**
22	***TOTAL - Assets Cost***	***0***	***0***	***43,778***	***166,784***	***187,338***	***38,887***	***39,849***	***40,836***	***41,849***	***42,889***	***43,957***	***45,053***	***46,178***	***47,333***	***48,520***	***49,737***	***50,988***	***52,272***	***53,590***	***54,945***	***56,335***	***57,763***	***1,208,882***	**632,341**
23	**TOTAL O&M**	**0**	**0**	**106,823**	**355,724**	**368,243**	**38,887**	**39,849**	**40,836**	**41,849**	**42,889**	**43,957**	**45,053**	**46,178**	**47,333**	**48,520**	**49,737**	**50,988**	**52,272**	**53,590**	**54,945**	**56,335**	**57,763**	**1,641,770**	**961,093**
24																									
25	**GRAND TOTAL CAPITAL & O&M**	**0**	**0**	**2,184,239**	**2,800,539**	**868,243**	**38,887**	**39,849**	**40,836**	**41,849**	**42,889**	**43,957**	**45,053**	**46,178**	**47,333**	**48,520**	**49,737**	**50,988**	**52,272**	**53,590**	**54,945**	**56,335**	**57,763**	**6,664,001**	**4,921,862**

Southwestern Public Service Company

FLISR Cost-Benefit Analysis

1	**BENEFITS**	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	TOTAL	NPV
2																									
3																									
4	CUSTOMER BENEFITS																								
5	Customer Minutes Out- CMO Customer Savings	0	0	0	0	0	112,334	573,184	935,895	1,193,851	1,218,325	1,243,301	1,268,789	1,294,799	1,321,342	1,348,430	1,376,073	1,404,282	1,433,070	1,462,448	1,492,428	1,523,023	1,554,245	**20,755,819**	**8,112,210**
6																									
7	TOTAL CUSTOMER IMPACTS	0	0	0	0	0	112,334	573,184	935,895	1,193,851	1,218,325	1,243,301	1,268,789	1,294,799	1,321,342	1,348,430	1,376,073	1,404,282	1,433,070	1,462,448	1,492,428	1,523,023	1,554,245	20,755,819	8,112,210
8																									
9	GRAND TOTAL BENEFITS	0	0	0	0	0	112,334	573,184	935,895	1,193,851	1,218,325	1,243,301	1,268,789	1,294,799	1,321,342	1,348,430	1,376,073	1,404,282	1,433,070	1,462,448	1,492,428	1,523,023	1,554,245	20,755,819	8,112,210

Southwestern Public Service Company

FLISR Cost-Benefit Analysis

Line	SPS-NM FLISR- NPV	Total ($MM)
1	***SPS-NM FLISR- NPV***	**Total ($MM)**
2	**Benefits**	**8**
3	O&M Benefits	0
4	Customer Benefits	8
5	**Costs**	**(6)**
6	O&M Expense	(1)
7	Change in Revenue Requirements	(5)
8	**Benefit/Cost Ratio**	**1.44**
9		
10	RATIO SENSITIVITY	
11	**100% Contingencies**	**1.44**
12	NO Contingencies	**1.51**

Southwestern Public Service Company

Summary of Cost-Benefit Analyses Results

Excludes CPP - Includes Contingencies

SPS-NM -AMI-NPV

	Total ($MM)
Benefits	**46**
O&M Benefits	34
Other Benefits	10
CAP Benefits	1
Costs	**(41)**
O&M Expense	(10)
Change in Revenue Requirements	(31)
Benefit/Cost Ratio	**1.10**

SPS-NM-FLISR-NPV

	Total ($MM)
Benefits	**8**
O&M Benefits	0
Customer Benefits	8
Costs	**(6)**
O&M Expense	(1)
Change in Revenue Requirements	(5)
Benefit/Cost Ratio	**1.44**

SPS -AMI,FLISR-NPV

	Total ($MM)
Benefits	**54**
O&M Benefits	34
Other Benefits	10
Customer Benefits	8
CAP Benefits	1
Costs	**(47)**
O&M Expense	(11)
Change in Revenue Requirement	(36)
Benefit/Cost Ratio	**1.15**

Southwestern Public Service Company

Summary of Cost-Benefit Analyses Results

Excludes CPP and Contingencies

SPS-NM -AMI-PV

	Total ($MM)
Benefits	**46**
O&M Benefits	34
Other Benefits	10
CAP Benefits	1
Costs	**(37)**
O&M Expense	(9)
Change in Revenue Requirements	(28)
Benefit/Cost Ratio	**1.23**

SPS -AMI,FLISR- NPV

	Total ($MM)
Benefits	**54**
O&M Benefits	34
Other Benefits	10
Customer Benefits	8
CAP Benefits	1
Costs	**(42)**
O&M Expense	(10)
Change in Revenue Requirement	(32)
Benefit/Cost Ratio	**1.27**

SPS-NM-FLISR -NPV

	Total ($MM)
Benefits	**8**
O&M Benefits	0
Customer Benefits	8
Costs	**(5)**
O&M Expense	(1)
Change in Revenue Requirements	(5)
Benefit/Cost Ratio	**1.51**

Southwestern Public Service Company

Summary of Cost-Benefit Analyses Results

1 Includes CPP and Contingencies

	SPS-NM -AMI-NPV	Total ($MM)
3	**Benefits**	**56**
4	O&M Benefits	34
5	Other Benefits	21
6	CAP Benefits	1
7	**Costs**	**(41)**
8	O&M Expense	(10)
9	Change in Revenue Requirements	(31)
10	**Benefit/Cost Ratio**	**1.36**

SPS-NM-FLISR-NPV	Total ($MM)
Benefits	**8**
O&M Benefits	0
Customer Benefits	8
Costs	**(6)**
O&M Expense	(1)
Change in Revenue Requirements	(5)
Benefit/Cost Ratio	**1.44**

11

14	SPS -AMI,FLISR-NPV	Total ($MM)
15	**Benefits**	**64**
16	O&M Benefits	34
17	Other Benefits	21
18	Customer Benefits	8
19	CAP Benefits	1
20	**Costs**	**(47)**
21	O&M Expense	(11)
22	Change in Revenue Requirement	(36)
23	**Benefit/Cost Ratio**	**1.37**

Southwestern Public Service Company

Summary of Cost-Benefit Analyses Results

Includes CPP - Excludes Contingencies

SPS-NM -AMI- *NPV*

	Total ($MM)
Benefits	**56**
O&M Benefits	34
Other Benefits	21
CAP Benefits	1
Costs	**(37)**
O&M Expense	(9)
Change in Revenue Requirements	(28)
Benefit/Cost Ratio	**1.51**

SPS-NM-FLISR *-NPV*

	Total ($MM)
Benefits	**8**
O&M Benefits	0
Customer Benefits	8
Costs	**(5)**
O&M Expense	(1)
Change in Revenue Requirements	(5)
Benefit/Cost Ratio	**1.51**

SPS -AMI,FLISR- *NPV*

	Total ($MM)
Benefits	**64**
O&M Benefits	34
Other Benefits	21
Customer Benefits	8
CAP Benefits	1
Costs	**(42)**
O&M Expense	(10)
Change in Revenue Requirement	(32)
Benefit/Cost Ratio	**1.51**

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

Privileged and Confidential

PRESENTED TO

Xcel Energy

PRESENTED BY

Ahmad Faruqui
Ryan Hledik

April 21, 2016

THE Brattle GROUP

Background

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

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

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

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

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

Overview of methodology

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

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

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

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

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

Overview of methodology (cont'd)

Current Schedule R

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

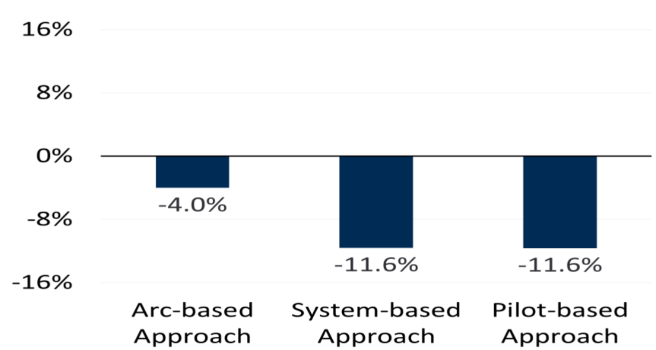
Proposed Schedule RD-TOU

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

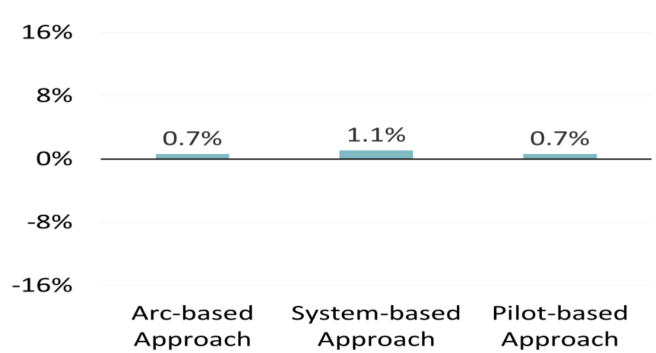
- For each of 200+ customers from Xcel Energy's load research sample, we compare the current Schedule R to the proposed Schedule RD-TOU on a monthly basis for calendar year 2013
- This allows for a comparison of today's two-part rate to a three-part rate that would be enabled by Xcel Energy's grid modernization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

Overview of results

Change in Avg Peak Period Demand (Summer)



Change in Annual Electricity Consumption



Comments

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

Conclusions and recommendations

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

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

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

Methodology Detail

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

770 kWh of monthly electricity consumption

Time-differentiated consumption*

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

IBR tier-differentiated consumption

- 500 kWh first tier
- 270 kWh second tier

3.5 kW of maximum demand

- Measured during peak hours
- Load factor of 30%

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

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

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

Proposed Schedule RD-TOU

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

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

Levelized Prices

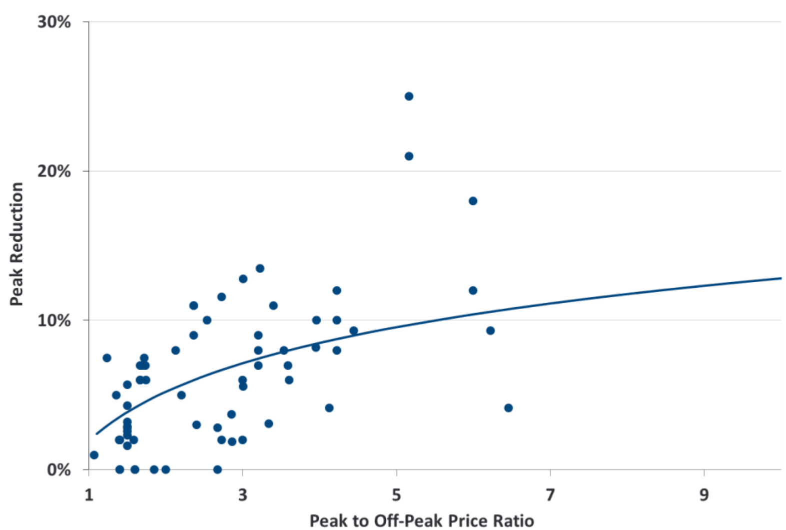
All-in Price	Peak	Off-Peak
Service & facility charge ($/kWh)	0.0130	0.0130
Grid use ($/kWh)	0.0199	0.0199
Non-ECA riders ($/kWh)	0.1518	0
ECA rider ($/kWh)	0.0357	0.0319
Energy ($/kWh)	0.0046	0.0046
Demand ($/kWh)	0.3165	0
Total ($/kWh)	**0.5415**	**0.0694**
All-in peak-to-off peak price ratio	**7.8**	

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

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

The Arc-based Approach

TOU Impacts Observed in Pricing Pilots



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

Comments

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

The Arc-based Approach (cont'd)

Accounting for a Change in Average Price

Current Schedule R

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

Proposed Schedule RD-TOU

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

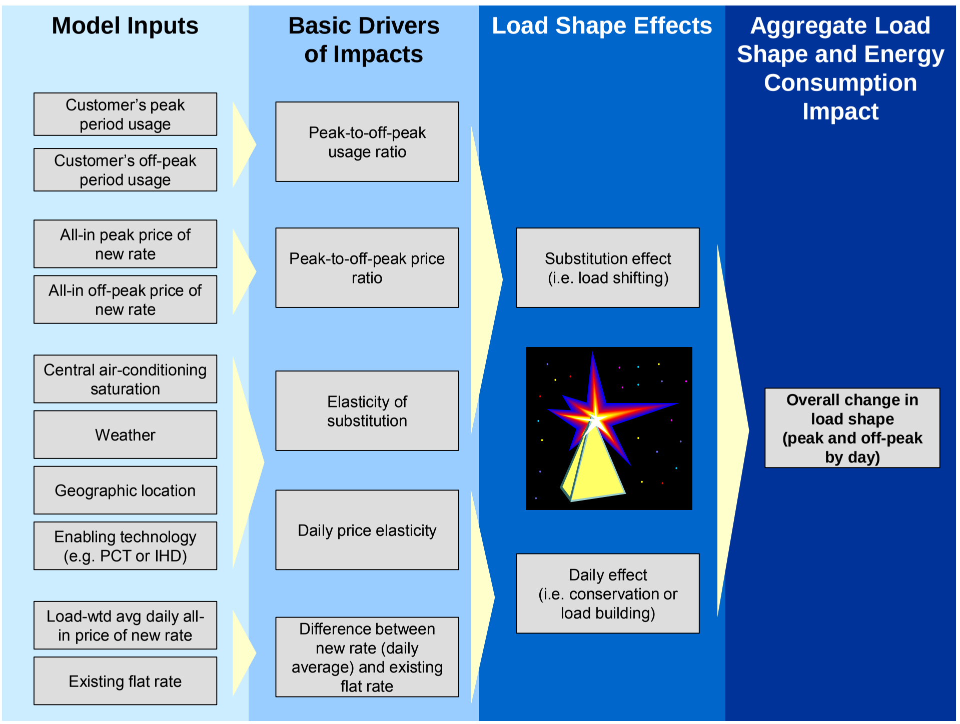
Notes:
Customer is assumed to be in 500-1,000 kWh tier of grid use charge.
Peak period is defined above as 9 am to 9 pm, weekdays, consistent with the definition in the ECA rider.

Comments

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

The System-based Approach

Illustration of System-based Approach



Comments

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

The Pilot-based Approach

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

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

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

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

Price elasticities of demand

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

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

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

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

Derating peak impacts

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

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

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

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

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

Revenue neutrality

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

ECA rider

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

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

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

Production meter charge

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

Demand charge

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

Energy charge

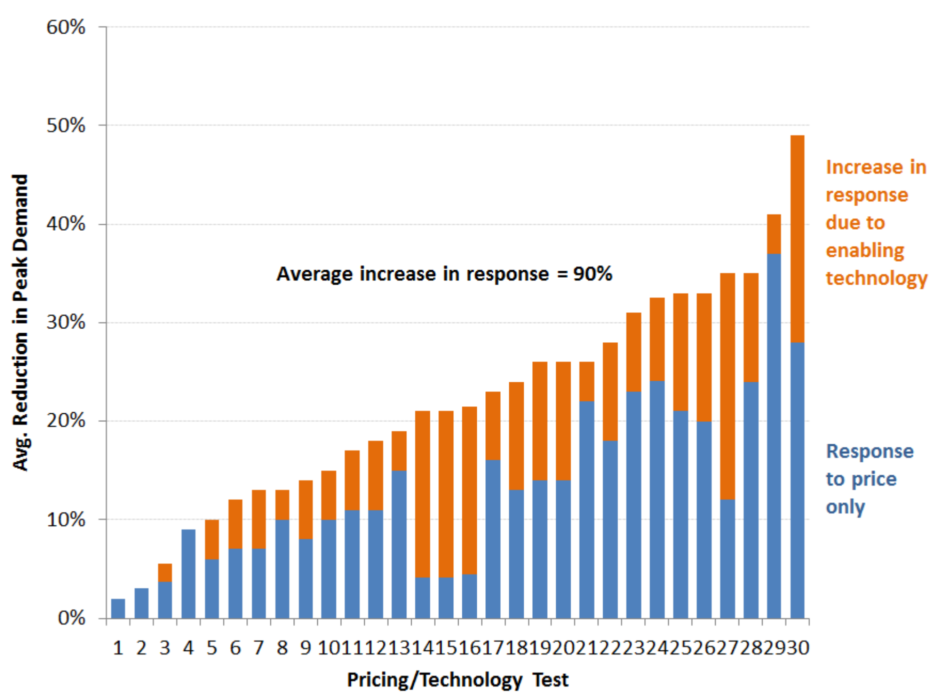
- The energy charge in the RD-TOU rate is adjusted to make up any remaining difference in revenue collected from the current rate and the proposed rate

Load research data

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

The impact of technology

Price Response with and without Technology



Comments

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

Results - Monthly Detail

Monthly change in class average peak period demand

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

Monthly change in class annual energy consumption

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

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

PREPARED FOR

Xcel Energy

PREPARED BY

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Tony Lee

January 2019

THE Brattle GROUP

Notice

The authors would like to thank Jessie Peterson of Xcel Energy for valuable project leadership. They would also like to thank Brattle colleagues Mariko Geronimo Aydin, Colin McIntyre, and John Palfreyman for excellent research and modeling assistance.

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Table of Contents

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

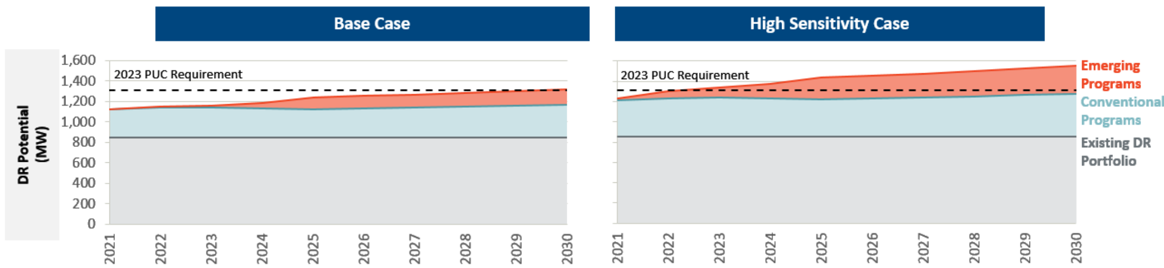
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the 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 <u>not</u> 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.

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[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

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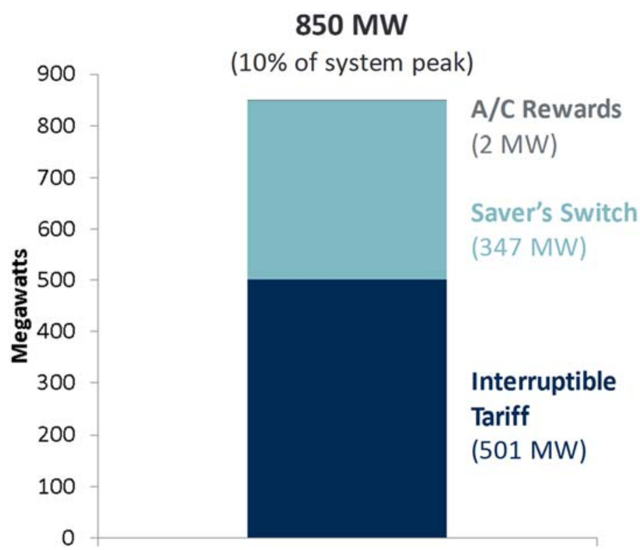
[5] The 2014 study developed a "supply curve" of DR options available to NSP as inputs to its integrated resource plan (IRP), but did not explicitly evaluate the extent to which those options would be less costly than serving electricity demand through the development of new generation resources.

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.

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[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).

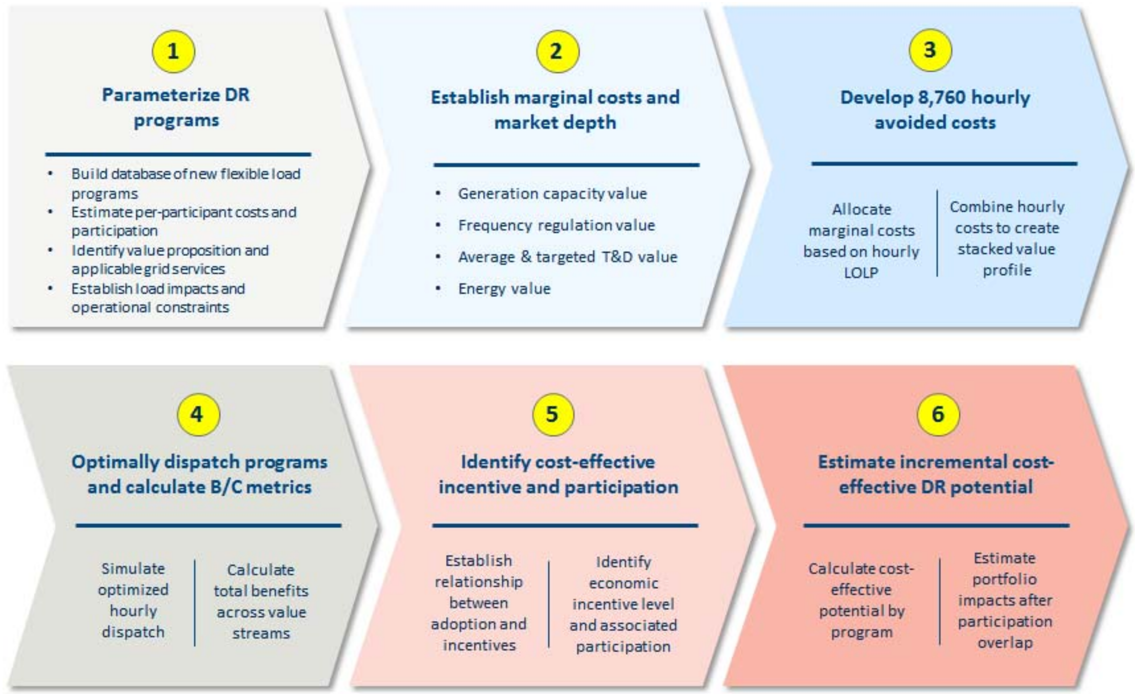
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes 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)

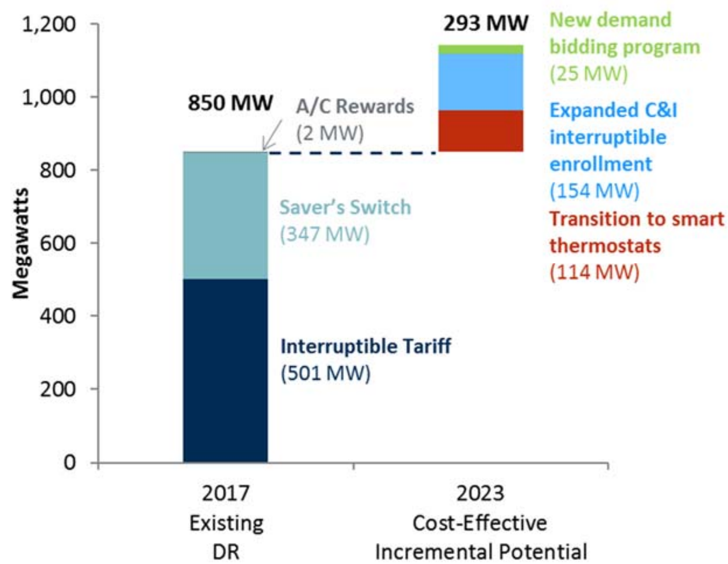
III. Conventional DR Potential in 2023

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.

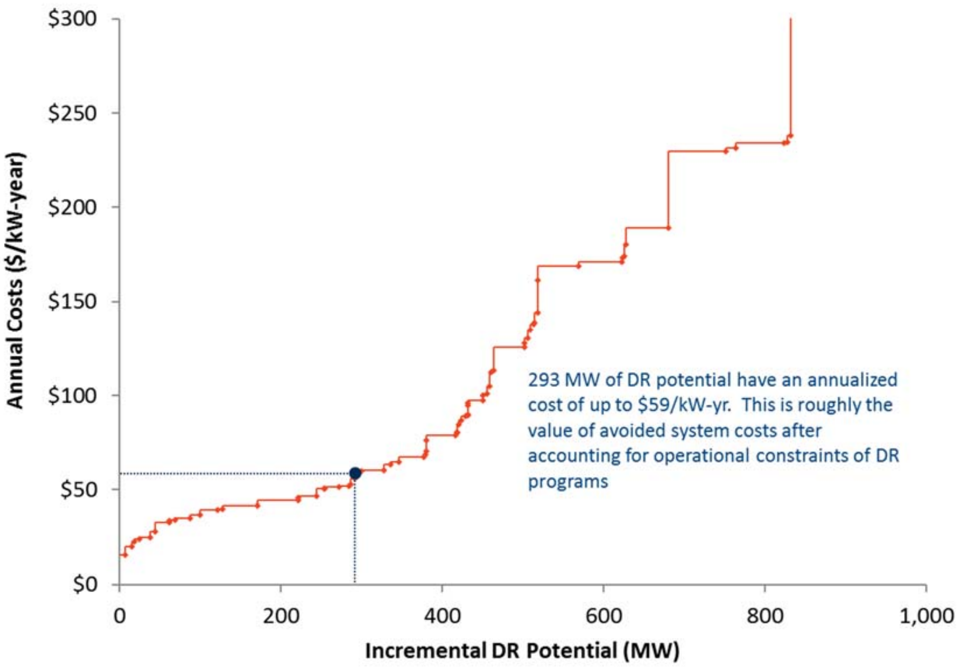
[10] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

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

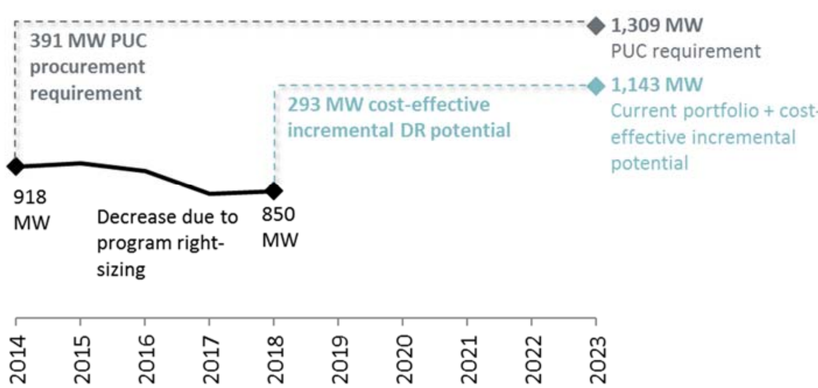
	Requirement (MW)	Notes
Meter level	361.7	Premise-level
Generator level	390.7	Grossed up for 8% line losses
Capacity equivalent	400.0	Grossed up for line losses and reserve requirement

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.

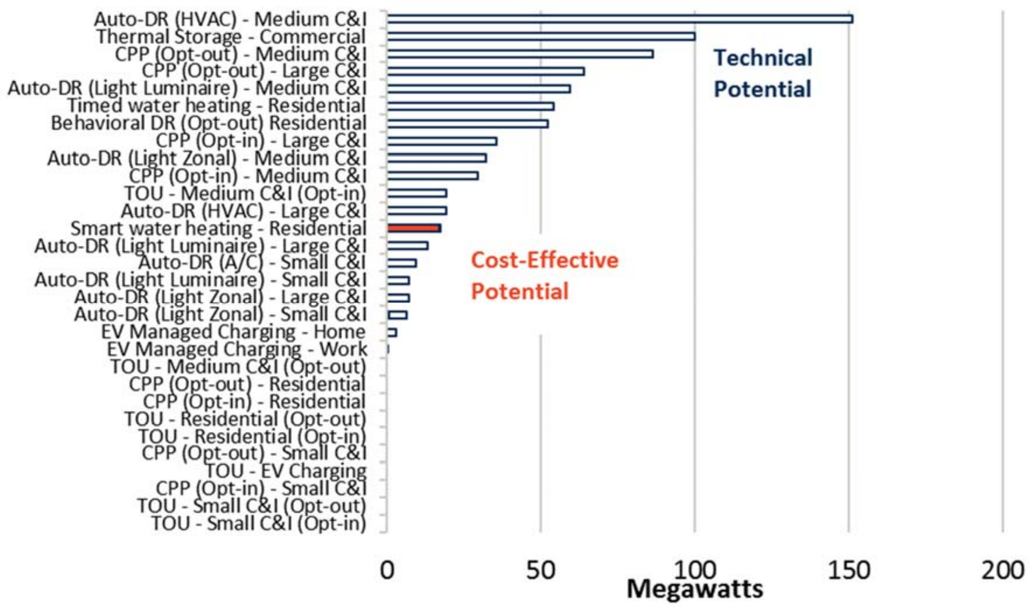
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

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)

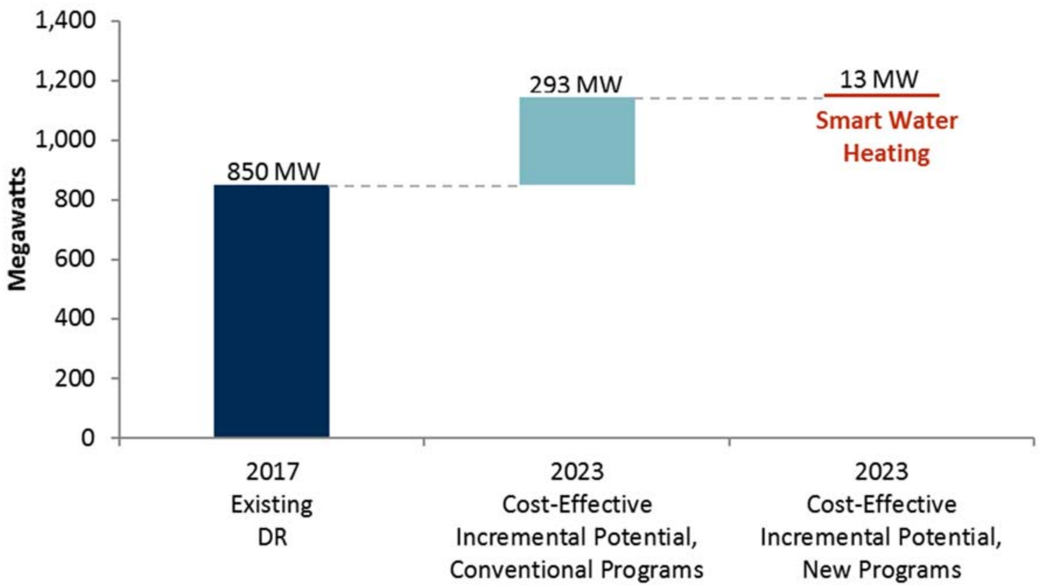


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

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.

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

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

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

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

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

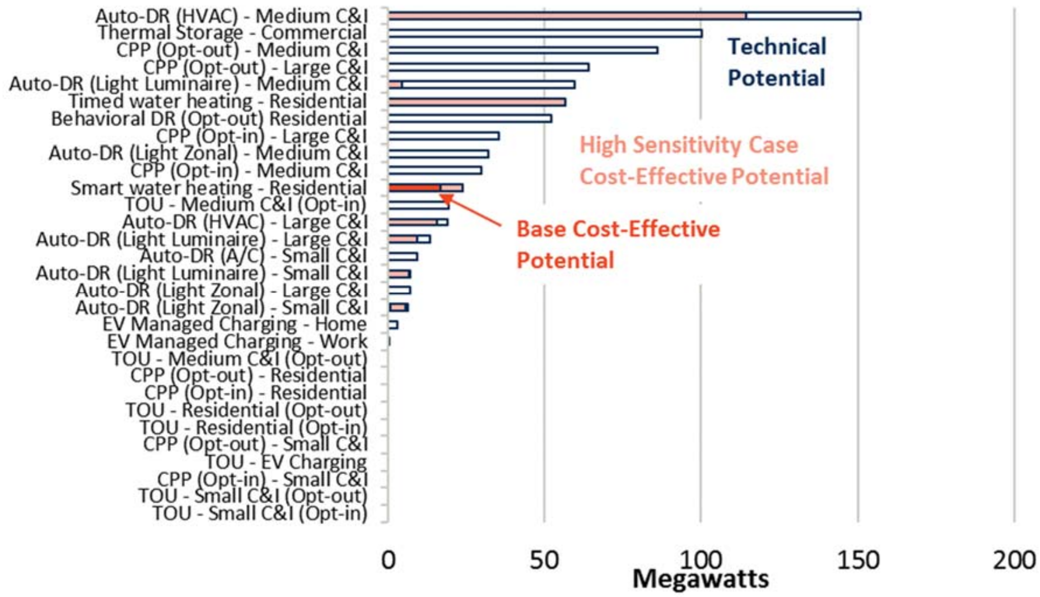
High Sensitivity Case

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

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

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

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



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

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

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

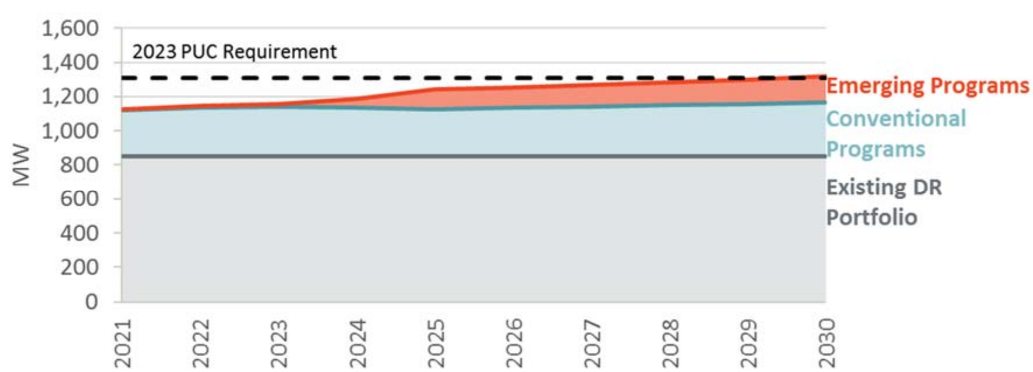
V. Expanded DR Potential in 2030

Base Case

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

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

Figure 11: Cost-Effective DR Potential, Base Case



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

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

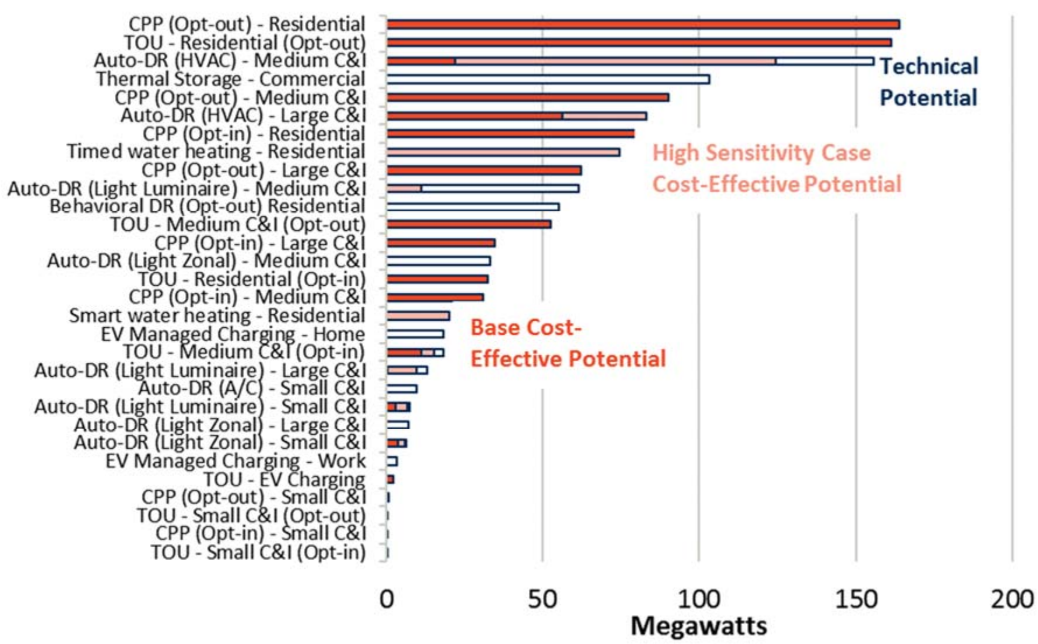
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

Notes: Benefits shown in 2023 dollars.

High Sensitivity Case

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

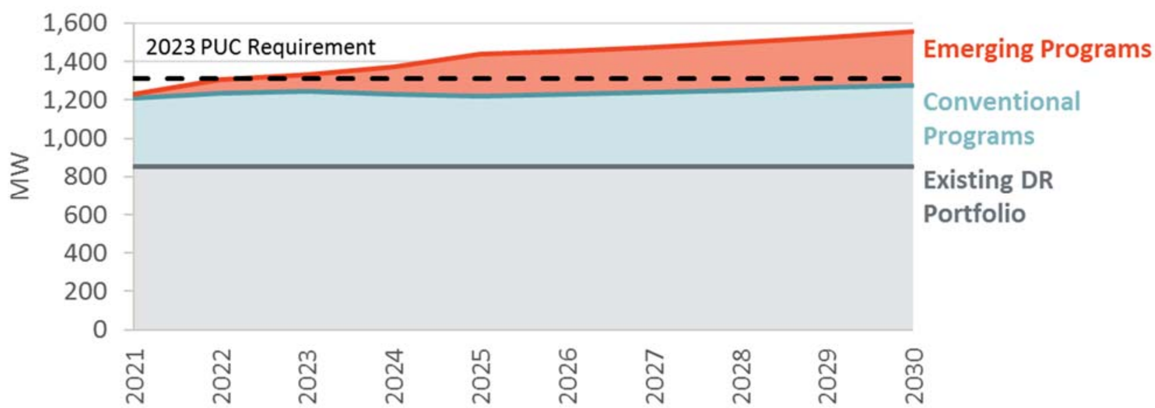
Figure 12: New DR Program Potential in 2030



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

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

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



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

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

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

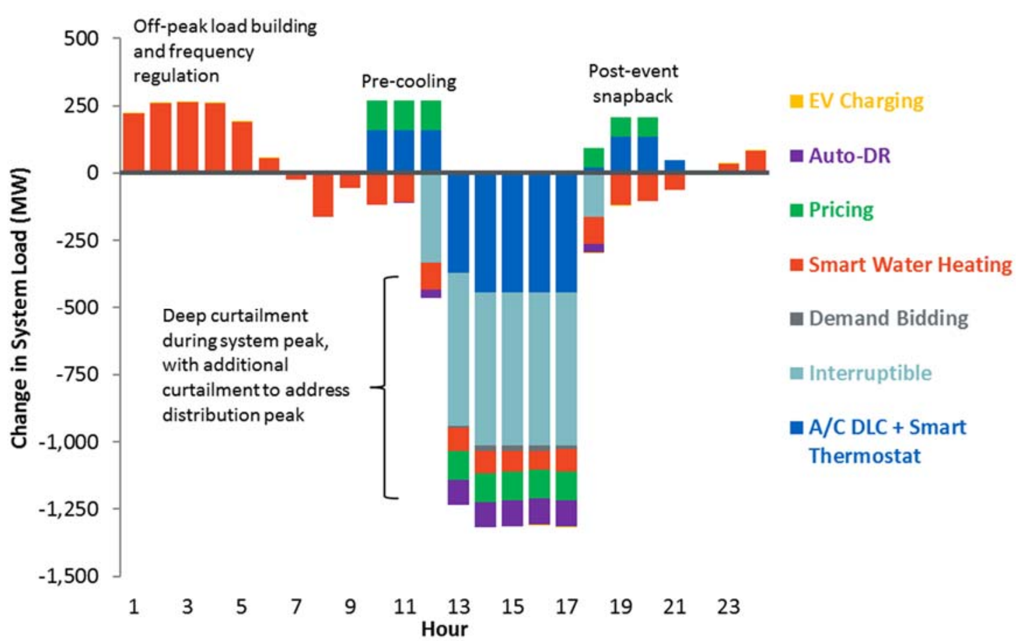
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

Notes: Benefits shown in 2023 dollars.

DR Portfolio Operation

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

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



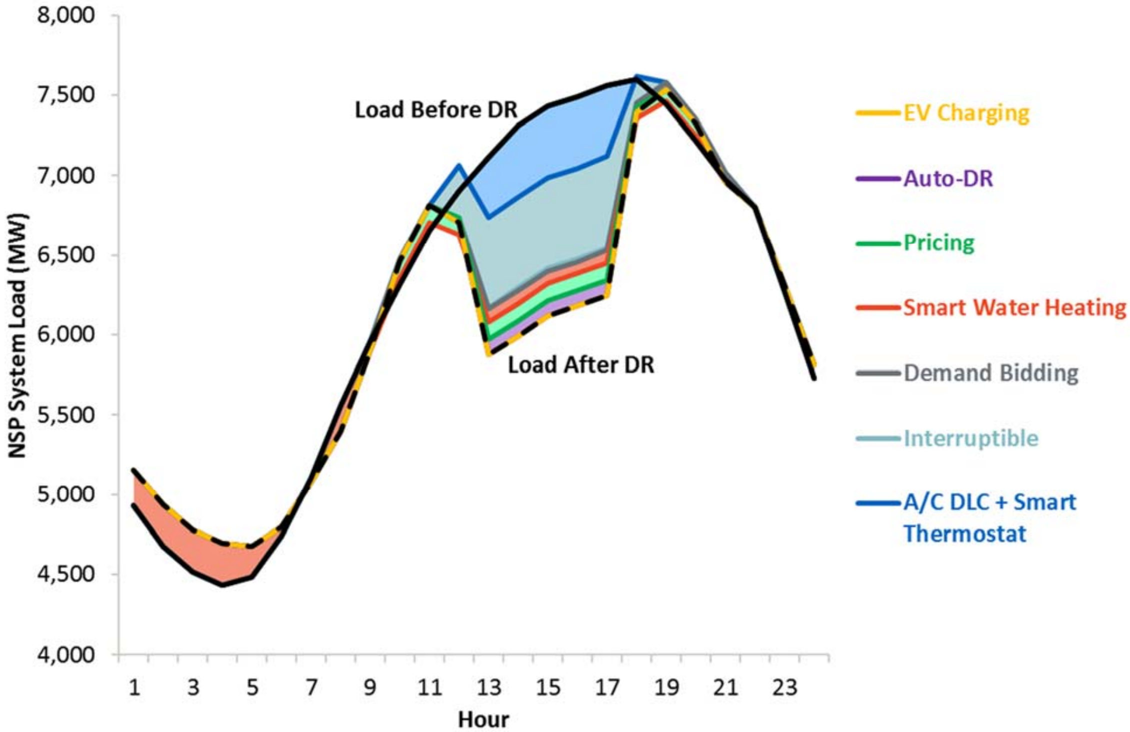
Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

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

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

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

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



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

Sidebar: The Outlook for CTA-2045

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

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

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

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

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

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

VI. Conclusions and Recommendations

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

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

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

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

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

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

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

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Auto-DR

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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).

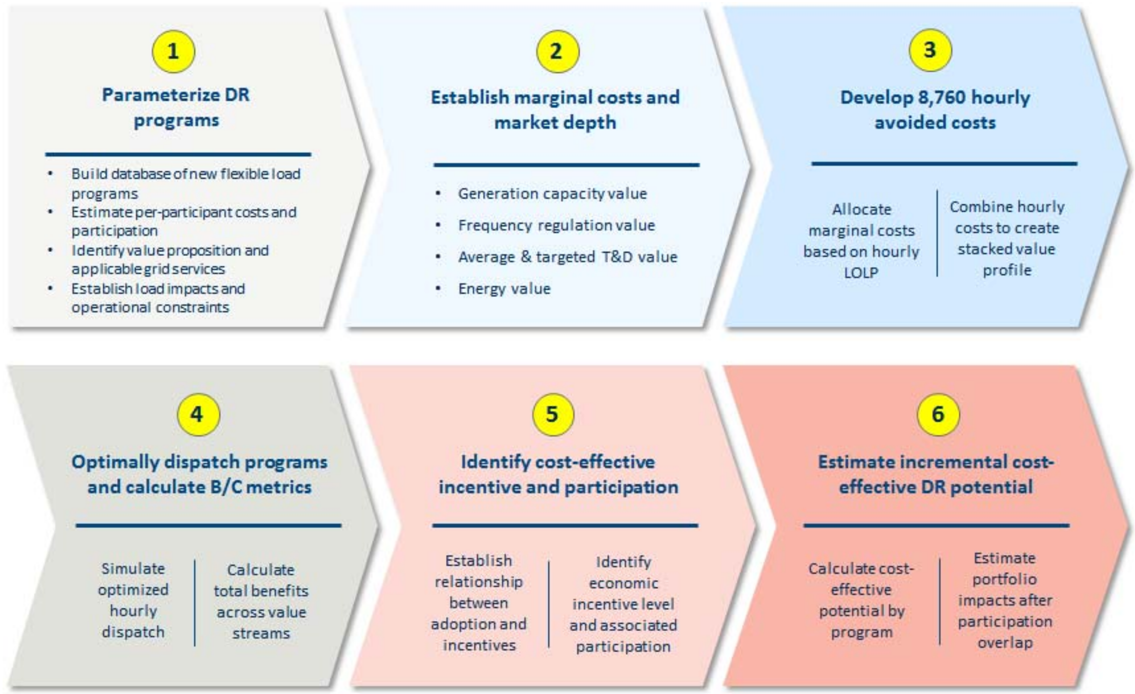
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes 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,

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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.

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"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.

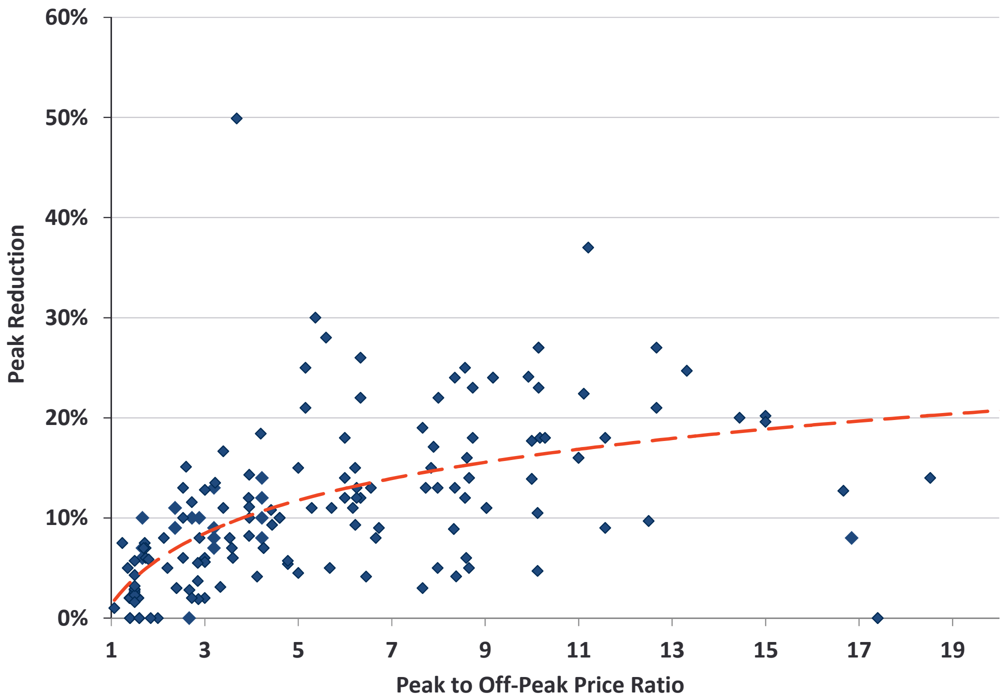
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

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

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

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

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

Avoided system-wide distribution capacity costs

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

Geo-targeted distribution capacity costs

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

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

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

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

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

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

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

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

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

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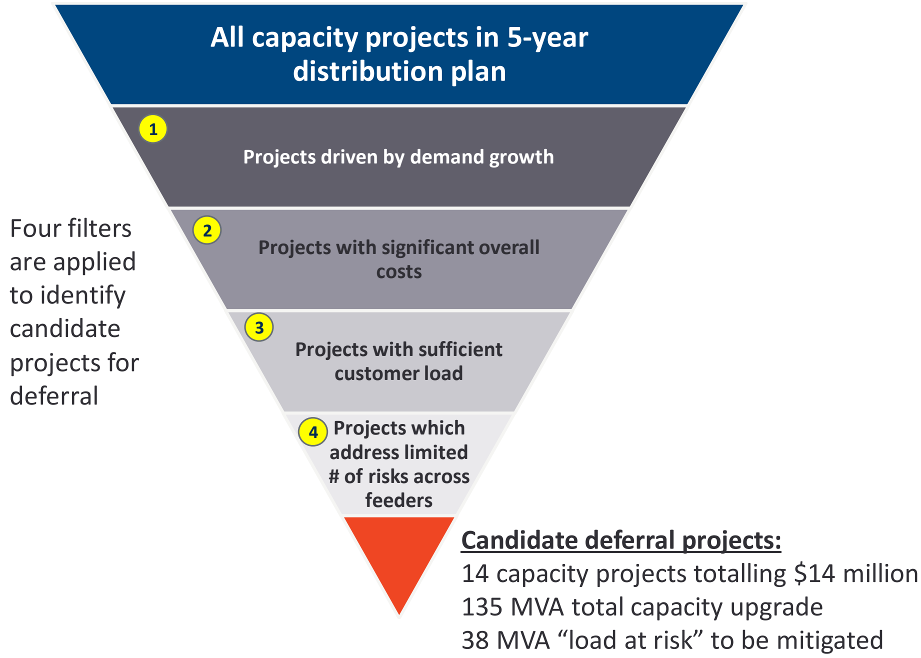
30 For simplicity, we assumed 1 MVA = 1 MW.

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

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



Avoided energy costs

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

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

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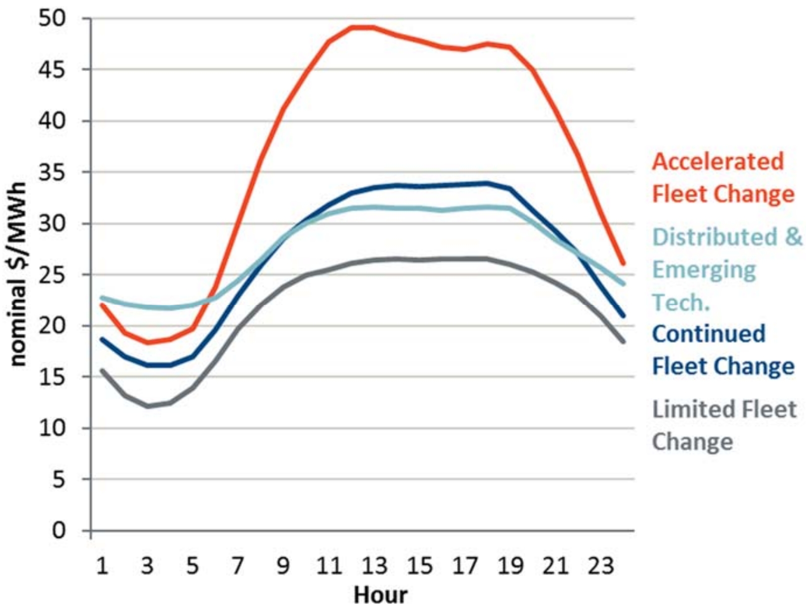
32 Energy savings refer to reduced fuel and O&M costs. In this study, we do not model the impact that DR would have on MISO wholesale energy prices. This is sometimes referred to as the demand response induced price effect (DRIPE). It represents a benefit to consumers and an offsetting cost to producers,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

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

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

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



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

Ancillary services

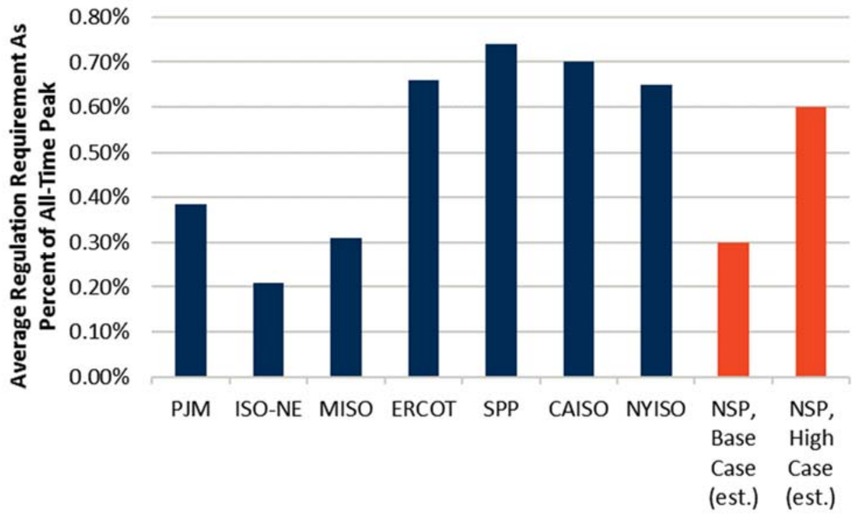
The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service.

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

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

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

Figure 20: Frequency Regulation Requirements Across Wholesale Markets



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

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

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

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

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

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

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

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

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

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

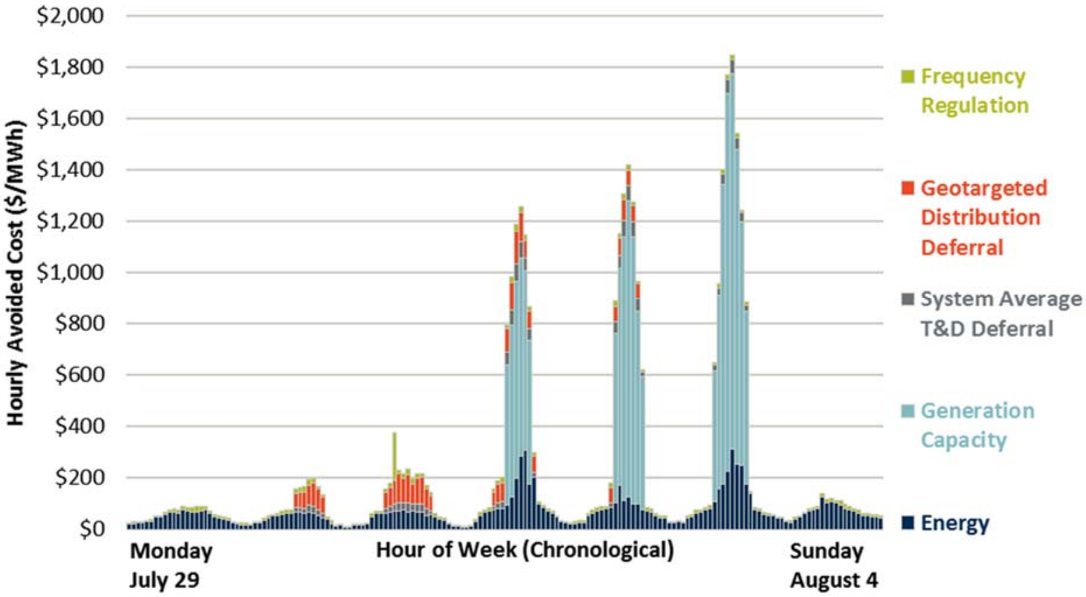
Different allocators are used to allocate generation, transmission, and distribution capacity costs. Generation and transmission capacity costs are allocated based on 2017 hourly MISO system gross load.[35] Distribution capacity costs are allocated based on hourly feeder load data provided by NSP. Both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

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

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

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

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



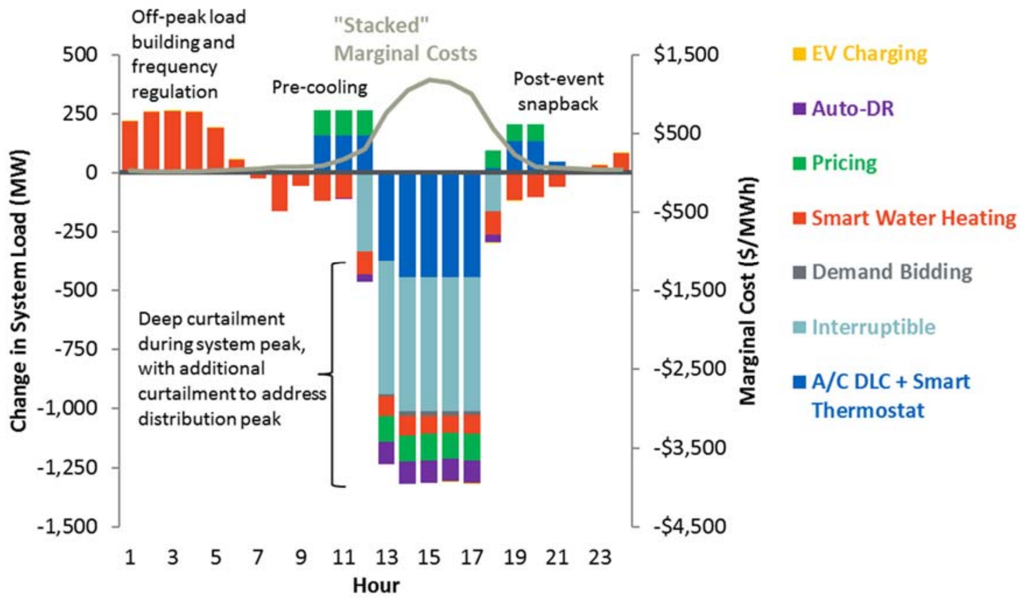
Notes: Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

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

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

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

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



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

Step 5: Identify cost-effective incentive and participation levels

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

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

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

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

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

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

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

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

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

Table 11: Participation Assumptions for Conventional DR Programs

Participation as a percentage of eligible customers

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

Notes:

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

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

Table 12: Participation Assumptions for New DR Programs

Participation as a percentage of eligible customers

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

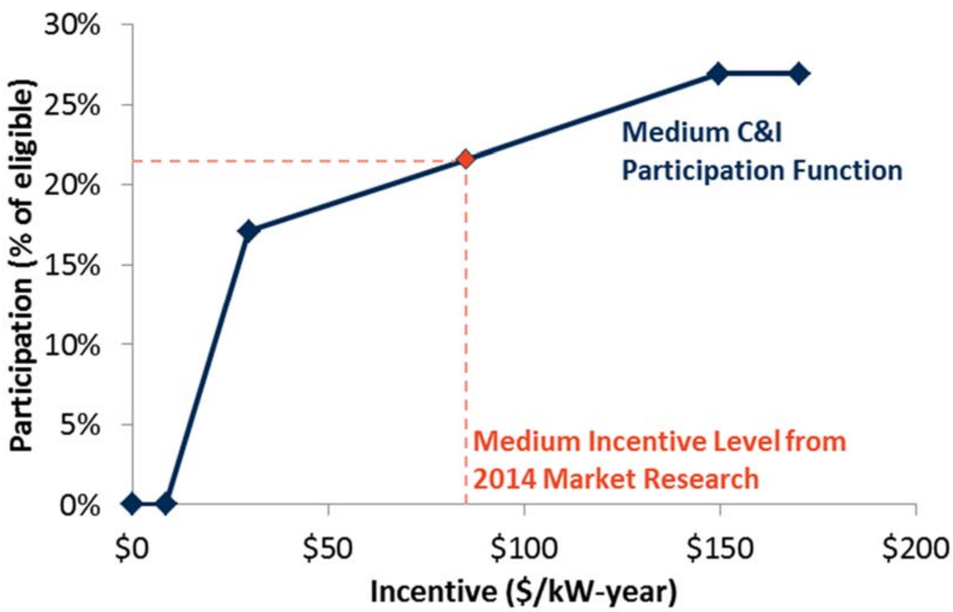
Notes:
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

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

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

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

Figure 23: Medium C&I Interruptible Tariff Adoption Function



Step 6: Estimate cost-effective DR potential

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

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

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

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

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

Appendix B: NSP's Proposed Portfolio

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

Table 13: NSP's Draft Portfolio of DR Programs

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

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

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

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

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

Appendix C: Base Case with Alternative Capacity Costs

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

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

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

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

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

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

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

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

Appendix D: Annual Results Summary

Base Case, All Programs

Technical Potential (MW, at generator-level)

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

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

Base Case, All Programs

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

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

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

Alternative Base Case with Greenfield CT Costs, All Programs

Technical Potential (MW, at generator-level)

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

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

Alternative Base Case with Greenfield CT Costs, All Programs

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

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

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

High Sensitivity Case, All Programs

Technical Potential (MW, at generator-level)

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

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

High Sensitivity Case, All Programs

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

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

Notes:

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

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

Base Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

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

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

Base Case, NSP Proposed Portfolio

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

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

Notes:

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

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

High Sensitivity Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

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

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

High Sensitivity Case, NSP Proposed Portfolio

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

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

Notes:

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

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

BOSTON
NEW YORK
SAN FRANCISCO

WASHINGTON
TORONTO
LONDON

MADRID
ROME
SYDNEY

THE Brattle GROUP

Southwestern Public Service Company

AMR Cost-Benefit Analysis

1	COSTS	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	TOTAL	NPV
2																									0
3	*Total Meters Deployed*	*0*	*20,000*	*102,000*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*122,000*	
4																									
5	**CAPITAL COSTS**																							*TOTAL*	*NSPM-PV*
6	**AMI Meters**																								
7	AMR Meters + Inatall	0	2,948,516	15,734,542	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	18,683,058	15,551,382
8	AMR CAP Cost,Equipment, Vehicles, Other	0	554,744	0	0	0	0	0	0	0	0	0	679,552	0	0	0	0	0	0	0	0	0	0	1,234,296	800,277
9	*TOTAL - AMI Meters*	0	3,503,260	15,734,542	0	0	0	0	0	0	0	0	679,552	0	0	0	0	0	0	0	0	0	0	*19,917,354*	*16,351,658*
10	**TOTAL CAPITAL**	**0**	**3,503,260**	**15,734,542**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**679,552**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***19,917,354***	***16,351,658***
11	**OTHER COSTS**																								
12	**Cost of Current Meters**																								
13	Cost of underdepreciated meters	0	2,780,048	14,161,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	16,941,315	14,107,445
14	*TOTAL - Cost Underdeprecieted Meters*	0	2,780,048	14,161,266	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	*16,941,315*	*14,107,445*
15	**TOTAL OTHER COSTS**	**0**	**2,780,048**	**14,161,266**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	***16,941,315***	***14,107,445***
16	**O&M COSTS**																								
17	**AMI Operations**																								
18	AMR O&M Cost- Equipment, Vehicles, Labor	0	148,020	933,984	966,113	999,348	1,033,725	1,069,285	1,106,069	1,144,117	1,183,475	1,224,187	1,266,299	1,309,859	1,354,918	1,401,528	1,449,740	1,499,611	1,551,198	1,604,559	1,659,756	1,716,852	1,775,911	26,398,555	11,792,313
19	*TOTAL - AMI Operations*	0	148,020	933,984	966,113	999,348	1,033,725	1,069,285	1,106,069	1,144,117	1,183,475	1,224,187	1,266,299	1,309,859	1,354,918	1,401,528	1,449,740	1,499,611	1,551,198	1,604,559	1,659,756	1,716,852	1,775,911	*26,398,555*	*11,792,313*
20	**TOTAL O&M**	**0**	**148,020**	**933,984**	**966,113**	**999,348**	**1,033,725**	**1,069,285**	**1,106,069**	**1,144,117**	**1,183,475**	**1,224,187**	**1,266,299**	**1,309,859**	**1,354,918**	**1,401,528**	**1,449,740**	**1,499,611**	**1,551,198**	**1,604,559**	**1,659,756**	**1,716,852**	**1,775,911**	**26,398,555**	**11,792,313**
21																									
22	**GRAND TOTAL CAPITAL & O&M**	**0**	**6,431,328**	**30,829,793**	**966,113**	**999,348**	**1,033,725**	**1,069,285**	**1,106,069**	**1,144,117**	**1,183,475**	**1,224,187**	**1,945,850**	**1,309,859**	**1,354,918**	**1,401,528**	**1,449,740**	**1,499,611**	**1,551,198**	**1,604,559**	**1,659,756**	**1,716,852**	**1,775,911**	**63,257,223**	**42,251,417**

Southwestern Public Service Company

AMR Cost-Benefit Analysis

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	TOTAL	NPV
1	**BENEFITS**																								
2	*Total Meters Replaced*	*0*	*20,000*	*102,000*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*0*	*122,000*	
3	**O&M ITEMS**																								
4	**Avoided O&M Meter Reading Costs**																								
5	Meter Reading Labor Savings - O&M	0	197,346	1,245,222	1,288,058	1,332,367	1,378,200	1,425,610	1,474,651	1,525,379	1,577,852	1,632,131	1,688,276	1,746,353	1,806,427	1,868,568	1,932,847	1,999,337	2,068,114	2,139,257	2,212,848	2,288,970	2,367,710	**35,195,523**	**15,721,945**
6	Meter Reading Fleet Savings - O&M	0	34,939	217,499	221,957	226,507	231,151	235,889	240,725	245,660	250,696	255,835	261,080	266,432	271,894	277,468	283,156	288,960	294,884	300,929	307,098	313,394	319,818	**5,345,973**	**2,459,299**
7	***TOTAL - Reduction in Meter Reading Costs***	***0***	***232,285***	***1,462,721***	***1,510,015***	***1,558,874***	***1,609,351***	***1,661,500***	***1,715,376***	***1,771,039***	***1,828,548***	***1,887,966***	***1,949,356***	***2,012,785***	***2,078,321***	***2,146,036***	***2,216,003***	***2,288,297***	***2,362,998***	***2,440,186***	***2,519,946***	***2,602,363***	***2,687,529***	***40,541,496***	***18,181,244***
8	**TOTAL O&M BENEFITS**	**0**	**232,285**	**1,462,721**	**1,510,015**	**1,558,874**	**1,609,351**	**1,661,500**	**1,715,376**	**1,771,039**	**1,828,548**	**1,887,966**	**1,949,356**	**2,012,785**	**2,078,321**	**2,146,036**	**2,216,003**	**2,288,297**	**2,362,998**	**2,440,186**	**2,519,946**	**2,602,363**	**2,687,529**	**40,541,496**	**18,181,244**
9	**CAPITAL ITEMS**																								
10	**Capital gains and other avoided purchases**																								
11	Avoided Failed Meter Purchases	0	129,022	814,965	835,650	856,897	878,720	901,137	924,165	947,822	972,126	997,096	1,022,751	1,049,111	1,076,198	1,104,031	1,132,634	1,162,028	1,192,238	1,223,286	1,255,199	1,288,000	1,321,718	**21,084,794**	**9,591,266**
12	***TOTAL - Efficiency gains and other avoided CAP***	0	129,022	814,965	835,650	856,897	878,720	901,137	924,165	947,822	972,126	997,096	1,022,751	1,049,111	1,076,198	1,104,031	1,132,634	1,162,028	1,192,238	1,223,286	1,255,199	1,288,000	1,321,718	***21,084,794***	***9,591,266***
13	**Avoided Meter Reading CAP Investment**																								
14	Walk Meter Reading Cost - CAP	0	0	0	831,922	0	0	0	0	0	0	0	0	0	1,166,722	0	0	0	0	0	0	0	0	**1,998,644**	**1,114,286**
15	***TOTAL - Avoided Meter Reading CAP Investment***	***0***	***0***	***0***	***831,922***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,166,722***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***1,998,644***	***1,114,286***
16	**TOTAL CAPITAL BENEFITS**	**0**	**129,022**	**814,965**	**1,667,572**	**856,897**	**878,720**	**901,137**	**924,165**	**947,822**	**972,126**	**997,096**	**1,022,751**	**1,049,111**	**2,242,920**	**1,104,031**	**1,132,634**	**1,162,028**	**1,192,238**	**1,223,286**	**1,255,199**	**1,288,000**	**1,321,718**	**23,083,438**	**10,705,552**
17																									
18	**GRAND TOTAL BENEFITS**	**0**	**361,308**	**2,277,686**	**3,177,587**	**2,415,771**	**2,488,071**	**2,562,637**	**2,639,542**	**2,718,861**	**2,800,674**	**2,885,062**	**2,972,107**	**3,061,896**	**4,321,241**	**3,250,067**	**3,348,637**	**3,450,326**	**3,555,236**	**3,663,473**	**3,775,145**	**3,890,364**	**4,009,246**	**63,624,934**	**28,886,796**

Southwestern Public Service Company

AMR Cost-Benefit Analysis

1	***SPS-NM -AMR-NPV***	**Total ($MM)**
2	**Benefits**	**19**
3	O&M Benefits	18
4	CAP Benefits	1
5	**Costs**	**(39)**
6	O&M Expense	(12)
7	Change in Revenue Requirements	(27)
8	**Benefit/Cost Ratio**	**0.50**