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# The Brattle Group Report:
# The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory

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

**PREPARED BY**

Ryan Hledik
Ahmad Faruqui
Pearl Donohoo-Vallett
Tony Lee

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THE **Brattle** GROUP

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# About the Authors

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**Ryan Hledik** is a Principal in The Brattle Group's New York office. He specializes in regulatory and planning matters related to the emergence of distributed energy technologies. Mr. Hledik received his M.S. in Management Science and Engineering from Stanford University, with a concentration in Energy Economics and Policy. He received his B.S. in Applied Science from the University of Pennsylvania, with minors in Economics and Mathematics.

**Ahmad Faruqui** is a Principal in The Brattle Group's San Francisco office. His areas of expertise include rate design, demand response, energy efficiency, distributed energy resources, advanced metering infrastructure, plug-in electric vehicles, energy storage, inter-fuel substitution, combined heat and power, microgrids, and demand forecasting. He holds B.A. and M.A. degrees from the University of Karachi in economics, an M.A. in agricultural economics and a Ph.D. in economics from The University of California, Davis.

**Pearl Donohoo-Vallett** is an Associate in The Brattle Group's Washington, D.C. office. She focuses on the increasing overlap of retail and wholesale regulatory issues with an emphasis on infrastructure investment and distributed energy resources. Dr. Donohoo-Vallett earned her Ph.D. in Technology, Management, and Policy and her S.M. in Technology and Policy from the Massachusetts Institute of Technology. She earned her B.S. in Mechanical Engineering from the Franklin W. Olin College of Engineering.

**Tony Lee** is a Senior Research Analyst in The Brattle Group's New York office. He supports clients on environmental policy analysis, wholesale market design, and economic analyses of generation, transmission and distributed energy resources. He holds Bachelor's Degrees in Economics and Engineering from Swarthmore College.

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# Executive Summary

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**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

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

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

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

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

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

## Findings

### Base Case

NSP currently has one of the largest DR portfolios in the country, with 850 MW of load curtailment capability (equivalent to roughly 10% of NSP's system peak). The portfolio primarily consists of an interruptible tariff program for medium and large C&I customers, and a residential

air-conditioning direct load control (DLC) program. The DLC program is transitioning from utilizing a conventional compressor switch technology to instead leveraging newer smart thermostats.

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

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

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

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

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

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

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

### High Sensitivity Case

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

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

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

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

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



| | 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 |

| | 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**
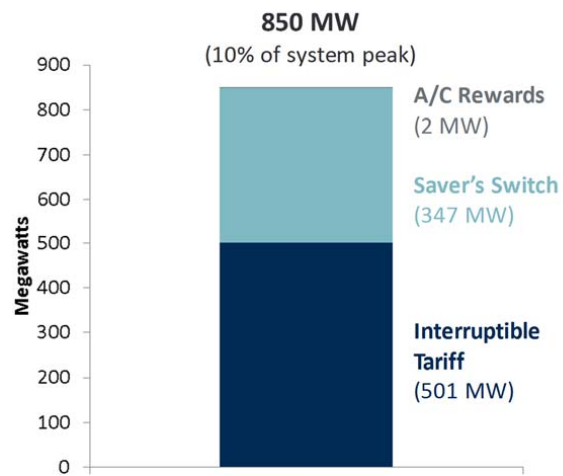


Sources: NSP 2017 DR program data and 2017 NSP system peak demand (8,546 MW)

## 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.

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

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

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

# II. Methodology

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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.

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[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**

| **①** **Parameterize DR programs** | **②** **Establish marginal costs and market depth** | **③** **Develop 8,760 hourly avoided costs** |
|---|---|---|
| • Build database of new flexible load programs<br>• Estimate per-participant costs and participation<br>• Identify value proposition and applicable grid services<br>• Establish load impacts and operational constraints | • Generation capacity value<br>• Frequency regulation value<br>• Average & targeted T&D value<br>• Energy value | Allocate marginal costs based on hourly LOLP \| Combine hourly costs to create stacked value profile |

| **④** **Optimally dispatch programs and calculate B/C metrics** | **⑤** **Identify cost-effective incentive and participation** | **⑥** **Estimate incremental cost-effective DR potential** |
|---|---|---|
| Simulate optimized hourly dispatch \| Calculate total benefits across value streams | Establish relationship between adoption and incentives \| Identify economic incentive level and associated participation | Calculate cost-effective potential by program \| Estimate portfolio impacts after participation overlap |

# 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.

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[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)**
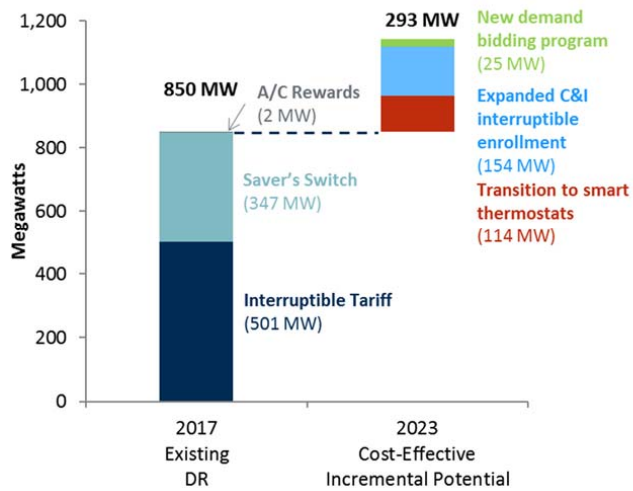


The incremental potential in conventional DR programs can be expressed as a "supply curve." Figure 6 illustrates the costs associated with achieving increasing levels of DR capability. The upward slope of the curve illustrates how DR capability (i.e., enrollment) increases as incentive payments increase. 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)**



293 MW of DR potential have an annualized cost of up to $59/kW-yr. This is roughly the value of avoided system costs after accounting for operational constraints of DR programs
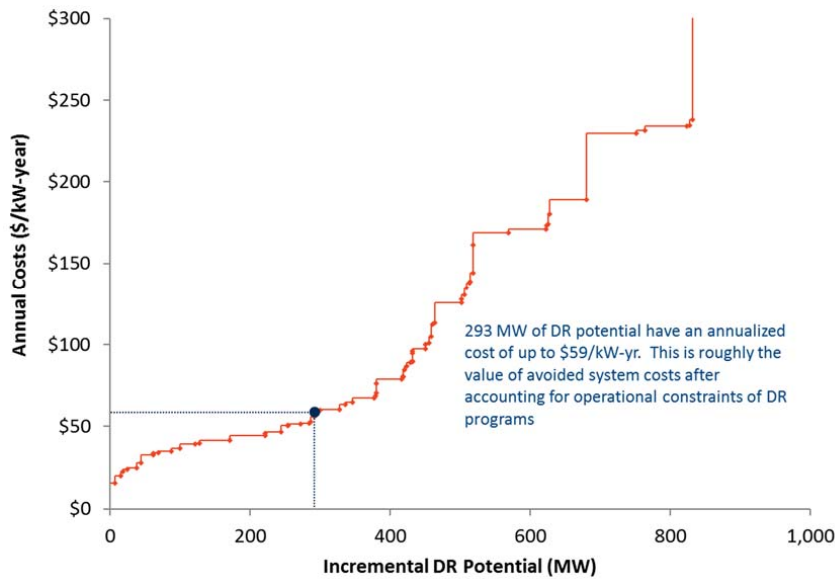
Note: Supply curve shows conventional DR potential without accounting for cost-effectiveness. Potential estimates if the DR options were offered simultaneously as part of a portfolio at each price point (i.e. accounts for overlap). Program costs presented in nominal terms.

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)**
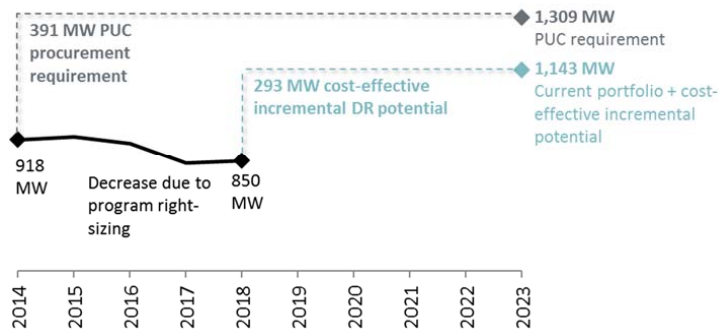


Note: Chart is scaled such that vertical axis does not start at zero. 391 MW procurement requirement is expressed at the generator level and is equivalent to 400 MW of DR capacity.

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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)**
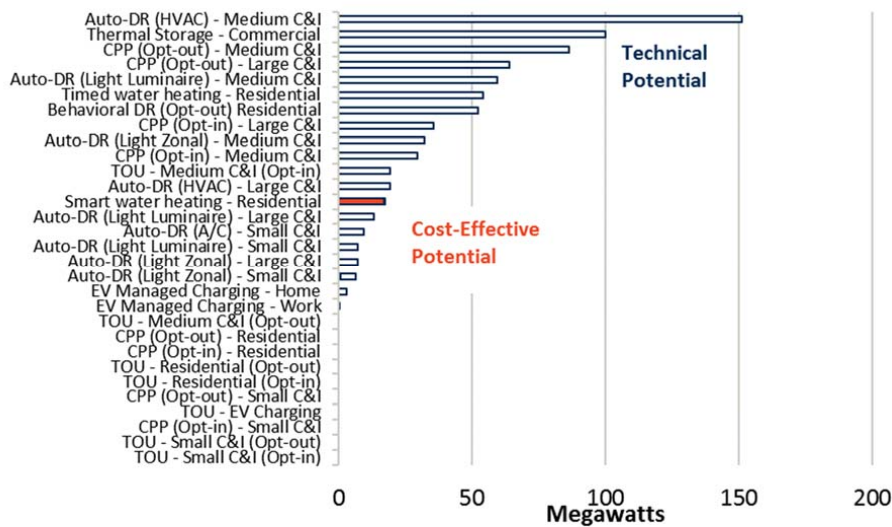


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

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)**
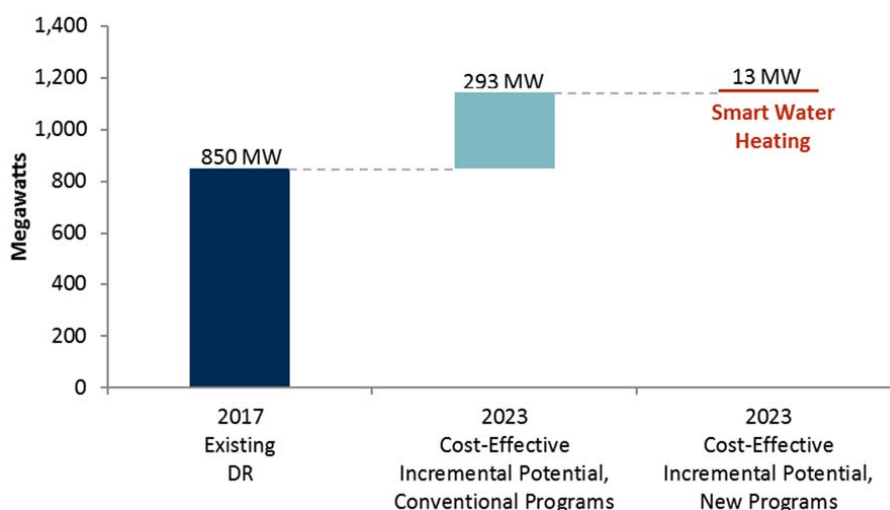


## Near-term Limitations on DR Value

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.

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

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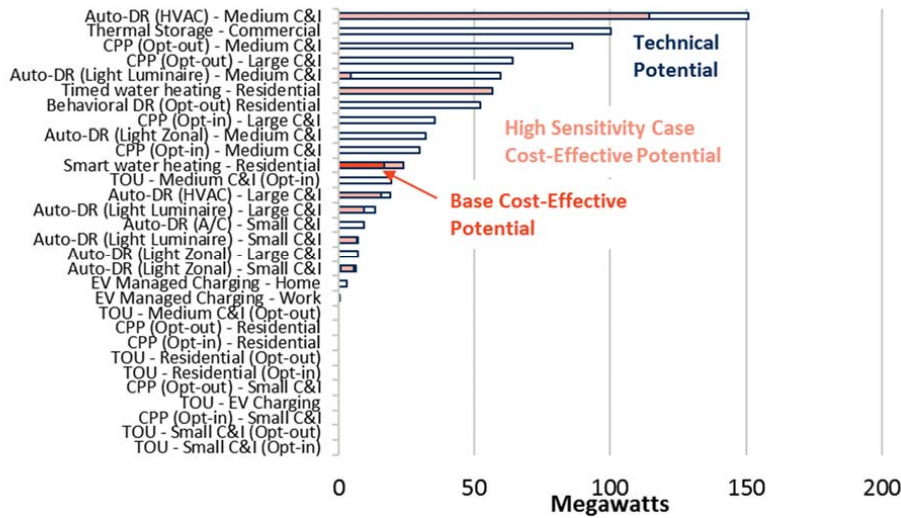


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

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

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

# V. Expanded DR Potential in 2030

## Base Case

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

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

**Figure 11: Cost-Effective DR Potential, Base Case**
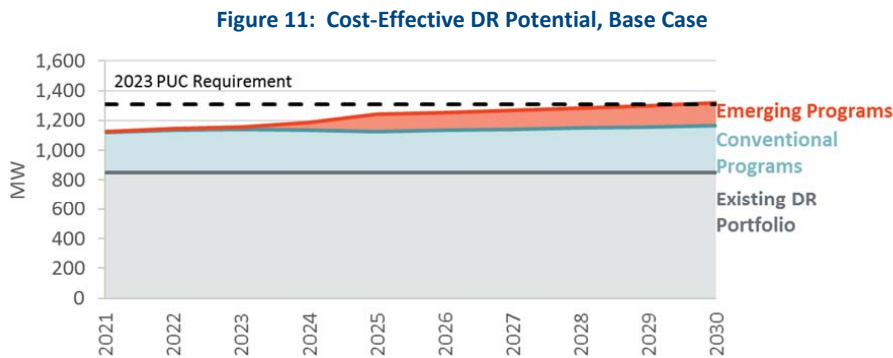


Under Base Case conditions, benefits of the DR program are primarily driven by avoided generation capacity costs. Avoided generation capacity costs account for $51 million of the $66 million (77 percent) in total annual benefits from the DR programs in the year 2030. This is because the relatively low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

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

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

*Notes:* Benefits shown in 2023 dollars.

# High Sensitivity Case

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

**Figure 12: New DR Program Potential in 2030**
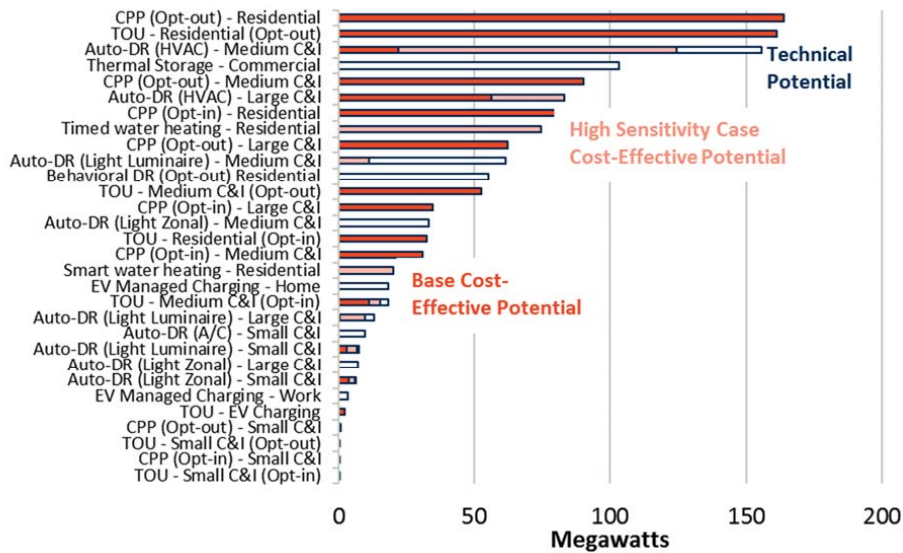


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

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

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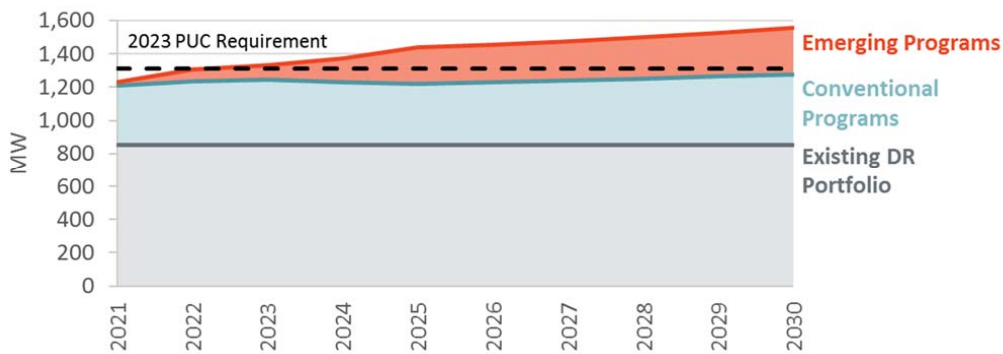


Over the longer-term, new policies could potentially drive down DR costs and therefore increase cost-effective potential. One initiative that has garnered some attention is the development of a technology standard known as "CTA-2045." CTA-2045 is a communications interface which would allow various control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

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

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

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

*Notes:* Benefits shown in 2023 dollars.

# DR Portfolio Operation

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

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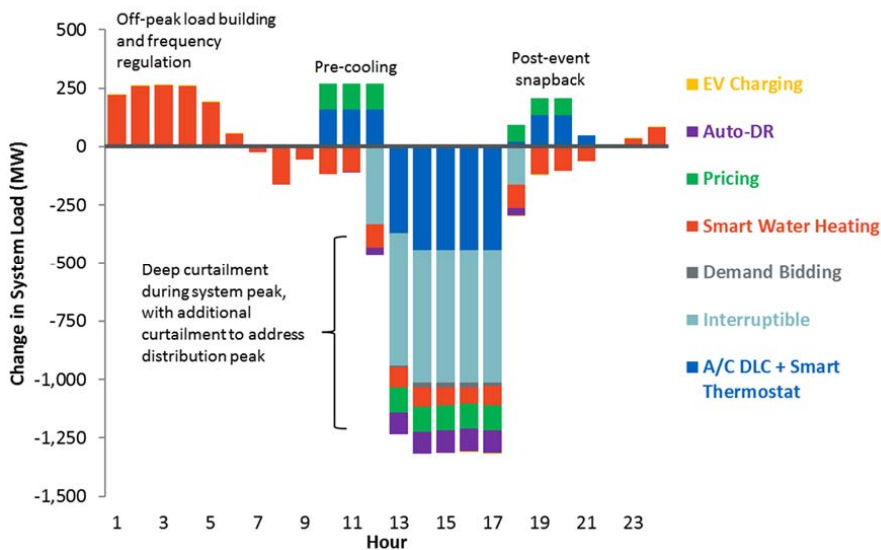


Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

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

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

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

**Figure 15: Average Impacts of the 2030 Cost-Effective DR Portfolio on NSP System Load (High Sensitivity Case)**
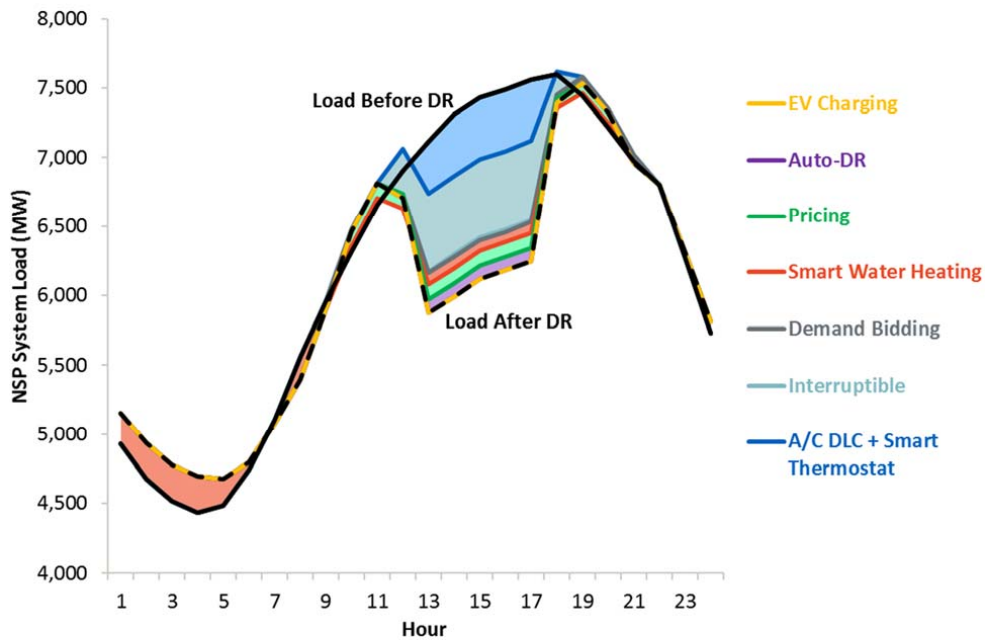
Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

# Sidebar: The Outlook for CTA-2045

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

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

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

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

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

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

# VI. Conclusions and Recommendations

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

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

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

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

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

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

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

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# Appendix A: Load*Flex* Modeling Methodology and Assumptions

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## 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**

| 1 — Parameterize DR programs | 2 — Establish marginal costs and market depth | 3 — Develop 8,760 hourly avoided costs |
| --- | --- | --- |
| • Build database of new flexible load programs<br>• Estimate per-participant costs and participation<br>• Identify value proposition and applicable grid services<br>• Establish load impacts and operational constraints | • Generation capacity value<br>• Frequency regulation value<br>• Average & targeted T&D value<br>• Energy value | Allocate marginal costs based on hourly LOLP / Combine hourly costs to create stacked value profile |

| 4 — Optimally dispatch programs and calculate B/C metrics | 5 — Identify cost-effective incentive and participation | 6 — Estimate incremental cost-effective DR potential |
| --- | --- | --- |
| Simulate optimized hourly dispatch / Calculate total benefits across value streams | Establish relationship between adoption and incentives / Identify economic incentive level and associated participation | Calculate cost-effective potential by program / Estimate portfolio impacts after participation overlap |

# 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

[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,

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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Continued from previous page

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

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

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

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

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

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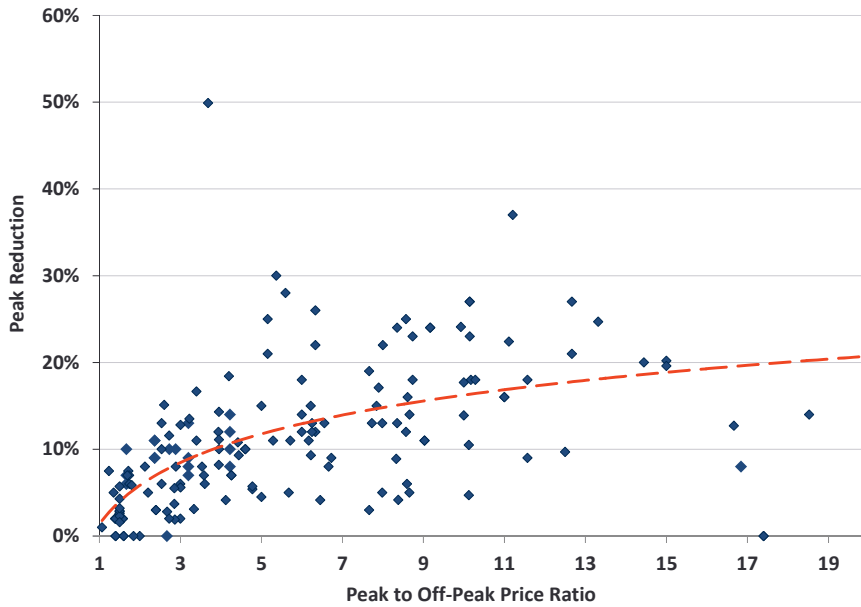


Results shown only for price ratios less than 20-to-1 and for treatments that did not include automating technology such as smart thermostats.

### Daily relationship between load reduction and load increase

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

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

### Tariff-related operational constraints

Most DR programs will have administrator-defined limits on the operation of the program. This includes the maximum number of hours per day that the program can be curtailed, whether or not those curtailment hours must be contiguous, and the maximum number of days per year with

allowed curtailment. Assumed operational constraints are based on Xcel Energy's program definitions and a review of common limitations from programs offered in other jurisdictions.

**Ancillary services availability**

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

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

**Table 6: DR Program Performance Characteristics**

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

*Notes:*

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

## Program Cost Characteristics

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

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

Notes:

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

**Table 8: 2030 High Sensitivity Case Program Cost Assumptions**

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

*Notes:*

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

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

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

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

**Avoided generation capacity costs**

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

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

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

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

**Table 9: Combustion Turbine Cost of New Entry Calculation**

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

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

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

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

### Avoided transmission capacity costs

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

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

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

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

### Avoided system-wide distribution capacity costs

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

### Geo-targeted distribution capacity costs

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

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

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

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

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

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

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

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

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

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

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

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



All capacity projects in 5-year distribution plan

Four filters are applied to identify candidate projects for deferral

1. Projects driven by demand growth
2. Projects with significant overall costs
3. Projects with sufficient customer load
4. Projects which address limited # of risks across feeders

**Candidate deferral projects:**
14 capacity projects totalling $14 million
135 MVA total capacity upgrade
38 MVA "load at risk" to be mitigated

## 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**
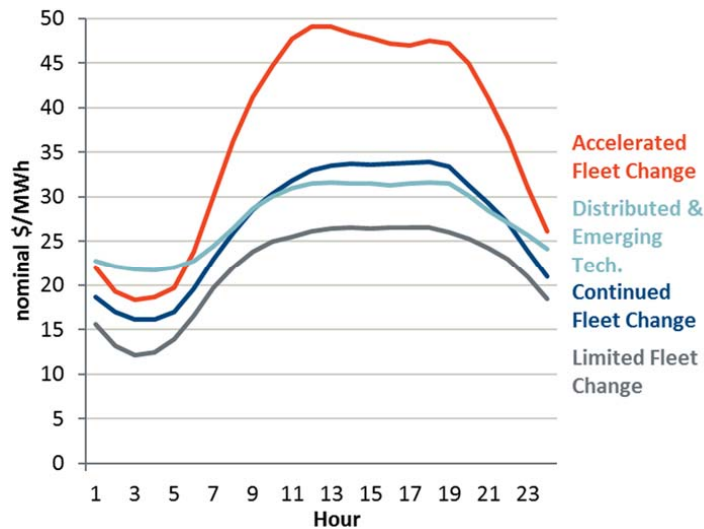


For the High Sensitivity Case, we relied on prices from the Accelerated Fleet Change (AFC) future. The AFC case has twice the amount of renewable generation capacity additions as the CFC future. However, increased load growth, accelerated coal retirements, and higher gas prices lead to overall higher 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

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[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**
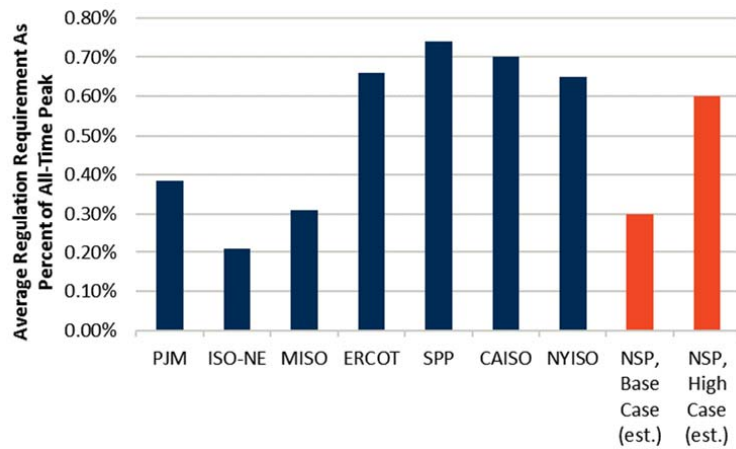


*Sources and Notes:* Values for wholesale markets extracted from PJM, "RTO/ISO Regulation Market Comparison", April 13, 2016. Orange bars for NSP assume that NSP's all-time peak is 8,335 MW at the customer level, based on three years of provided peak load data and assumed 8% line losses. Frequency regulation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

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[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)**
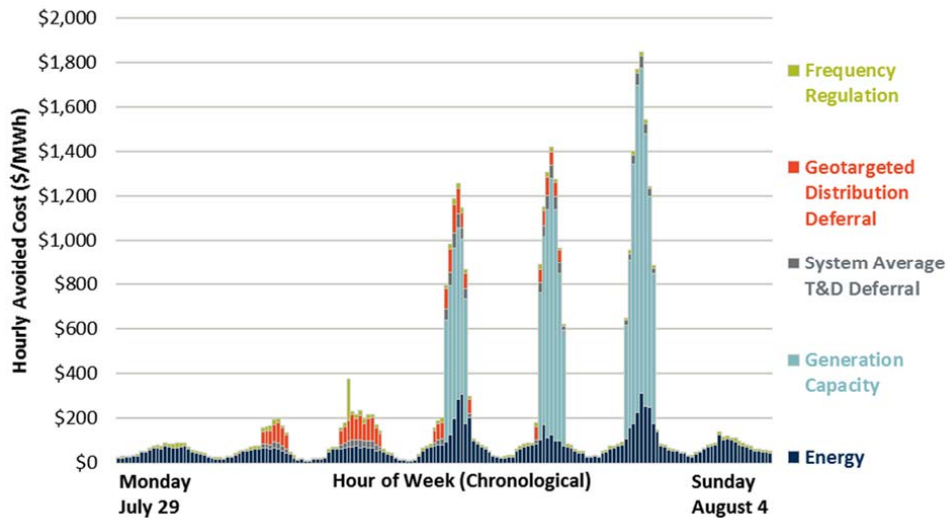


*Notes:* Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

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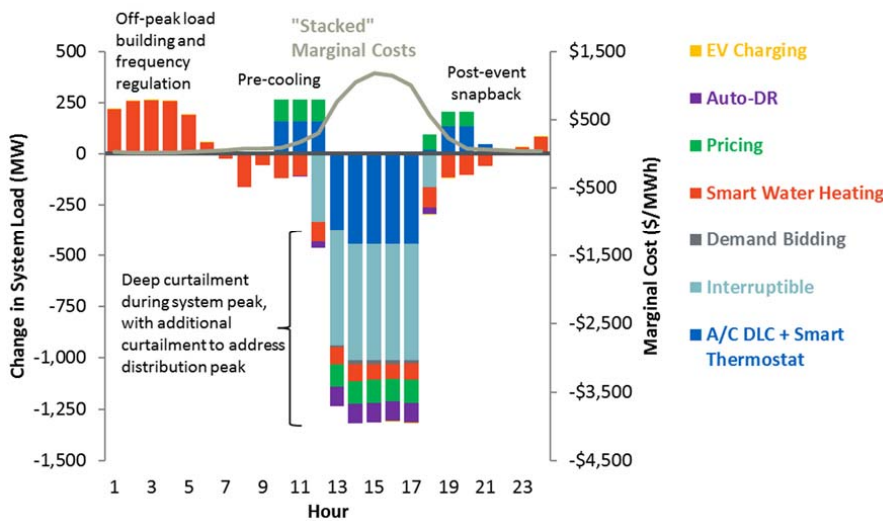
Through an iterative process, Load*Flex* determines when the need for a given value stream has been fully satisfied by DR in each hour, and excludes that value stream from that hour for incremental additions of DR. This ensures that DR is not over-supplying certain resources and being incorrectly credited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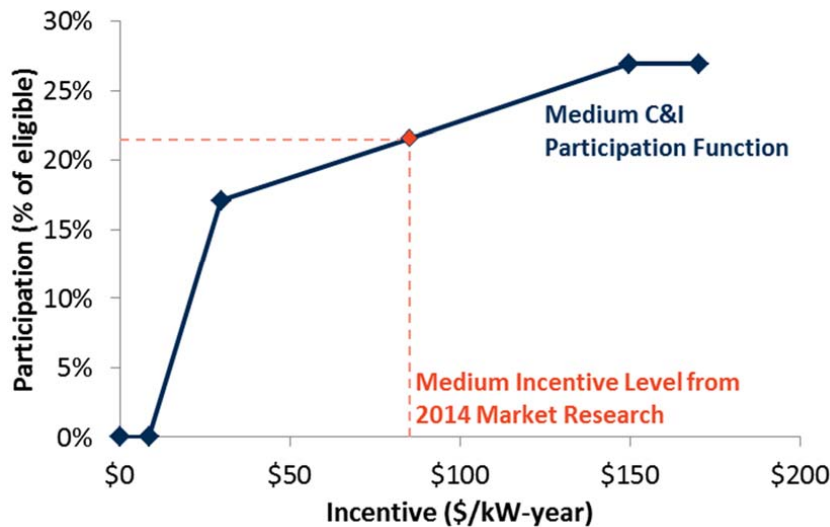


## Step 6: Estimate cost-effective DR potential

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

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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.

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[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.

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