APPENDIX G1 – DEMAND SIDE MANAGEMENT

I. INTRODUCTION

DSM is the modification of consumer demand for energy through various methods such as financial incentives and education. It enhances our customers' experience with energy (and energy management) by empowering them with the insights and technology to lower their energy bills. DSM also lowers the need for future generation resources and enables future CO_2 emissions reductions. DSM methods include educating customers on the benefits of purchasing energy-efficient equipment; providing customers with incentives to upgrade to more efficient equipment; encouraging participation in load management programs; and equipping customers with control systems to shift demand.

To date, DSM has largely been defined as energy efficiency and demand response. The future outlook and opportunities for DSM, however, are changing with declining cost effectiveness, increased deployment of renewables, expansion of new technology, and changing customer expectations. Future DSM opportunities will include utilizing new, integrated technologies to optimize DSM solutions by location and time while keeping costs low for customers.

There are fundamental differences between the benefits offered by traditional DSM and new technologies. Our traditional DSM resources focus on lowering energy savings through more efficient equipment and/or reducing peak demand on the hottest summer days. Many newer technologies (e.g. smart thermostats) also offer benefits beyond simply reducing overall and peak usage, including features that make it easier for customers to use energy during non-peak energy times when it is less expensive. Future demand response options will include technologies designed to proactively shift load during specific times of the day, controlling customer load in targeted locations facing peak conditions, and giving the Company the flexibility to control customer load as needed – further benefiting the operation of our generation mix and delivering cost savings to customers.

These evolving options require reconsidering the current approach to assessing the value of DSM investments. In order to incentivize our customers to embrace new flexible options, we will need to leverage and account for a range of benefits offered by new technologies, beyond energy reductions. The Company will need to provide incentives for automated energy management systems and other technologies that allow for flexible control and adjustment to load. Although DSM programs are generally approved through the Company's Conservation Improvement Program (CIP); recent decisions suggest that new enabling technologies largely fall outside the current parameters for recovery through CIP. In order to support new programs and opportunities to grow demand management through pilots, incentives, and/or rates for new energy solutions, the Company will need to find other avenues for cost recovery.

In the meantime, we are significantly expanding our commitment to achieving high levels of DSM savings, particularly with energy efficiency. The Preferred Plan increases our commitment to energy efficiency and includes savings, on average, of more than 700 GWh each year in permanent energy reduction. This commitment will help offset the need for future additional energy resources and our modeling confirms the cost effectiveness of these energy efficiency savings.

The Preferred Plan also complies with Commission direction to add an additional 400 MW of demand response by 2023.[1] But, making new demand response resources (or programs) cost-effective in the short term is challenging, and the Strategist modeling confirms this. First, based on our current resource mix, we are not forecasting a need for capacity for a number of years. Second, in the Preferred Plan, we also are not forecasting a need for a firm dispatchable resource until the 2030s. This limits the effectiveness of traditional demand-response resources because the primary benefit of these resources is avoiding peaking generation which is one of the options to meet the firm, dispatchable need.

The Company is firmly committed to innovation and the adoption of DSM in our plan, and we are committed to taking the following key steps:

- *Demand Response*: We are committed to securing an additional 400 MW of demand response by 2023; however, for a demand response portfolio to be successful, we need the flexibility to procure resources as needed to maximize all benefits – including benefits outside traditional demand response. Some additional demand response can be implemented through existing mechanisms. Other programs may require new cost-recovery opportunities, and we are committed to working with stakeholders to identify these. Additionally, we believe battery storage may be a resource we could use to meet demand response

[1] We note that when we first announced a Preferred Plan in May 2019, it did not include demand response additions because demand response was not the least-cost resource when compared to energy efficiency and solar resources. Based on feedback we received, however, and in light of the Commission's Order, we included cost-effective (though still not least cost) demand response resources in the Preferred Plan presented in this Resource Plan.

needs, and we propose allowing incremental storage to meet some portion of the 400 MW requirement.

- *Energy Efficiency*: We intend to aggressively pursue unprecedented energy efficiency savings levels outlined in our Preferred Plan that will achieve between 2-2.5% annual energy savings in the planning period. Estimated savings include utility sponsored programs as well as conservation occurring naturally in the market as a result of increasing efficiency options. Specific details regarding how the Company achieves energy efficiency is addressed in our various CIP Triennial Plans.

We look forward to working with our stakeholders to address some of the challenges presented in the remainder of this appendix and create more flexible paths to enable greater deployment of DSM resources. This will effectively position the Company to add more DSM in the future in a cost-effective manner.

II. DEMAND RESPONSE RESOURCES

Demand response resources generally can be grouped into two buckets: traditional and non-traditional resources:

1. ***Traditional demand response***, often referred to as load management, provides a temporary reduction to system peak. Often these products are referred to as dispatchable resources because the utility may control them directly. This peak reduction has a similar impact on our system as a combustion turbine (CT) because it can be brought on- and off-line quickly for short periods of time as an operational reserve.
2. ***Non-traditional demand response***, often referred to as demand management, provides the opportunity for our customers to plan for and manage their electric demand differently. Compared to traditional methods of peak demand reduction during the hottest days of year, these methods allow customers to shift portions of their electric loads to lower-cost periods of the day when carbon-free generation is highest. As noted by Lawrence Berkeley National Laboratory, in systems with high renewable penetration, demand management can unlock customer benefits like production cost savings of renewable resources.[2]

[2] Lawrence Berkley national Laboratory: 2025 California Demand Response Potential Study (Charting California's Demand Response Future), March 1, 2017. (http://www.cpuc.ca.gov/General.aspx?id=10622)

The Preferred Plan adds a significant amount of renewable resources and has little to no need for additional load-supporting resources (or peak reduction) in the near-term. Because a substantial portion of the value of demand response resources is the avoidance of load-supporting generation,[3] the cost-effectiveness of new demand response resources at this time is limited. If demand response were to be effectively used to avoid non-peaking generation, the hours during which the Company would need to control customer load would need to significantly increase. Our January 30, 2019 control event shows this impact as we moved from a traditional four-hour control period to a six-hour period requested by MISO during the reliability event. Meeting this extended duration was a challenge for many customers.[4] And, in the future, such reliability events could be even longer, possibly for days.

In the following section, we provide information about how the Company intends to meet specific demand response requirements for this Resource Plan as ordered by the Commission within this landscape. We also discuss the impact of emerging non-traditional demand response.

A. Integrated Resource Planning Requirements for Demand Response

The Commission's January 11, 2017, Order in Docket No. 15-21, at Order Point 10 and 14(e), states:

- Xcel shall acquire no less than 400 MW of additional demand response by 2023; and
- In its next resource plan filing, Xcel shall: …. 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.

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[3] The Brattle Group, The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, June 2019.

[4] The Company had a total of 1,770 Minnesota customers who were required to interrupt their controllable load throughout the six-hour event by maintaining a peak load at or below their firm service level, which is the Predetermined Demand Level (PDL) specified by each interruptible customer. A total of 931 of these customers did not fully comply with their load control requirement and had peak load that exceeded their PDL by at least one kW for all or a portion of the six-hour curtailment event.

The Commission's Order does not specify a basis for measuring the 400 MW. We have assumed this requirement to be a capacity equivalent number and therefore grossed up for line losses and reserve requirements. As noted in the Brattle Study, after accounting for reserve requirements, this is equivalent to 391 MW of generation (Gen. MW).

B. Stakeholder Engagement

In preparing for this Resource Plan, and in order to facilitate compliance with the Commission's Order, we engaged stakeholders early in order to obtain insights that could inform both the study details and future portfolio planning. The Company hired Great Plans Institute and the Center for Energy and Environment to lead seven demand response stakeholder discussions between December 2017 and January 2019. (The detailed minutes and results for this stakeholder engagement process can be found in the Demand Response Stakeholder Engagement Summary, Appendix G4.) In connection with this stakeholder process, we received valuable input regarding benefits associated with demand response, future design principles as we moves toward adjusting our demand response portfolio, products in development, and our overall strategic direction for demand response.

Stakeholders specifically identified three main design principles for programs and products that are being developed:

- Compensating demand response participants for the specific benefits provided to the utility;
- Ensuring pricing and expectations are clear, concise and transparent for customers; and
- Providing flexibility and options for customers.

Stakeholders also provided specific details they would like to see in ongoing filings for new demand response offerings. These include:

- Be clear about the outcomes that demand response offerings are designed to achieve and how those should be measured down the road;
- Fully evaluate demand response program costs and benefits;
- Address reliability and resilience of demand response offerings, as relevant;
- Delineate between dispatchable and non-dispatchable demand response; and
- Show transparency toward meeting the objectives listed above.

The Company intends to focus on these details established by stakeholders as we request approval of new and expanded programs from the Department and/or Commission.

C. Potential Study Analysis

Also in preparing our Resource Plan, we engaged The Brattle Group to analyze the benefits of demand response. The Brattle Group's report, *The Potential for Load Flexibility in Xcel Energy's Northern States Power Territory* ("2019 Potential Study"), included as Appendix G2, estimated the potential capabilities of cost-effective demand response that could be deployed in Xcel Energy's Northern States Power service territory, including Minnesota, North Dakota, South Dakota, and Wisconsin. The study focused on the addition of non-traditional (non-conventional) demand response resources. The study did not, however, address incremental demand from existing customers or the impact of customers limiting or ceasing participation in the future. In other words, existing program participation was a constant value.

The Brattle Group concludes the following from their analysis:

1) The largest benefit from demand response continues to be avoided generation capacity cost;
2) Xcel Energy could grow demand response resources by 293 Gen. MW at an annual cost of up to $59/kW per year for traditional demand response resources by 2023;
3) Cost-effective non-traditional demand response could be used to further grow peak reduction by 13 Gen. MW, increasing the cost-effective potential for incremental demand response to 306 Gen. MW; and
4) In 2025, the potential cost-effective demand response increases by an additional 87 Gen. MW, driven by the ability to offer time-varying rates.

1. Demand Response Benefits

The 2019 Potential Study accounted for cost benefits that are commonly included in assessments of traditional demand response, based on reductions in system peak demand:

- Avoided generation capacity costs – reduced need for new peaking capacity;
- Reduced peak energy costs – reduced load during high-priced peak periods; and
- System-wide deferral of transmission and distribution – reduced need for peak-driven upgrades in transmission and distribution capacity.

The study also identified additional benefits that may be achievable with advanced non-traditional demand response products:

- Geotargeted distribution capacity investment deferral – targeted demand response investments where load reductions would defer localized needs for capacity upgrades;
- Ancillary services – e.g., real-time adjustments to load from some end-use applications to mitigate system imbalances; and
- Load building/valley filling – shifting on-peak load to off-peak hours.[5]

The 2019 Potential Study compared potential benefits as a result of increased demand response to the additional resource need for a CT (the resource used for avoided generation comparison) to analyze cost-effectiveness. The flex model, also used as part of the analysis, extended the potential benefits for demand response to include additional values outside this traditional avoided generation (such as ancillary services noted above). By adding these benefits, the 2019 Potential Study was able to determine what additional value demand response could provide, and if these too would impact cost-effectiveness. The study found these new values account for approximately 20 percent of the total benefits today. However, as a result of the Resource Plan analysis, the need for a CT (or other load supporting resources) now extends beyond this planning period. This impacts the modeled cost-effectiveness of traditional demand response resources and is not reflected in the 2019 Potential Study.

The 2019 Potential Study also reviewed potential benefits (frequency regulation, transmission and distribution deferral, etc.) in a high sensitivity analysis that included high renewable penetration. As highlighted below in Figure 1, even under the high-sensitivity case, 75 percent of the demand response benefits projected in 2030 were tied to the avoidance of new generation capacity in 2030. The remaining benefits include energy cost reductions, transmission and distribution deferral, and frequency regulation.[6]

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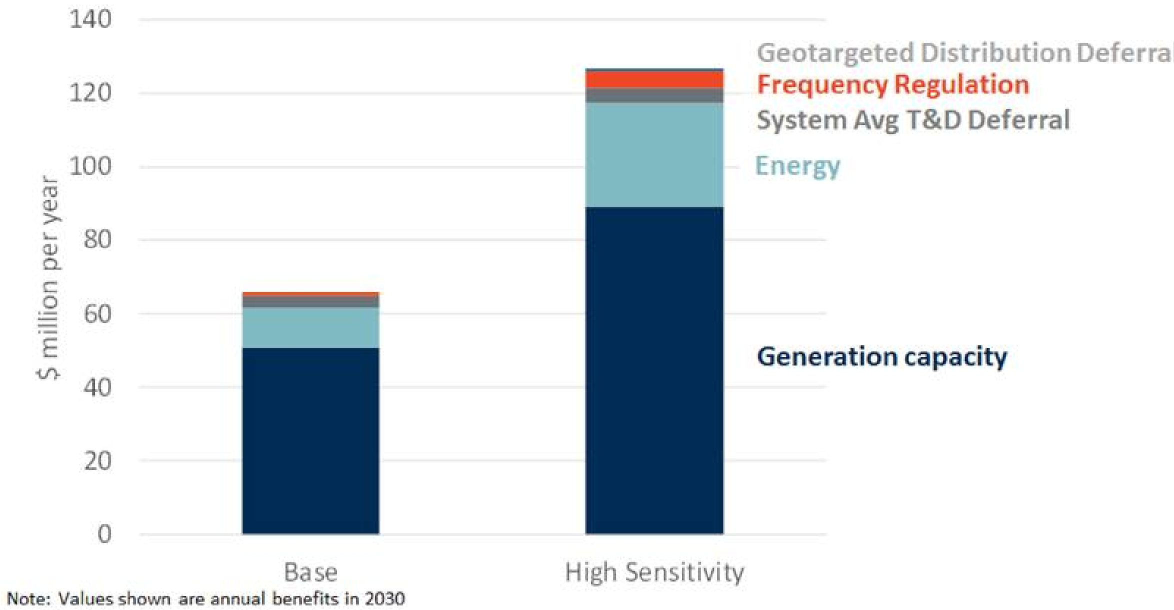
[5] The Brattle Group, The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, June 2019, pages 7-8.

[6] Frequency regulation allows utilities to provide market-based compensation to resources that have the ability to adjust output or consumption in response to an automated signal helping manage generation to demand.

Figure 1: Demand Response Avoided Cost Benefits (2030)[7]



This analysis provides two key takeaways: (1) traditional demand response as a cost-effective resource is highly contingent on the need to reduce and avoid generation capacity (e.g. a CT); and, (2) when more renewables exist within the utility's resource mix (as in the high-sensitivity case), the benefits of demand response shift to include more products and services that help integrate renewable resources, focusing on energy, transmission and distribution deferral, and ancillary services as shown in the analysis of the high sensitivity.

2. *Avoided Generation Comparison*

The 2019 Potential Study compared the cost of demand response against a CT. CTs are load-supporting units with relatively high variable costs; they typically run up to a few hundred hours of the year when electricity demand is very high and/or there are system reliability concerns. Demand response programs are typically limited to less than 100

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[7] *The Potential for Load Flexibility in the NSP Service Territory,* Study Overview Presentation. Presented by Ryan Hledik, Amhmad Farugui and Tony Lee, Demand Response Workgroup Meeting #7, January 22, 2019.

hours a year to avoid customer fatigue and limit program drop-outs.[8] In contrast, new intermediate or baseload capacity (e.g., a gas-fired combined cycle plant) has a higher capital cost and lower variable cost than a CT, and therefore will run thousands of hours per year. Traditional demand response tools 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 involves permanent load reduction that applies to a much broader range of hours.[9] We explored the operational constraints of demand response programs in late 2017 and found that, in order to achieve larger load reductions, demand response needs to be dispatched during more hours of the year.[10] An increased target for demand response, for example, could require the Company to control many different hours of the day on multiple consecutive days in a given year.[11] But, this level of control would likely be unsustainable given customer fatigue anticipated with multiple events.

3. Cost-Effective Demand Response Potential - 2023

Under base case assumptions,[12] the study found that the Company could not approach the 2023 procurement requirement of 391 Gen. MW with cost-effective demand response until after 2025.

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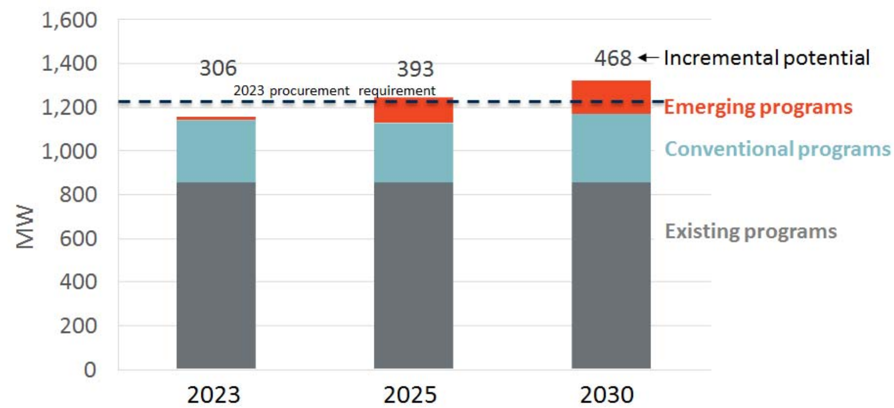
[8] *The Cost-Effectiveness of Demand Response in NSP's Service Territory*, Presented by Ryan Hledik, Amhmad Farugui and Tony Lee, December 2017. Slide 15. *See* Appendix G3.
[9] *Id.*
[10] *Id.*
[11] *Id.* at slide 40.
[12] As opposed to "high sensitivity" assumptions, which include higher assumed generation capacity cost, more volatile energy prices, significant reductions in emerging demand response technology costs, and increased need for frequency regulation.

Figure 2: Cost-effective Demand Response Potential[13]



The cost-effective opportunities identified in the study include 293 Gen. MW of incremental traditional demand response and 13 Gen. MW of incremental non-traditional demand response for a total of 306 Gen. MW. As noted above, this study did not consider expanding current customer load and is not reflective of how current customers may participate in future demand response offerings. The specific opportunities identified in the study include:

- *Traditional Demand Response potential*: This potential includes expanding our A/C Rewards program, continuing to grow Saver's Switch, and expanding commercial interruptible load. We note that expanding interruptible load is not expanding participation in current programs, but rather creating new programs to reach additional customers.
- *Non-Traditional Demand Response potential:* This potential includes smart water heating control (both thermal storage and peak control) for customers with existing electric water heaters.

As discussed below, we have included all cost-effective demand response identified in the 2019 Potential Study as part of the Preferred Plan, despite the modeling results.

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13 *The Potential for Load Flexibility in the NSP Service Territory,* Study Overview Presentation. Presented by Ryan Hledik, Amhmad Farugui and Tony Lee, Demand Response Workgroup Meeting #7, January 22, 2019.

4. *Cost-Effective Demand Response Potential - 2025*

The Commission's January 11, 2017, Order required the Company to provide a full and thorough cost-effectiveness study to take into account the achievability of 1,000 MW of additional resources by 2025. As shown in Figure 1, our analysis showed this was not a cost-effective option and highly dependent upon resource needs. Cost-effective demand response at any such significant level of investment would need to include an increase in additional benefits (such as those defined above) and new enabling technologies, such as smart meters.

The 2019 Potential Study assumed full deployment of smart meters by the year 2024. We clarify that the analysis of cost-effectiveness did not include the cost of the advanced meters themselves; it did however, include some costs, such as the cost to integrate the information from the advanced meters to the systems necessary to achieve identified program objectives. Advanced meters provide an increased ability to increase demand savings for customers on time-varying rates, such as time of use and critical peak pricing. In the 2019 Potential Study, scenarios involving opt-out rates to customers showed an increase in demand savings. However, the potential increase in savings under these types of scenarios is highly dependent upon customer interest and, in the case of time of use, customer behavior. Therefore, there is only a minimal increase in potential for these programs.

While these resources were not identified as cost-effective in the study until later years in the Resource Plan, we continue to explore their impact and how to further increase non-traditional options. Additional information regarding the actions the Company intends to take to procure these resources is included in the "Action Plan" section below. For additional information specific to the Strategist modeling and the inclusion of these resources, please see Appendix F2 and F3.

D. Changes in Demand Response Technologies

The NSP electric generation system is evolving. The addition of significant carbon-free renewable generation resources will change the future value and focus of demand response:

- Significant solar additions that are highly coincident with historical peaking conditions will limit the need for new load-supporting generation;
- Solar and wind additions may produce energy that meets or exceeds load, resulting in energy cost savings opportunities and increased carbon reductions throughout the year by shifting load to match periods of excess renewable generation.

New demand response technologies and programs that respond to these conditions are defined as demand management – the management of load within a customer's home and/or business. Unlike traditional demand-response tools that reduce load during the hottest days of the year, these resources move energy usage from peak periods to off-peak periods throughout the year. Non-traditional demand response will be an important part of our energy future. However, the traditional model for cost recovery of demand response is an impediment to the growth of these resources, and a new cost-recovery mechanism needs to be devised – either through a reinterpretation of the CIP statute, a legislative change, or some other means.

Demand management can help operationalize the future energy grid to maximize the benefits of intermittent resources like wind and solar generation more effectively. Examples of possible programs that would fit into this category include auto-DR (customer energy management systems that include event-based controls and that facilitate shifting load to lower usage and lower carbon times), time varying rates (including time-of-use and critical peak pricing), thermal energy storage (e.g., grid-enabled electric water heaters), and reverse demand response (utilizing excess renewable resources in the middle of the afternoon to help maintain optimal grid operation). These technologies could bring benefits beyond curbing the need for capacity generation and include system-wide deferral of transmission and distribution, geotargeted distribution capacity investment deferral, ancillary services, and load building/valley filling.

We will need to undertake significant efforts to identify and implement programs and technologies that cost-effectively produce these benefits. Among other things, we will need to produce more sophisticated modeling methods to determine the benefits at a variety of generation conditions; develop customer programs to optimally operate a variety of end-use technologies under new conditions; run pilots with limited customer groups to determine cost-effectiveness; and eventually pursue cost-effective programs at scale. But, these efforts will be worthwhile. By implementing new demand management opportunities, we will be prepared to maximize benefits for customers during the clean energy transition over the next 10-20 years, as resource flexibility and planning for operational constraints take center stage.

Although many non-traditional demand-response opportunities require future enabling technology, we are beginning to explore options today. We are developing pilots for customers to manage their demand and will soon launch our pilot to assess time-varying rates. Another example is grid-enabled water heaters (also known as smart electric water heaters), which allow customers and utilities to control the electricity used to heat residential domestic water. When enabled, these water heaters can act as traditional demand-response tools, allowing utilities to turn off the water heaters during high-demand periods and turn them back on to run during the night. The smart water heaters also can act as demand management tools, allowing customers to primarily use electricity generated overnight to heat water, and then leverage the water heater tanks' thermal storage abilities to retain heat throughout the day and provide hot water during periods when energy prices are higher.

Although the 2019 Potential Study found this to be a promising enabling technology, incentives for thermal storage capabilities do not qualify under CIP, as recently determined by the Department.[14] Instead, we have requested approval to include grid-enabled water heaters as part of our traditional demand response portfolio (as part of our Saver's Switch program) in our 2020 CIP Extension Plan without incentivizing the thermal storage capabilities. Therefore, the savings reflected in the 2020 Plan Extension are much smaller than those predicted by the 2019 Potential Study, amounting to less than one megawatt per year for the emergency use of these systems. (If the thermal storage capabilities also were recognized, the savings could be 13 Gen. MW by 2023.)[15]

The Department has recently stated that, in order to qualify under CIP load-shifting opportunities need to reduce overall energy use at the customer meter.[16] In the case of grid-enabled water heaters, leveraging the use of thermal storage shifts energy use to off peak periods, but does not necessarily cause an overall reduction in energy use at the customer meter.

As another example of limitations for demand response, the Company recently has met challenges in providing incentives for customers to purchase ENERGY STAR-certified Level 2 electric vehicle "smart" chargers and participate in efficient, time-controlled charging (during off-peak nighttime hours).[17]

These decisions directly underscore some of the significant challenges facing the Company as we work to advance our demand-response portfolio with pilots and

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[14] See, e.g., Docket No. E,G002/CIP-16-115, Department of Commerce Decision (September 13, 2018).
[15] The Company has included 13 Gen. MW in our action plan based on the assumption that some recovery mechanism will be put into place by 2023.
[16] See, e.g. Docket No. E,G002/CIP-16-115, Department of Commerce Decision (June 12, 2019). Which states in part that "demand-side management energy savings were required" meaning that energy savings at the customer meter were required to qualify for funding under CIP Recovery.
[17] See Docket No. E,G002/CIP-16-115, Department of Commerce Decision, (June 12 2019).

customer incentives that can unlock demand-side resources to more effectively manage our system and facilitate the integration of renewable resources. Programs such as these should be part of our resource pool, but in order to include them, the Company must first be able to provide incentives to customers and receive recovery of these costs. The current options available to the Company are limited at this time.

- *CIP Rider Recovery (Minn. Stat. §216B.241)*: As noted above, under the existing statutory requirements, recovering demand management programs through CIP is unlikely. The language of the statute could be modified to support demand management, but would take a legislative change.
- *Base-Rate Recovery*: Recovering the costs of customer incentives for demand management would require a full understanding of customer interest and future enabling technologies when forecasting test years. At this time, as technologies are evolving quickly, it is difficult to forecast costs over the course of a multi-year rate plan. A more agile cost recovery mechanism is needed to address changes in technology and customer demand.
- *Other Rider Recovery:* There are currently no other riders (or enabling legislation) that specifically support recovery of demand management investments.

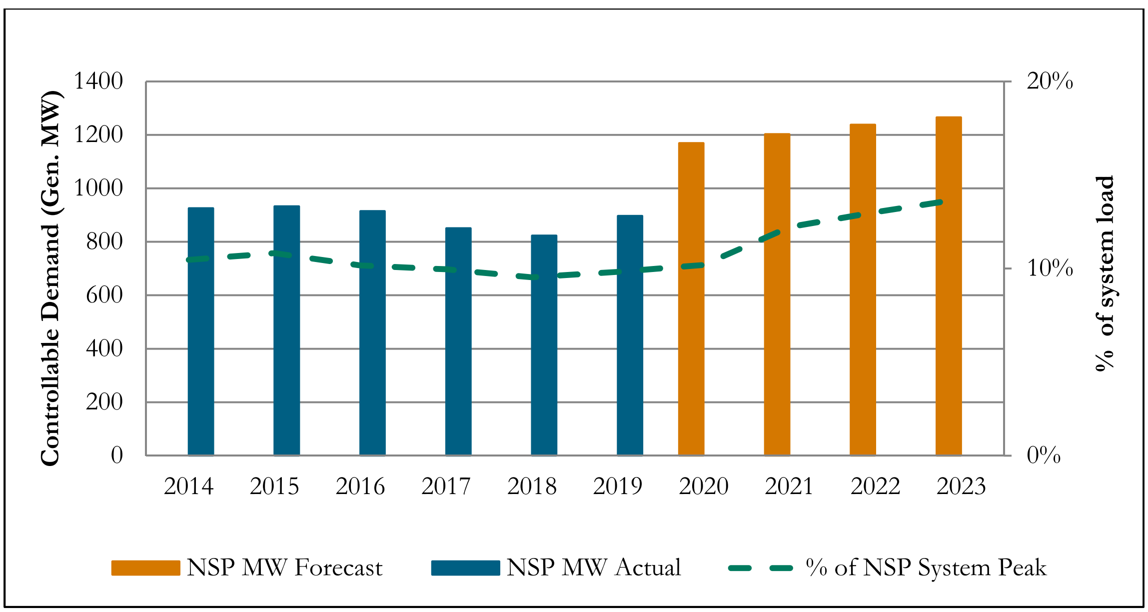
We believe that, if piloted and funded through an appropriate mechanism, these efforts would help the Company reach the commitment established in our Preferred Plan in the most cost-effective and sustainable fashion. The Company intends to continue to explore future recovery despite the challenges identified herein.

III. DEMAND RESPONSE ACTION PLAN

Our Preferred Plan includes 1,310 MW (1,266 Gen. MW) of demand response resources as part of our five year planning period. This is a significant increase in demand response for the Company, representing 14 percent of our peak load. Figure 3 below shows the demand response resources included in the Strategist modeling as part of our Preferred Plan. The Company optimized and tested traditional demand response as though it were a competitive supply-side option. We performed this modeling using several differing approaches and creating three bundles for analysis. However, the model did not choose additional demand response under any of these approaches because it never modeled as the least cost "supply-side" resource available compared to other resources such as energy efficiency and solar additions. Nonetheless, based on the Commission's Order, we include sufficient demand response additions in the Preferred Plan to comply with the requirement that the Company acquire no less than 400 MW of additional capacity-equivalent demand response by 2023. In order to meet this requirement, we plan to both increase traditional demand response resources over the next several years (including through new programs that are dependent upon the regulatory process and customer acceptance), and explore non-traditional demand response resources.

The generic demand response bundles that were evaluated as supply-side options in our modeling were developed immediately after receiving the 2019 Potential Study and before we finalized a detailed implementation plan for acquiring the incremental 400 MW. The values included in the modeling and shown in Figure 3 served as a generic representation of general demand response additions designed to achieve 400 MW of demand response additions by 2023. Although these values are directionally consistent with our plans for demand response additions discussed in this appendix, they do not perfectly align. For example, we do not believe that we will procure a large increment of additional demand response in 2020 as reflected in the modeling. Rather, in reality, these additions will occur over time as we approach 2023, as laid out in the following sections. Because the Strategist model is generally intended to be used to help identify size, type and timing of new resources at a high level, we believe the degree to which the values in our Strategist modeling and the action plan differ is acceptable.

Figure 3: Controllable Demand (Gen. MW)



In this section, we provide further information regarding the Company's five-year action plan established to meet the resources identified in the Preferred Plan, and how this action plan increased demand response by 400 MW by 2023.

Before discussing specific programs, however, we believe it is important to emphasize the challenges in launching and marketing demand response programs sufficient to meet the Commission's target of 400 MW by 2023. First, any program we launch is subject to variances in customer adoption and use of new technologies. Demand response originally was intended to control system demand over several hours across several days throughout the summer, program dependent. As we develop new cost-effective customer programs or technology options, customer incentives will need to be aligned with the specific value provided to the system. Large discounts based only on summer afternoon load reduction forecasts will not continue to be impactful to our changing system. Instead, these programs will need to account for many events being called throughout the year, as illustrated in our discussion of the reliability requirement, which highlights the need for firm dispatchable resources particularly in winter. These increased expectations will impact customer participation. Additionally, the technological ability to control customer usage or communicate to customers in real-time is critical to the effectiveness of these technologies. Enabling technology in future programs should allow customers to participate in more events with fewer impacts to their normal operations/comfort.

Second, the current regulatory process also is a challenge for demand response. As noted above, CIP programs require energy savings, which is not the main benefit of demand response efforts. The cadence of rate cases also is not ideal for providing our customers with new demand response options. Therefore, we must look to other sources, particularly to account for the benefits from the next generation of demand management program/customer offerings.

Notwithstanding these challenges, the Company is committed to adding 400 MW of demand response by 2023, and we discuss our plans for reaching this goal below.

A. Five-Year Action Plan

Our action plan consists of three tracks: (1) expansion of existing programs where appropriate, (2) addition of new traditional programs and tariffs, and (3) addition of non-traditional opportunities. Some of these products have not yet been approved by the Commission or Department and will need to be reviewed in these forums prior to our ability to offer them to customers.

Table 1 shows our action plan by three categories, those impacting existing products, expanded and new programs (2020 programs and 2021 programs) and non-traditional demand response opportunities.

Table 1: Demand Response Five-Year Action Plan

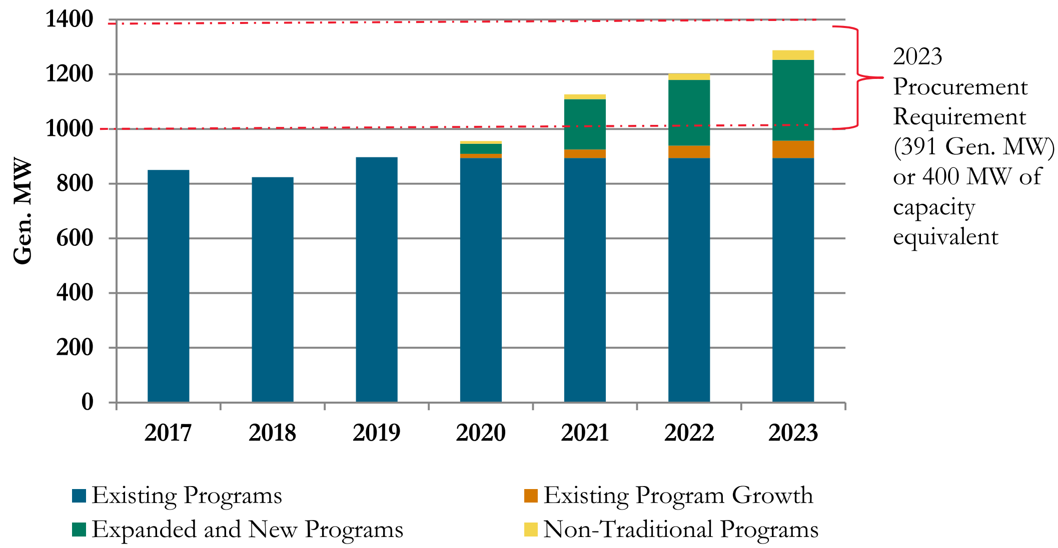
	Program	Regulatory Path	Status	Actuals[18] 2019	Estimated Cumulative Potential (Gen. MW) 2019	2020	2021	2022	2023
Existing Programs	Electric Rate Savings	CIP (admin); Rate Case (discounts)	Existing Program	461	-	462	464	465	466
	Saver's Switch	CIP (admin); Rate Case (discounts)	Existing Program	433	-	447	461	474	491
	Subtotal Existing			**894**	**-**	**909**	**925**	**939**	**957**
Expanded and New Programs	A/C Rewards (Smart Thermostats)	CIP	Modified in 2020 Extension Plan	3	13	23	98	103	114
	Small Business Smart Thermostats	CIP	Testing –Summer 2019; 2021-2023 Triennial Plan Filing	0	0	0	1	2	3
	Peak Partner Rewards	CIP	2020 Extension Plan	0	0	14	45	45	45
	Two way switches – Saver's Switch Technology Update	CIP	2021-2023 Triennial Plan Filing	0	0	0	0	0	19
	Interruptible Tariff(s)	Rate Cast or Miscellaneous Filing	In design - Tariff Filing 2019/2020	0	0	0	40	90	115
	Subtotal Expanded and New			**3**	**13**	**37**	**184**	**240**	**296**
Non-Traditional Programs	Grid Enabled Electric Water Heaters	Non-Traditional - TBD	In design	0	0	0	4	9	13
	Commercial Building Controls (Auto DR)	Non-Traditional - TBD	In design - Currently not cost-effective[19]	0	0	10	13	15	22
	Other	Non-Traditional-TBD	In design	-	-	-	-	-	-
	Subtotal Non-Traditional			**0**	**0**	**10**	**17**	**24**	**35**

	2019	2019	2020	2021	2022	2023
Total Existing, Expanded, New, and Non-Traditional Programs	**897**	**907**	**956**	**1,126**	**1,203**	**1,288**
Incremental Program Capacity (Gen. MW)	-	-	-	-	-	**391**
Incremental Program Capacity with Reserve Margin (MW)	-	-	-	-	-	**400**

[18] Actual data represents what is available in the field for load control in 2019. While there may be additional load added we represent it as 2020 load within this chart.
[19] Commercial Building Controls (Auto DR) was not modeled in the 2019 Potential Study as cost-effective. We have assumed these estimates based on 1/2 of the technical potential available (accounting for potential overlap with other programs). The cost-effectiveness is largely dependent upon system and integration costs the Company believes will come down in the next several years.

Figure 4 provides a graphical representation of the growth in demand response within these categories. We project the total demand response resources available in 2023 to be 1,288 MW in our Action Plan. This is slightly higher than, but directionally consistent with, the 1,266 of demand savings modeled in the Preferred Plan.

Figure 4: Future Demand Response Growth in 5-Year Planning Period



1. *Existing Load Availability*

In setting a baseline for projecting future growth in demand response programs, we first look to our estimates of load availability through existing programs. Load availability is highly dependent upon two factors: customer interest and load estimates per customer as defined by the Company's measurement and verification of demand response. As shown in Figure 3, commercial load availability decreased between 2016 and 2018. Customer interest played a significant role in this decrease. We gave customers the opportunity to adjust their contracts prior to future required control testing. Customers could opt out of their contracts prior to their completion date or adjust their demand levels.[20] Many customers adjusted their contracts for our Electric

[20] See, Compliance Filing Energy Rate Savings (ERS) Tariff Waiver, Docket No. E002/M-15-189, (March 29, 2016).

Rate Savings program during this time. This resulted in a drop of estimated available load to approximately 824 Gen. MW in 2018.[21]

We determine the second factor of estimated load availability by measurement and verification of tools in the field. This process resulted in an increase to available load in 2019. Our measurement and verification process includes actual testing events for residential and commercial Saver's Switch including data logging and statistical evaluation of signal reception rates (how often the switch can hear our message). An average five-year analysis of these reception rates results in our estimation of load per switch. Our measurement and verification results in 2018 showed an increase in these rates that appears to correspond to an addition of approximately 70,000 replacement switches put in place in the previous five-year period.[22] This increase in load per switch plus increase in participation resulted in a substantial increase in available load through the Saver's Switch program. This resulted in an increase in estimated available load of approximately 73 MW in 2019. This increase offsets some of the decreases in estimated available load due to changes in participation in our Electric Rate Savings program discussed above.

For purposes of meeting the Commission's Order to acquire 400 MW of additional demand response by 2023, we have interpreted additional demand response to include increases in available load from all sources, including new programs and participation, increased load availability of current customers, and adjustments in calculations of load availability based on measurement and verification. We calculated the addition of 400 MW of capacity equivalent demand response from a baseline set at 2019 levels, which are generally consistent with the average levels of demand reduction for the past five years, including 2017 when the Commission's Order was issued.

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[21] We note this number differs from the 850 MW noted in the 2019 Potential Study. The 850 MW figure was a forecast based on data from 2017. The Company now has more accurate information about the actual results for 2018.

[22] Beginning in 2004, the Company invested in smart switches that allowed for adaptive algorithms. All residential and business participants, as well as all switches replaced for maintenance purpose receive the adaptive algorithm switch. These details are discussed in our annual compliance filing for Saver's Switch filed in Dockets No. E002/M-01-46 & E002/CI-01-1024 on February 14.

2. *Existing Product Growth*

The Company has had a robust traditional demand response portfolio since the early 1990s. Our portfolio is the eighth largest among all US investor-owned utilities (IOUs) when demand response is expressed as a percentage of peak demand.[23] The portfolio comprises Saver's Switch (for residential and small business customers), our interruptible tariffs (Electric Rate Savings), and our Short-Notice Rider customers (for medium and large C&I customers). Customers accounting for approximately 11 percent of medium and large C&I peak-coincident demand are enrolled in one of these offerings.

We believe that these existing programs will grow over the next few years. For example, we believe our Saver's Switch program will continue to grow to include those customers who are not interested in an interactive smart thermostat but are interested in participating in demand response for emergency purposes. Saver's Switch is a program in which customers can participate without having to take direct action for a control event – the Company directly controls these resources. We also intend to begin exploring two-way communication switches that allow for smart meter integration. Our Electric Rate Savings program, however, is expected to grow minimally over the next several years, in part due to likely adjustments to future requirements regarding MISO required testing and future winter controls. In Table 1, we have estimated an increase of 63 MW in existing programs based on our current load forecast provided to MISO.

3. *Expanded and New Traditional Demand Response Programs*

We estimate expanded and new program load utilizing the results of the 2019 Potential Study estimations. The expansion and addition of the traditional demand response programs identified as cost-effective results in a projected addition of 293 Gen. MW by 2023. Unlike the 2019 Potential Study, however, which front loads achievement in the beginning of the review period, we have estimated tiered growth from 2019 through 2023 to reflect likely customer adoption. This does not affect the forecasted megawatts of added demand response by 2023. Below, we discuss the programs we intend to expand and add.

[23] The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory, The Brattle Group, June 2019.

The largest growth of our demand response portfolio in the next five years will be in the expansion and transition to A/C Rewards for the majority of new customers. In 2017, we launched the A/C Rewards program, which allows customers to install a smart thermostat and sign up for demand response controls, allowing for flexible participation. Currently, we have more than 4,800 customers participating in A/C Rewards in Minnesota and the program was recently launched in Wisconsin. We are also seeking approval to expand into South Dakota.[24]

The program, as part of CIP, was recently filed with the Department for approval for 2020.[25] In this plan, the Company is expanding the program to include thermostat optimization which will maximize savings for customers for energy efficiency and provide additional benefit outside of demand response to entice customer interest. We are also anticipating the expansion of direct install channels, exploring the addition of further technologies (currently we partner with Honeywell and EcoBee), and continuing to increase our marketing opportunities, making sure to make the program and demand response visible to residential customers through advertising.

In addition, the Company is working with the Center for Energy and Environment to conduct a non-wires pilot that will estimate the savings potential of geotargeting our resources to defer the cost of distribution upgrades. The pilot, beginning in 2019, will make targeted investments to increase residential demand response (Saver's Switch and A/C Rewards) in specific geographic areas and test increased control in these areas. Final details of the pilot, in regards to demand response, are in final planning.

We have also begun to study smart thermostats in small commercial settings by offering customers an Ecobee subscription service that allows customers to manage multiple thermostats and buildings within the same portal. We hope to engage customers in managing their demand and increasing participation in demand response efforts in small business. This will be a one-year test through which we hope to identify the opportunity to request a full program in 2021. Unlike the other new products included in our five-year action plan, our estimates for adoption of the Small Business

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[24] *See* PETITION FOR 2018 DSM PROGRAM APPROVAL AND APPROVAL AND PROPOSED 2020 DSM COST ADJUSTMENT FACTOR, Docket No. EL19-019, (May 1, 2019).
[25] *See* Minnesota Conservation Improvement Program 2020 Extension Plan, Docket No. G,E002/CIP- 16-115, (July 1, 2019).

Thermostats program were not based on the 2019 Potential Study. Instead, we estimated these potential savings based on product development projections of savings.

The 2019 Potential Analysis also found that there was an untapped market for traditional demand response for mid-sized customers. We have submitted for approval, through CIP, a Peak Partner Rewards program to help grow this market.[26] The Peak Partner Rewards program will offer bill credits to customers who agree to reduce their electric loads when the electric grid experiences demand response periods. The program is primarily focused on achieving dispatchable demand response savings and will be marketed to mid-sized commercial customers.

The Company continues to review opportunities for new interruptible rates that can be offered in addition to our existing Electric Rate Savings program. A new interruptible rate product the Company is designing (but has yet to include in a petition to the Department or Commission) will offer an opt-in demand reduction rate to large C&I customers that either a) are not currently on peak-controlled rates or b) were previously enrolled and still have demand reduction potential. The new rate will offer bill discounts in exchange for committed demand reductions similar to Electric Rate Savings. Unlike Electric Rate Savings, however, this interruptible rate will offer customers more participation options so they are making realistic and reliable commitments to the Company that align with their business needs. The 2019 Potential Study identified over 100 MW of opportunity for such an interruptible rate meeting the cost criteria identified in the analysis.

The 2019 Potential Study also identified an opportunity for "demand bidding." This would involve the creation of a program that allows customers to bid demand reductions into the MISO energy market through the Company. As part of the study analysis, enrollment for various programs was estimated under a variety of pricing conditions for the population of potential participants (i.e., those customers who were not already participating in any existing program). The results of this analysis suggest that, if a demand bidding program were not available, the vast majority of customers who would otherwise participate in the demand bidding program would instead be likely to participate in the interruptible rate. We have determined that the demand

[26] *See* Minnesota Conservation Improvement Program 2020 Extension Plan, Docket No. G,E002/CIP-16-115, (July 1, 2019).

bidding opportunity (and potential cost) through MISO is limited at this time, and therefore included the megawatts of load reduction potential from the demand bidding category as part of our goals for a new interruptible rate.

4. *Non-Traditional Pilots and Programs*

As noted above, we believe there is benefit to piloting non-traditional demand response options if a cost-recovery mechanism for these pilots can be identified. Based on an assumption that we will be able to identify such a cost-recovery mechanism, we have included some non-traditional programs in our five-year action plan.
We have currently requested approval to add electric water heaters (utilizing enabling technologies) to participate in our Saver's Switch program.[27] This would allow customers with an existing electric water heater to participate in prescribed events. The benefit of this technology, however, is estimated at less than one megawatt per year of load availability – much smaller than the potential demand savings from grid-connected electric water heaters' thermal storage capabilities. As shown in Table 1, the Potential Study estimates potential savings of 13 Gen. MW of demand response for this technology; but unless an additional funding source is identified, this potential is unlikely to materialize. Nonetheless, because the 2019 Potential Study identified this technology as cost effective, we have included in our Preferred Plan.

The total cost-effective new demand response identified in the 2019 Potential Study plus Small Business Thermostats amounts to 309 Gen. MW for both traditional and non-traditional programs. In addition, as discussed above, we currently project 63 Gen. MW of additional demand response through natural growth to existing programs between 2019 and 2023. Combined with the new and expanded demand response programs discussed above, this totals 369 Gen. MW of demand response, or 22 Gen. MW less than required by the Commission's Order.

To address this gap, we have identified, and included in our action plan, an additional opportunity that we believe will be an important program in the future of demand response, even though the 2019 Potential Study did not identify it as cost-effective. Auto DR (energy management system control of lighting and HVAC to reduce and/or shift specific commercial loads) has potential to grow our demand response portfolio,

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[27] *See* Minnesota Conservation Improvement Program 2020 Extension Plan, Docket No. G,E002/CIP- 16-115, (July 1, 2019).

and has been effective in other areas of the country, like California. For purposes of the Resource Plan, and as shown in Table 1, we have conservatively estimated the potential benefit of this technology as half the technical potential shown in the 2019 Potential Study. The 22 Gen. MW of potential benefit we have identified—when combined with the other demand response additions—satisfies the Commission's requirement to acquire 400 MW of additional demand response. Like other non-traditional demand response opportunities, however, this tool is currently dependent on enabling technologies that are high in cost. We believe that a small pilot for Auto DR is an option that soon can be explored, and if enabling technology is put in place, we believe this program could achieve the savings shown in Table 1.

In Table 1, we provide a category for other non-traditional products currently in development. This category includes behavioral demand response and critical peak pricing, which would be enabled by smart meters. We are also exploring customer sited batteries, thermal energy storage, building controls and reverse demand response. All of these products and opportunities would require alternative filings and cost recovery mechanisms to pilot in Minnesota. In the meantime, we intend to pilot some of these technologies in other jurisdictions.

We note, that many of the new programs noted here could take several years to mature or develop in the market, specifically for products controlling or changing load. Some products could be difficult to understand, requiring significant incentives and education to induce customers to alter their energy usage. We anticipate that there will be periods in which peak load for existing demand response is lost as customers explore other options available to them. Therefore, although we believe the load forecasts in Table 1 are as accurate as possible at this time, actual customer load and participation may vary.

5. Battery Storage Alternative

Although we have a plan to add the 400 MW of demand response required by the Commission, we believe it is important to recognize that—because some of these resources may not be cost-effective—adding all of the demand response could come at a cost to customers. Moreover, as specific programs are developed and the Commission has the ability to weigh in on them, we believe challenges outlined in this appendix may result in a lower level of demand response than we anticipate in our action plan.

We, therefore, are exploring alternatives to demand response that would provide our customers and system with similar benefits but at a lower cost. One alternative that we believe is worth pursuing as an alternative is storage resources. Storage resources provide all of the same characteristics as demand response and likely provide greater controllability with fewer dispatch limitations. As a result, we view them as an essential resource in the future to balance high levels of renewables. While the economics of storage resource may not yet be at or below parity with a CT or some demand response options, we believe that delta is quickly closing, and it would be more beneficial to pursue some storage resources now rather than adding non-cost-effective demand response. Doing so will allow us to start growing these resources and learning about them before we need substantially more on our system.

To be clear, we are committed to adding incremental demand response. But, as an alternative to demand response programs that may not be cost-effective, we propose allowing incremental storage to meet some portion of the 400 MW requirement.

B. Ongoing Analysis

In addition to our plans for updating and providing new demand response products in the future, we continue to test new technologies and options for customers. One example of our product development efforts is our smart thermostat optimization efforts.

The Company ran a Smart Thermostat Optimization Pilot under the name MyHome during summer 2017, summer 2018, and winter 2018/19. The pilot tested the effectiveness of Tendril's Orchestrated Energy product to provide demand response and energy efficiency savings. Tendril's product optimizes participant's smart thermostats by evaluating the thermal properties of the home, occupancy patterns within the home, and customer preferences for both comfort and energy savings, amongst other data points. All of this data goes into Tendril's product, and the result is an optimized thermostat schedule for each participant that saves energy while also maintaining customer comfort. When demand response events are dispatched, Tendril's product shifts its focus to minimizing energy usage during the event windows. Again, this is achieved by evaluating each participant individually and optimizing a load-shifting strategy that reduces energy usage during the event window while also minimizing comfort impacts to participants. Applying Tendril's product to customers' smart thermostats resulted in additional savings on top of those achieved when customers upgrade to a smart thermostat. Specifically, demand response savings were consistent with what we have seen with our A/C Rewards program, and energy efficiency savings were also observed. We continue to evaluate this technology to determine whether to include it as a full program offering.

IV. ENERGY EFFICIENCY

We currently offer more than 40 energy efficiency programs, ranging from Home Energy Squad visits and reduced-price LED light bulbs at local hardware stores to our Process Efficiency program providing comprehensive whole-building energy efficiency analysis. We continually evaluate emerging technologies and program models, looking for new opportunities to expand our already extensive portfolio of energy efficiency options and educate customers on ways to conserve energy.

Below, we discuss the requirements related to energy efficiency arising out of our last IRP, the historical performance of the Company's Conservation Improvement Program (CIP), how the planning outlook was determined in the Preferred Plan, including a potential study conducted on behalf of the Department, the results of our modeling, and the impact of naturally occurring conservation, and a discussion of competitive bidding for customers exempt from CIP. Unlike demand response, we do not include a specific action plan for energy efficiency in this filing. Instead, we will present an energy efficiency action plan in our next CIP Triennial Plan filing.

A. Integrated Resource Planning Requirements for Energy Efficiency

The Commission's January 11, 2017, Order in Docket No. 15-21, at Order Point 11, 12, and 14.f states:

- An average annual energy savings level of 444 GWh for all planning years is approved; and
- Xcel shall investigate the potential for energy-efficiency competitive bidding process for customers that have opted out of the statewide Conservation Improvement Program (CIP) under Minn. Stat. §216B.241, subd 1a(b).
- In its next resource plan filing, Xcel shall . . . summarize its investigation and findings concerning the potential for an energy-efficiency competitive bidding process for customers that have opted out of CIP.

As discussed below, our Preferred Plan increases our projected energy efficiency savings in this planning period from 1.5 percent to 2.5 percent of Minnesota retail sales through a combination of both programmatic savings and naturally occurring energy savings.[28] Although this is an aggressive goal, we believe it is achievable. We further believe this can be achieved without providing an energy-efficiency competitive bidding process for opt-out customers.

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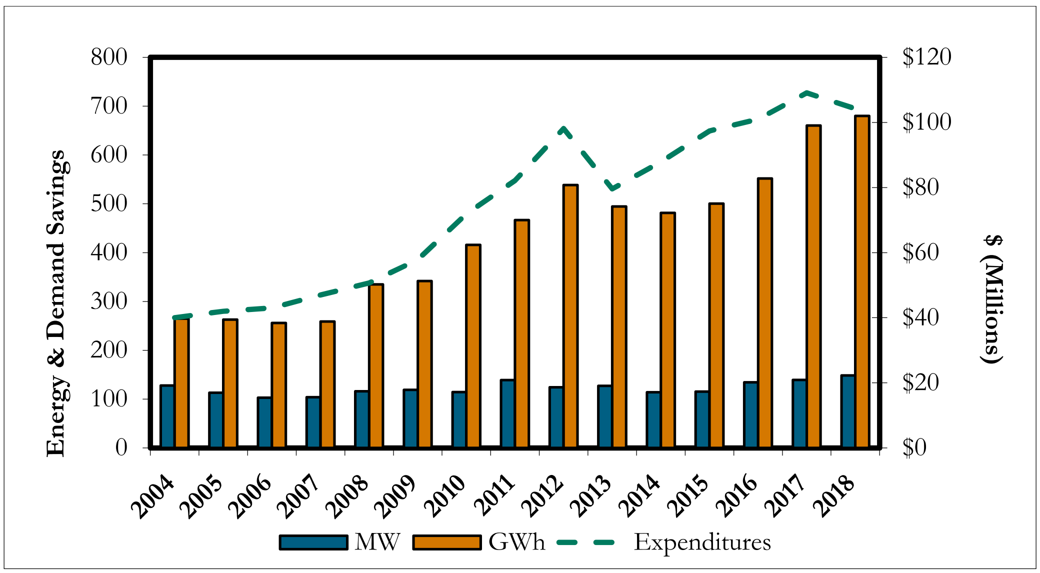
[28] ORDER APPROVING PLAN WITH MODIFICATIONS ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Docket No. E002/RP-15-21, (January 11, 2017) – required 444 GWh per year in the planning period which was 1.5 percent of retail sales.

B. Historical Performance of Programmatic Energy Efficiency

Xcel Energy has one of the longest-running and most successful DSM programs in the country. Between 1990 and 2018, the Company spent $1.5 billion (nominal) on Minnesota DSM efforts and saved nearly 9,700 GWh of energy and 3,600 MW of demand. Our efforts to continuously grow and modify our customer offerings prove worthwhile as we continue to meet and exceed the state's 1.5 percent of retail sales energy savings target for CIP. The figure below highlights our historic electric CIP savings achievements.

Figure 5: Historical Electric CIP Achievements 2004-2018



Our energy efficiency portfolio has a significant impact on carbon reduction. Technologies and improvements implemented as part of energy efficiency programs generally last for several years. Reductions in energy usage based on these programs, therefore, result in commensurate reductions in carbon emissions for the same period of time. For example, our year with the highest amount of energy savings achievement in CIP was 2018. The energy efficiency measures and projects implemented during 2018 alone are anticipated to save more than 2,440,000 short tons of carbon emissions over their entire lifetimes.[29]

[29] On average, the energy efficiency projects and measures installed through CIP in 2018 have a lifetime of 12.8 years. Source: 2018 CIP Status Report (Docket No. E,G002/CIP-16-115).

The time of day and year that efficiency savings take place also impacts the level of emissions avoided. Based on 2018 results, targeting energy efficiency impacts at hours when marginal generation has the most carbon-intensive emissions rates can result in carbon emissions reductions nearly 30 percent greater than savings that occur when the marginal generation avoided is an average mix of resources.

C. Energy Efficiency Planning Outlook

The Company's projections for energy efficiency savings of 2.5 percent of retail sales are based on a combination of two major types of energy efficiency: energy savings from CIP programs and naturally occurring energy savings. In this section, we discuss the Company's current projections for efficiency savings from CIP programs, and how we developed those projections. We also discuss how naturally-occurring conservation impacts our planning outlook.

1. Energy Efficiency Scenarios

We began the development of DSM scenarios with the Minnesota Statewide Potential Study analysis conducted on behalf of the Department. The scope of this study was designed by the Department and opened to third-party bidders who committed to capture the possible measures and customer segments that would increase adoption of energy efficiency across the state. The Company was just one of many utilities that participated in the study, providing information for inputs, reviewing drafts, and participating in a stakeholder advisory committee. The study was completed as a Conservation Applied Research and Development grant.[30]

The Company was heavily involved in the potential study to help provide information that would improve the applicability of potential study results to this Resource Plan. Engagement in the potential study included:

- DSM management representation on the Potential Study Advisory Committee members;

[30] The potential study was administered by Center for Energy and Environment, Optimal Energy and Seventhwave (now Slipstream). The full report can be downloaded here: https://www.mncee.org/MNCEE/media/PDFs/MN-Potential-Study_Final-Report_Publication-Date_2018-12-04.pdf

- Providing available data to the analysis team regarding savings, market research, and forecasts; and
- Reviewing draft documents including measure lists, technical assumptions, and technical, and achievable potential.

The Company further collaborated with CEE and the study vendor to produce estimates specific to NSP-Minnesota. This supplement to the study used the portion of statewide sales in the Xcel territory for the Residential and Business classes to develop achievable potential impacts and costs for the two scenarios for the Company's Minnesota territory to be used in this Resource Plan.

The study was used as the primary input for the Company's energy efficiency potential from 2020 through 2034 and included two scenarios: "Program Achievable" and "Maximum Achievable." The two scenarios in the study differ in terms of the percent of incremental cost covered by a utility rebate. The "Program Achievable" scenario estimates adoption of measures given utility rebates equal to 50 percent of the incremental costs. The "Maximum Achievable" scenario estimates adoption at rebates equal to 100 percent of the incremental costs, effectively removing any cost barrier to adoption. Doubling the rebate levels results in higher potential impacts, but also significantly increases the cost to achieve the incremental impacts. Table 2 below shows the impacts and utility program costs (including rebate) of each scenario in the Company's territory for the first and last year included in the potential study.

Table 2: Energy Efficiency Scenarios

	2020		**2029**	
	GWh	**Costs ($M)**	**GWh**	**Costs ($M)**
Program Achievable	621	$101	762	$162
Maximum Achievable	895	$262	1,096	$419

To model levels of Energy Efficiency most accurately as a resource in the Resource Plan, the impacts for each scenario were estimated at the hourly level and expanded over the lifetime of the measures installed. The two scenarios from the study provided achievable estimates each year for various end uses from both residential and business segments.

These end uses were bucketed into the following nine "shape" groups:

- Business Cooling: End-uses that cool occupied non-residential spaces. Highly correlated to weather with highest use during hot summer weekdays.

- Business Custom: Process and lighting end-uses at non-residential sites. Correlated to operating hours at a mix of types of businesses.
- Business Compressed Air: Leakage savings from end-uses that rely on compressed air. Generally flat hourly savings.
- Energy Management Systems: Operation savings from end-uses on an energy management system to reduces load when end-uses are not in use. Generally off-peak savings.
- Flat: End-uses that have constant hourly load across a year.
- Residential Cooling: End-uses that cool occupied residential spaces. Highly correlated to weather with highest use during hot summer evenings.
- Residential Lighting: End-uses that light occupied residential spaces. Correlated to non-daylight hours and residential occupancy patterns.
- Refrigeration: End-uses providing refrigeration in both residential and non-residential spaces. Correlated to weather and hours that the refrigeration cases are opened.
- Residential Water Heating: End-uses providing hot water to residential spaces. Correlated to residential usage of hot water.

The energy savings impacts for each of these "shape" groups were applied to the hourly load shapes and lifetime assumptions of these groups as used and assumed in the Company's current 2017-2019 CIP Triennial Plan. The table below shows the lifetime assumptions for each of the shape groups and the fraction of total energy savings each of the nine groups accounts for in the various forecasts.

Table 3: Percent of Portfolio Energy

		Program Achievable		Maximum Achievable	
Shape	**Lifetime**	**2020**	**2029**	**2020**	**2029**
Business Cooling	18	14.3%	18.5%	14.0%	17.7%
Business Custom	16	39.4%	46.3%	41.6%	48.4%
Business Compressed Air	17	1.5%	1.9%	1.6%	2.0%
Energy Management Systems	17	6.1%	2.8%	5.6%	2.4%
Flat	12	7.5%	13.9%	7.2%	13.3%
Residential Cooling	9	0.5%	1.3%	0.6%	1.6%
Residential Lighting	5	1.9%	0.6%	1.8%	0.5%
Refrigeration	9	26.8%	8.8%	25.8%	8.8%
Residential Water Heating	8	1.9%	5.8%	1.8%	5.4%

In addition to the two scenarios included in the study, the Company developed an "Optimized Scenario," which included a higher level of incentives for technologies that consistently save energy during on-peak hours, or hours that have the highest costs to serve. It is expected that these measures will be the most cost-effective. Specifically, the measures included in the "Optimized Scenario" are those in the Business Cooling, Residential Cooling and Residential Refrigeration shapes. The "Optimized Scenario" includes the costs and impacts of these three shape groups at the Maximum Achievable incentive level, with all of the other shape groups at the Program Achievable incentive level.

To model investments in energy efficiency to include in the Resource Plan, the three scenarios (Program Achievable, Optimized Scenario and Maximum Achievable) were expanded to cover program achievement over the 15-year plan period (2020-2034). The expected achievements and costs for 2029 were used to populate all years 2030-2034. With lifetimes extending up to 17 years, the lifetime impacts of these achievements extended from 2020 through 2050.

2. *Modeling Results*

To determine the most cost-effective level of future energy efficiency achievement, the following steps were taken:

- A revised load forecast was produced that removed the effect of all energy efficiency achievement over the 2020-2034 program years.
- The costs and lifetime impacts of each of the scenarios were modeled as a supply-side resource.

- The resulting total system costs were calculated assuming achievement of each of the three scenarios, expressed as both Present-Value of Revenue Requirements (PVRR) and Present-Value of Societal Costs (PVSC).
- Total system costs were compared to identify the most cost-effective level of energy efficiency.

We modeled energy efficiency as a resource in past resource plans based on utility program costs, similar to the Utility Cost Test used in DSM cost-benefit estimation performed in CIP Triennial Plans. When modeling energy efficiency as a resource, the magnitude of rebate spending should be considered. The scenario that provides the greatest benefits, when including the rebate spending, should be the Preferred Plan for energy efficiency.

The table below shows the PVRR of the three scenarios and the PVRR savings against the base case that removes the effect of all energy efficiency achievement:

**Table 4: Present-Value of Revenue Requirements (PVRR)
Energy Efficiency Scenarios (in Millions)**

	PVRR	Delta PVRR
No Future Energy Efficiency	$39,985	-
Program Achievable	$37,656	($2,329)
Optimal Scenario	$37,572	($2,414)
Maximum Achievable	$38,432	($1,553)

This data shows that the Optimal Scenario produces the greatest cost savings, with over $2.4 billion in savings for the 2020-2034 program years. The societal cost of emissions was also considered in modeling. The table below shows the PVSC of the three scenarios and the PVSC savings against the base case that removes the effect of all energy efficiency achievement:

**Table 5: Present-Value of Societal Costs (PVSC)
Energy Efficiency Scenarios (in Millions)**

	PVSC	Delta PVSC
No Future Energy Efficiency	$49,071	-
Program Achievable	$46,087	($2,984)
Optimal Scenario	$45,989	($3,082)
Maximum Achievable	$46,609	($2,462)

This metric also shows that the Optimal Scenario produces the greatest cost savings, with nearly $3.1 billion in savings for the 2020-2034 program years.

Based on these results, the Company included the Optimal Scenario in the Preferred Plan proposed in this filing.

3. *Naturally Occurring Energy Conservation*

Our Energy Efficiency scenarios also include conservation measures defined as naturally occurring, or energy savings achieved through implementation of high-efficiency equipment outside of or as a supplement to utility CIP programs. The drivers for naturally-occurring energy efficiency include: adoption of efficient technologies as industry standards, building code changes, customer preference for green products, and competition among manufacturers to differentiate product offerings. These factors lead to more naturally occurring energy efficiency in the market outside of or in addition to utility products and programs.

The energy savings resulting from naturally occurring energy efficiency includes customers who take action without participating in energy efficiency programs and instances of equipment that currently may be influenced by energy efficiency programs, but in the future would not be part of a energy efficiency program because an efficient technology has become common practice (also known as market transformation). Market transformation is driven by increasingly proactive manufacturers, improvements in building practices, and energy industry allies building upon our history of helping customers conserve energy.

Although the impact of the Energy Efficiency scenarios grow over time, as shown in Table 6, the utility share of savings from future energy efficiency may decline if customers achieve increased amounts of energy efficiency outside of utility programs.

The level of energy efficiency that is modeled in this Resource Plan is intended to represent the true effect of efficiency programs on sales and what is counted toward State savings targets. The Minnesota Statewide Potential Study does not take into account code and standard changes that are not already published. Rather than trying to complicate the forecasting process, the Company believes that it is appropriate to estimate the growing impact of naturally-occurring energy efficiency in the DSM goals. The effect in immediate years is small because standards for those years are well-known, but the end of the planning period will likely see an increasing amount of energy savings occurring outside of DSM programs. As a result, the achievements claimed by the utilities represent only a portion of the energy savings customers realize. For example, the Company recently discontinued the Computer Efficiency program because it had successfully transformed the market for personal computer (PC) power supplies. Even though rebates will no longer be offered and savings will not be claimed by the Company, customers will still consume significantly less energy sooner than would have occurred otherwise.

D. Energy Efficiency Bidding

In its January 11, 2017, Order, the Commission required the Company to investigate the potential for energy-efficiency competitive bidding process for customers that have opted out of CIP. We have long-standing relationships with our large Commercial and Industrial (C&I) customers. Only a handful of Xcel Energy customers have applied and qualified for exemption from the ongoing expenses of our electric CIP portfolio. The Company has investigated the process for exempt customers to bid in energy efficiency to the Company and determined there is no need for such a process at this time. This decision is based on the small number of exempt customers, the statutory requirement to continue energy efficiency analysis at these sites without the benefit of utility funds, and the nature of this customer group as described below.
CIP exceptions are defined by Minnesota Statute §216B.241, Sub. 1a. which in part states:

> The owner of a large customer facility may petition the commissioner to except both electric and gas utilities serving the large customer facility from the investment and expenditure requirements…***[of CIP]***…the filing must include a discussion of the competitive or economic pressures facing the owner of the facility and the efforts taken by the owner to identify, evaluate, and ***implement energy conservation and efficiency improvements***… (emphasis added)

Under this statute, customers seeking an exemption are required to file with the Department and must prove that they are implementing energy conservation and efficiency improvements. They also must show there is no need for additional incentives to manage, complete, and address energy efficiency measures. Exempt customers must provide a filing every five years to the Department explaining measures that they are already taking to be efficient. Given the small number of exempt customers in the Company's territory and these statutory efficiency requirements, in investigating a potential bidding process for customers who have opted out of CIP,[31] we determined that such a process would not facilitate meaningful efficiency improvements over the status quo.

These exempt customers are motivated to continue ongoing process evaluations and energy efficiency analyses. They are naturally incentivized to pursue efficiency improvements to continue to keep their product costs as low as possible, including any and all economically viable improvements related to energy consumption. We continue to work closely with these customers, interacting with them through our account representatives to serve their current and future energy needs.

We believe that the impacts of future energy savings for these exempt customers are captured in the load forecast. With the statutory requirement to prove implementation of energy conservation and efficiency improvements, it is reasonable to assume the same rate of implementing such improvements will occur in the future as it has historically for these customers. Since the growing rate of historical energy savings from these customers is reflected in actual sales data (in the form of reduced sales), we have determined that future energy savings (reduced sales) of future energy conservation and efficiency improvements are embedded into the sales forecast at the rate by which they occurred in the past.

Given the amount of load involved in our exempt customer base, as well as the reassurance of the Department's review and acceptance of these exemptions, including verification of ongoing energy efficiency improvements, we believe that a specific bidding process for these customers is not warranted at this time.

[31] ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, (January 11, 2017), Order Point 14 (f).

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

PREPARED FOR

Xcel Energy

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June 2019

THE Brattle GROUP

Notice

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

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Executive Summary

Highlights:

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

Background

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

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

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

"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 and refinements to program design. 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 a redesigned 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.

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

[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.

voluntary replacements of expiring conventional electric water heaters, and overall growth in NSP's customer base. By 2030, we estimate that NSP's current portfolio plus the incremental cost-effective DR would amount to 468 MW. New, emerging DR programs account for 33% of the incremental potential. Achieving this potential would require not only growth in existing programs, but the design and implementation of several new DR program as well.

High Sensitivity Case

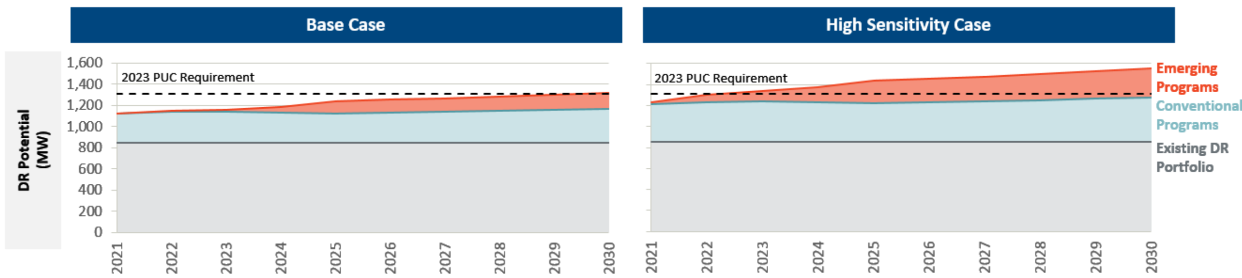
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the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

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

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

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

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



2030 Avoided Cost ($M/yr)

Base Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$1.7	$15.5	$0.9	$0.0	$0.0	$18.1
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$7.4	$22.9	$1.3	$0.0	$1.2	$32.8

High Sensitivity Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$3.1	$26.8	$1.1	$0.0	$0.0	$31.0
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$22.7	$46.3	$1.9	$0.7	$4.6	$76.2

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

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

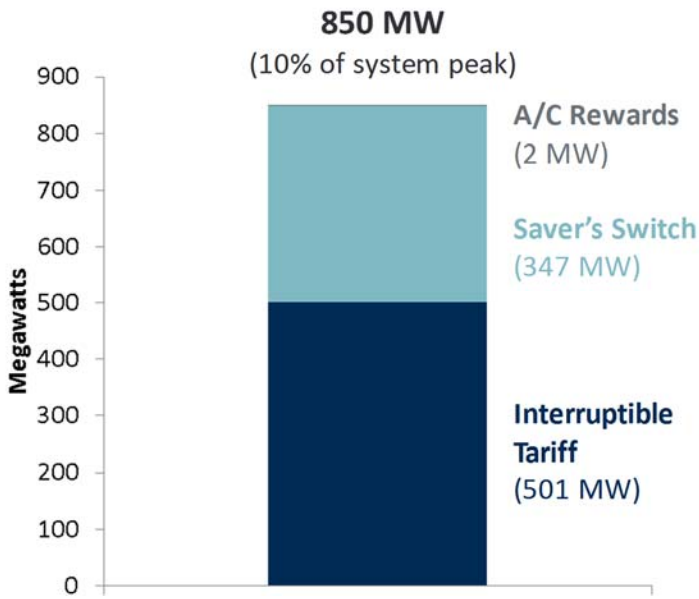
The capability of NSP's existing DR portfolio is substantial. It is the eighth largest portfolio among all US investor-owned utilities when DR capability is expressed as a percentage of peak demand. The portfolio is the largest in MISO in terms of total megawatt capability, and second when expressed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

[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.

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.

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.

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. Existing DR participants are excluded from the estimates of incremental potential.

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

II. Methodology

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

Conventional DR Programs

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

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

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

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

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

Non-conventional DR Programs

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

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

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

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

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

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

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

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

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

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

DR Benefits

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

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

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

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

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

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

- **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.

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.

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

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.

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.

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."

The Load*Flex* Model

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

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

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

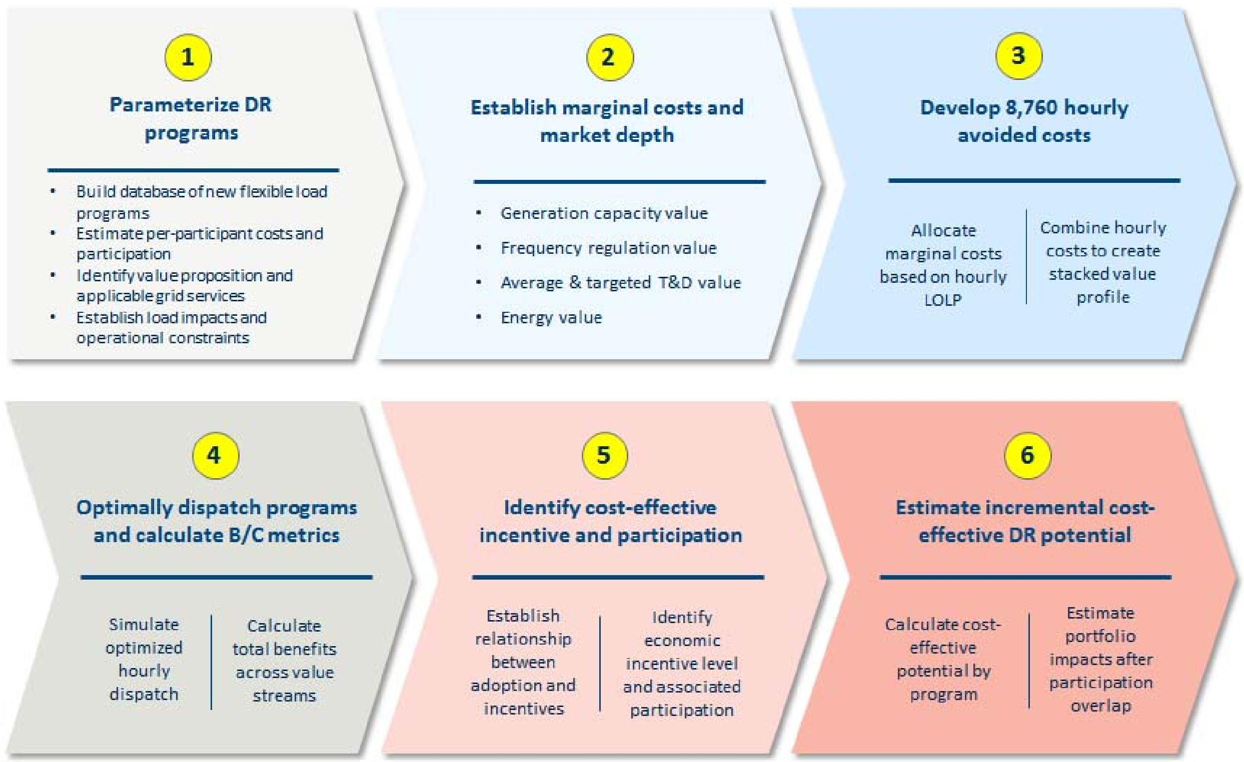
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes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

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

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

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

Figure 3: The Load*Flex* Modeling Framework



Modeling Scenarios

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

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

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

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

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

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

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

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

Data

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

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

Figure 4: Data Availability by DR Program Type

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

Notes:

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

◑ Signficant program experience in other jurisdictions

◔ Some pilot or demonstration project experience in other jurisdictions

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

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

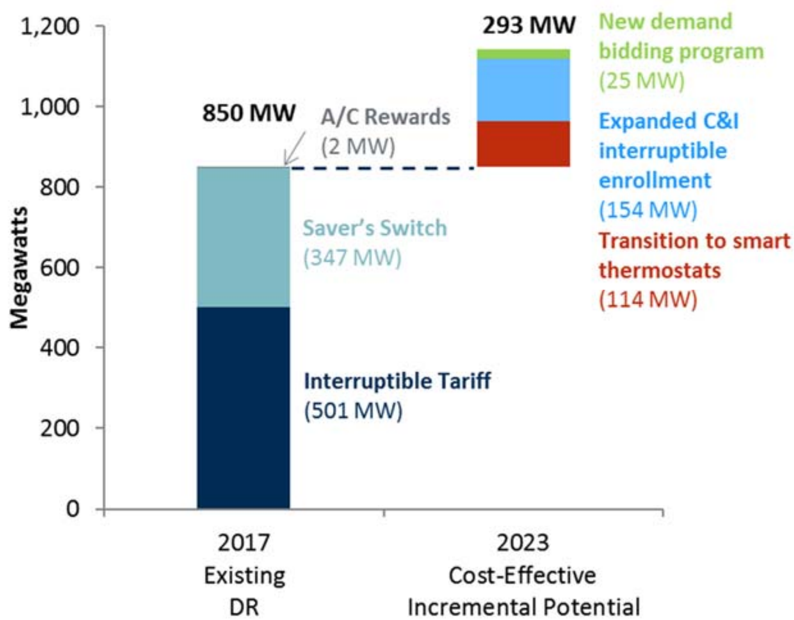
III. Conventional DR Potential in 2023

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

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

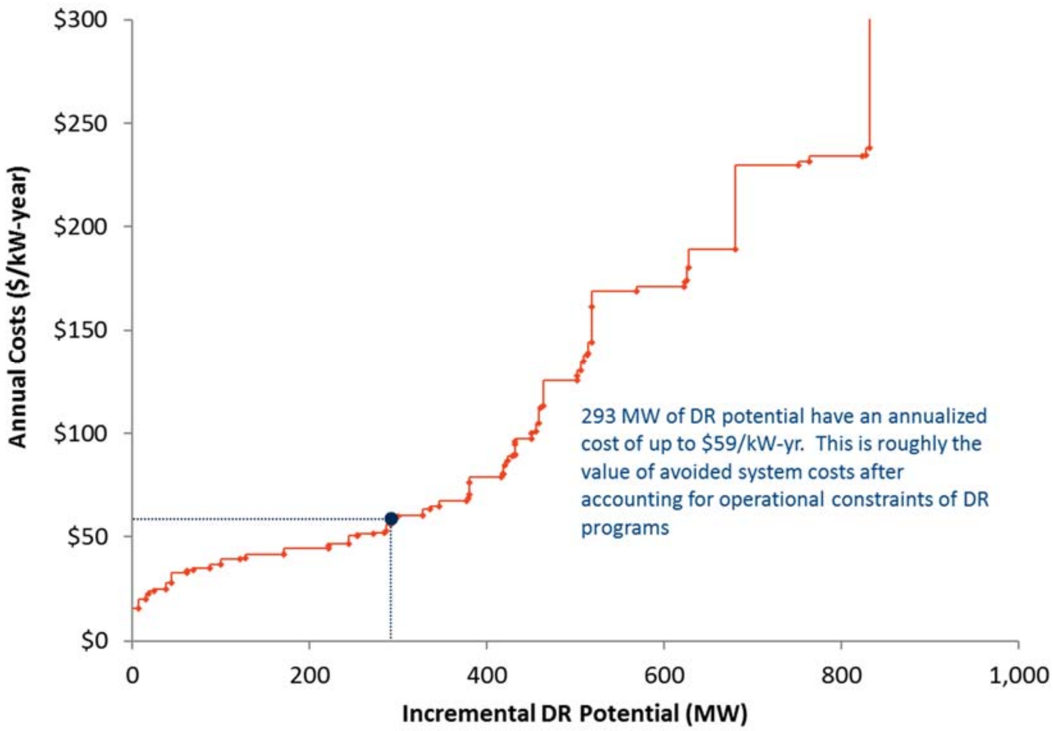
[10] NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

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



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

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



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

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

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

Table 3: NSP's 2023 DR Procurement Requirement

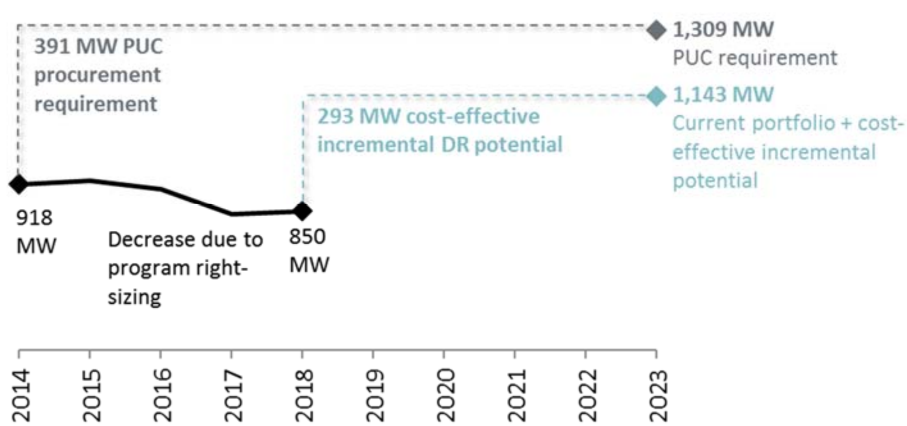
	Requirement (MW)	Notes
Meter level	361.7	Premise-level
Generator level	390.7	Grossed up for 8% line losses
Capacity equivalent	400.0	Grossed up for line losses and reserve requirement

Source: Calculations provided by NSP.

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

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

Figure 7: NSP DR Capability (Conventional Portfolio)



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

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

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

IV. Expanded DR Potential in 2023

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

Base Case

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

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

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

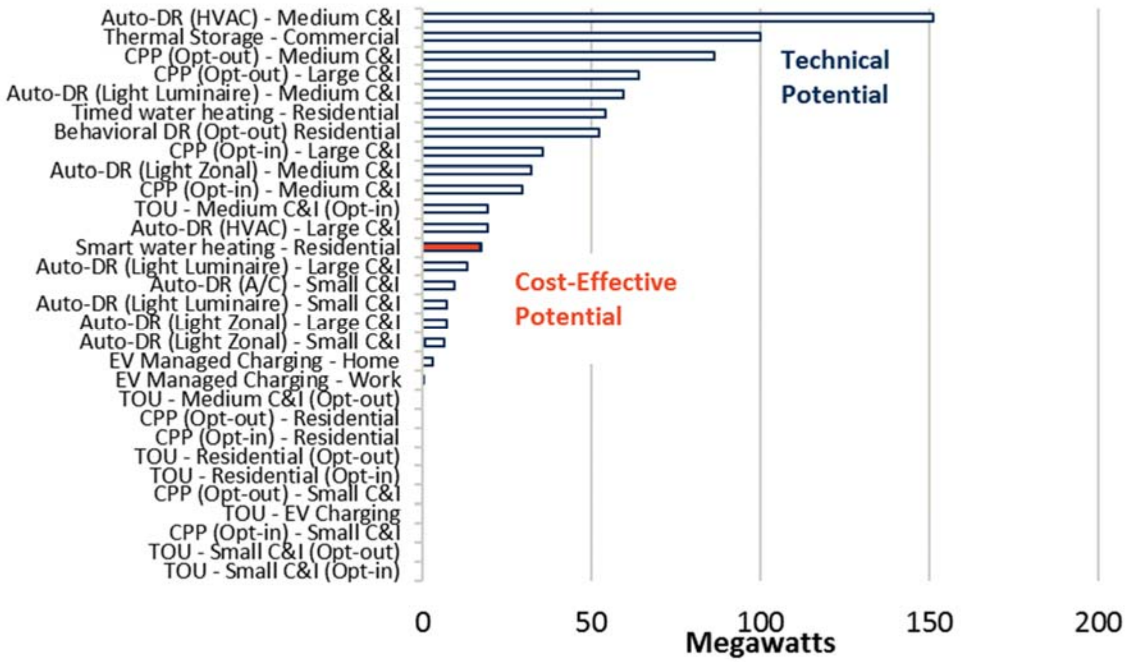
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

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

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

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

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

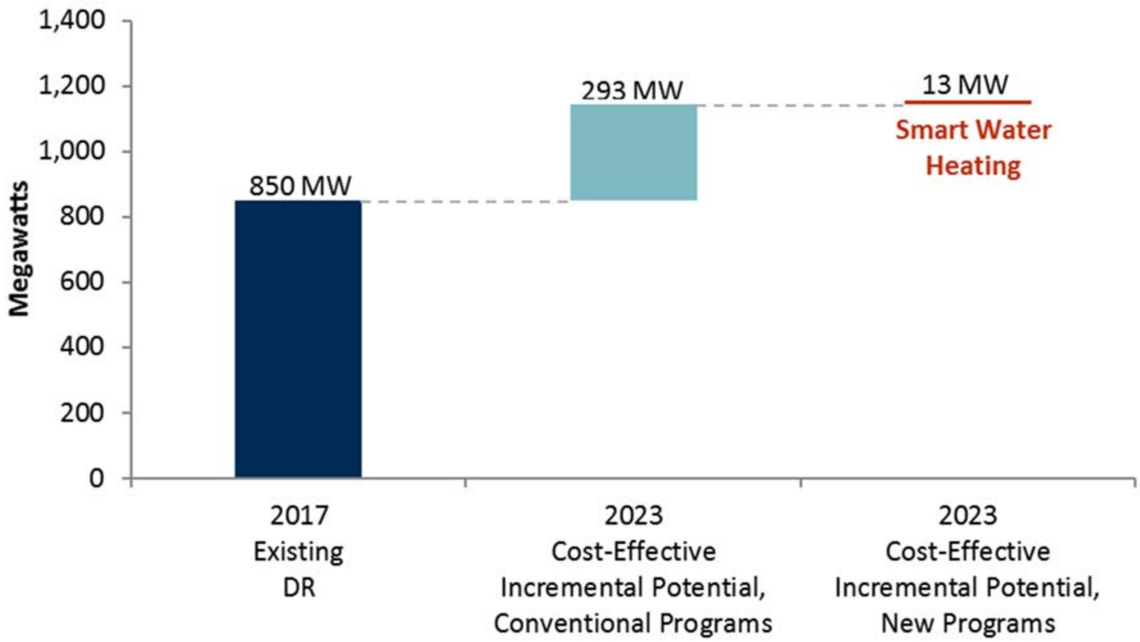


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

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

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

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



Near-term Limitations on DR Value

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

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

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

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

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

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

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

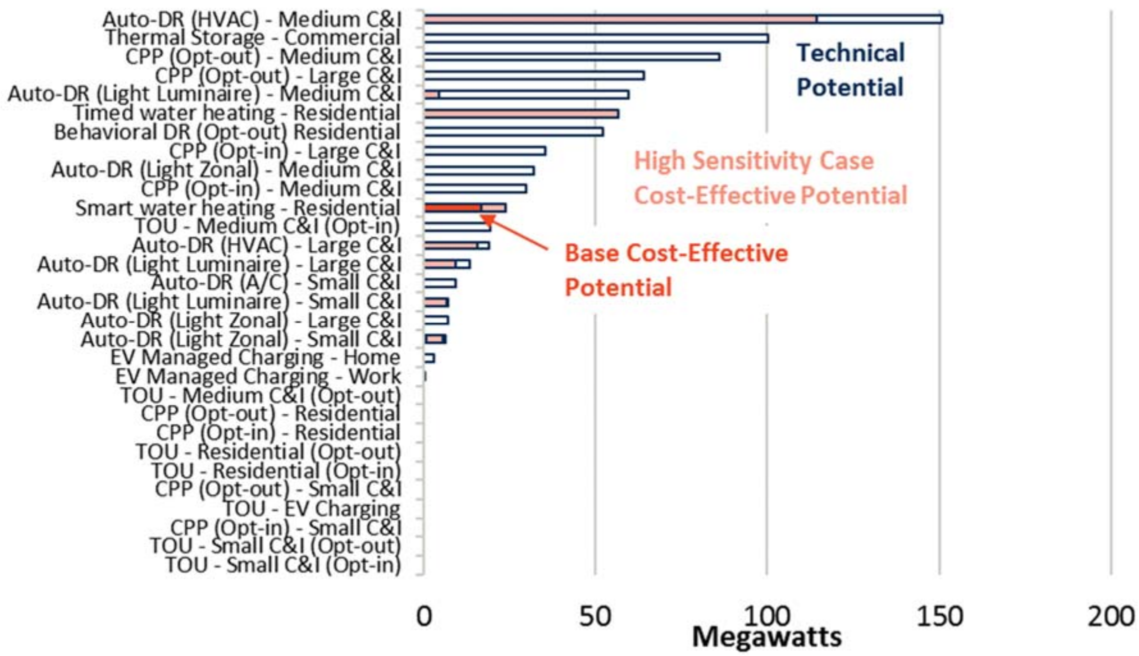
High Sensitivity Case

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

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

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

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



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

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

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

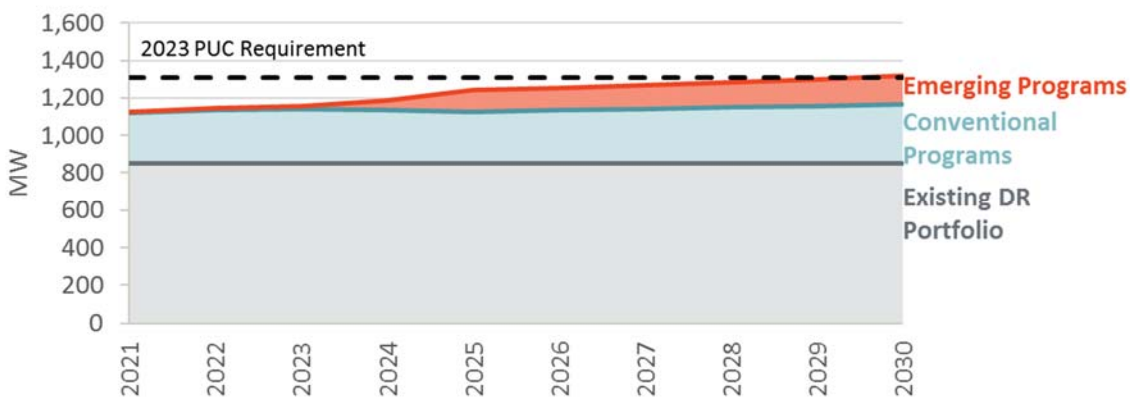
V. Expanded DR Potential in 2030

Base Case

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

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

Figure 11: Cost-Effective DR Potential, Base Case



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

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

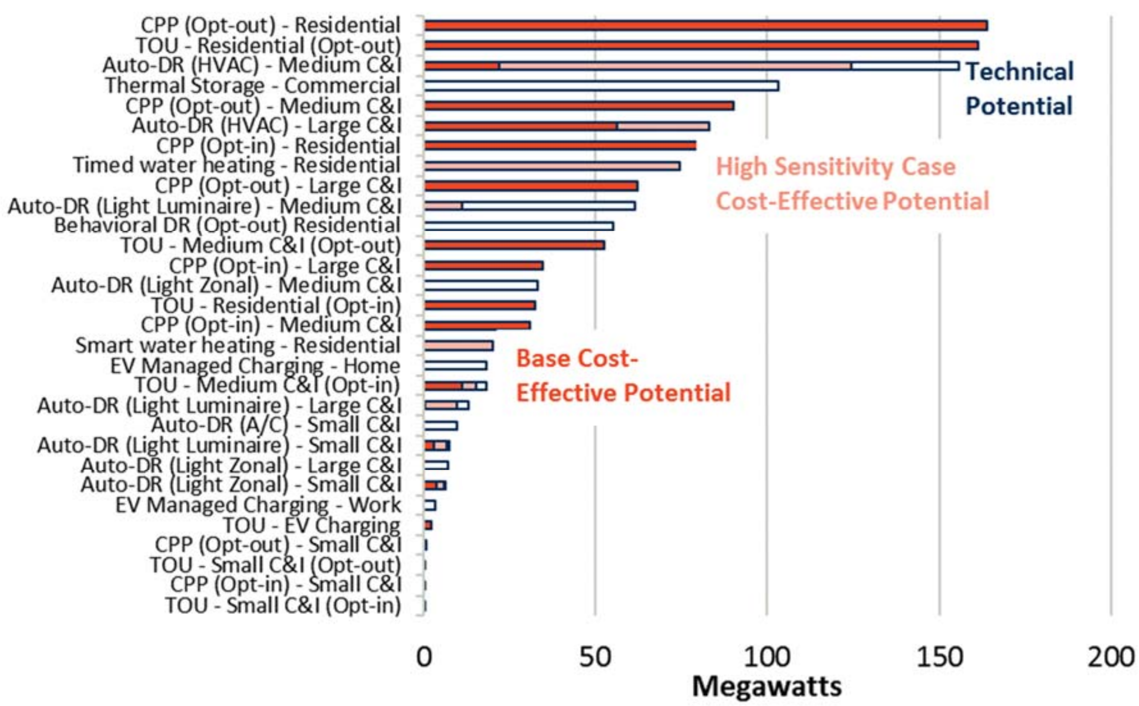
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

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.

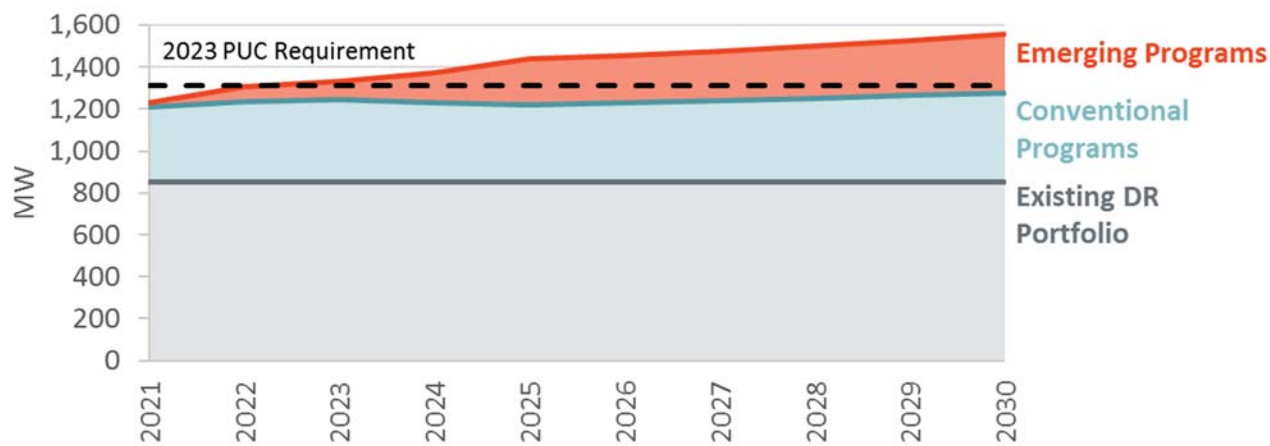
Figure 12: New DR Program Potential in 2030



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)

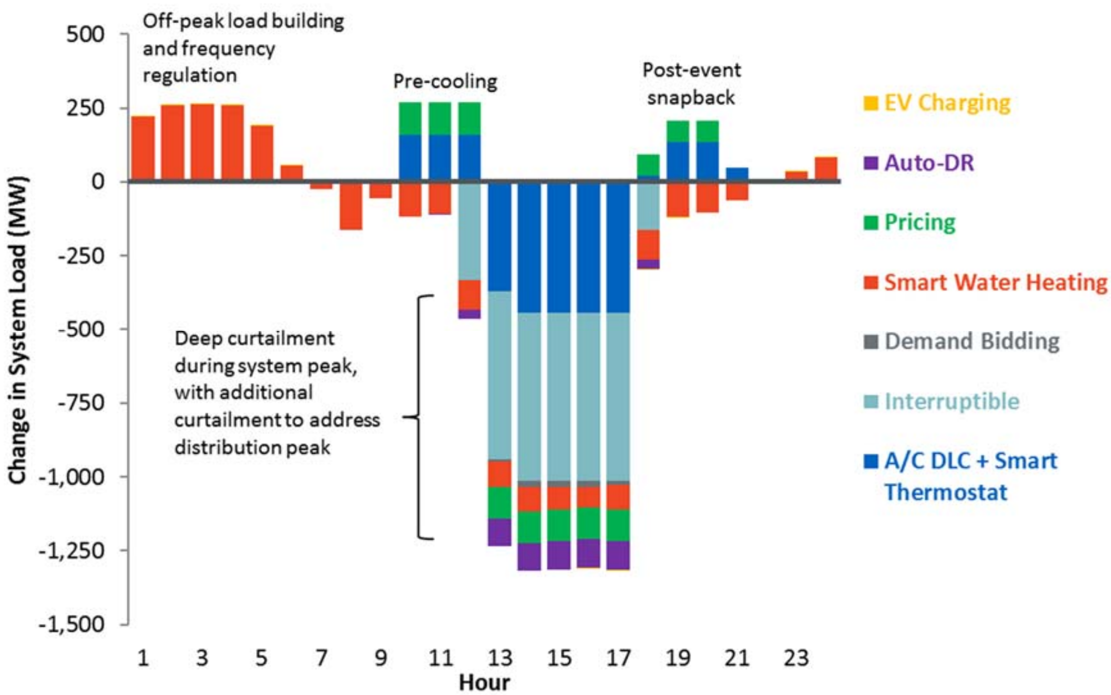
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

Notes: Benefits shown in 2023 dollars. Estimates include benefits from NSP's existing 850 MW portfolio.

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)



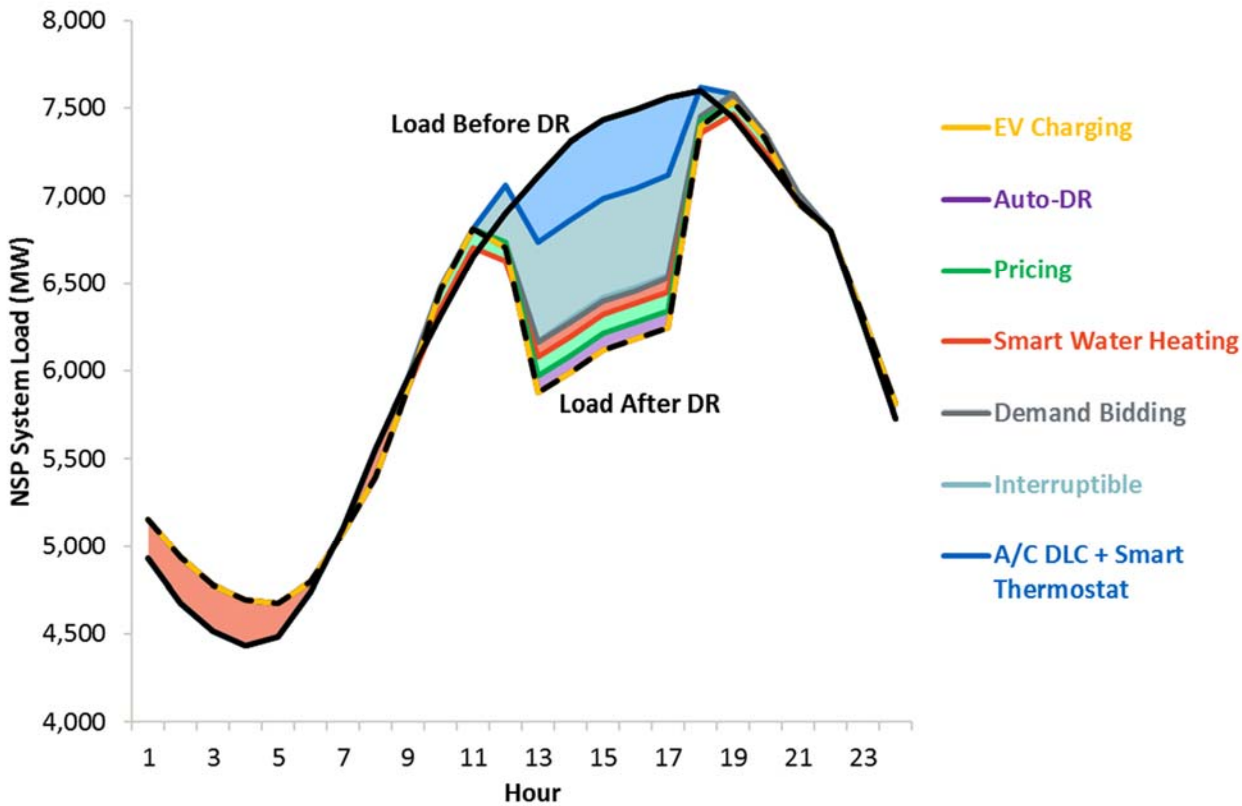
Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

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 a redesigned 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 modernized Medium C&I interruptible program present the largest incremental opportunity and the least amount of uncertainty/risk.

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

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

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

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

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

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Appendix A: Load*Flex* Modeling Methodology and Assumptions

The Load*Flex* Model

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

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

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

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

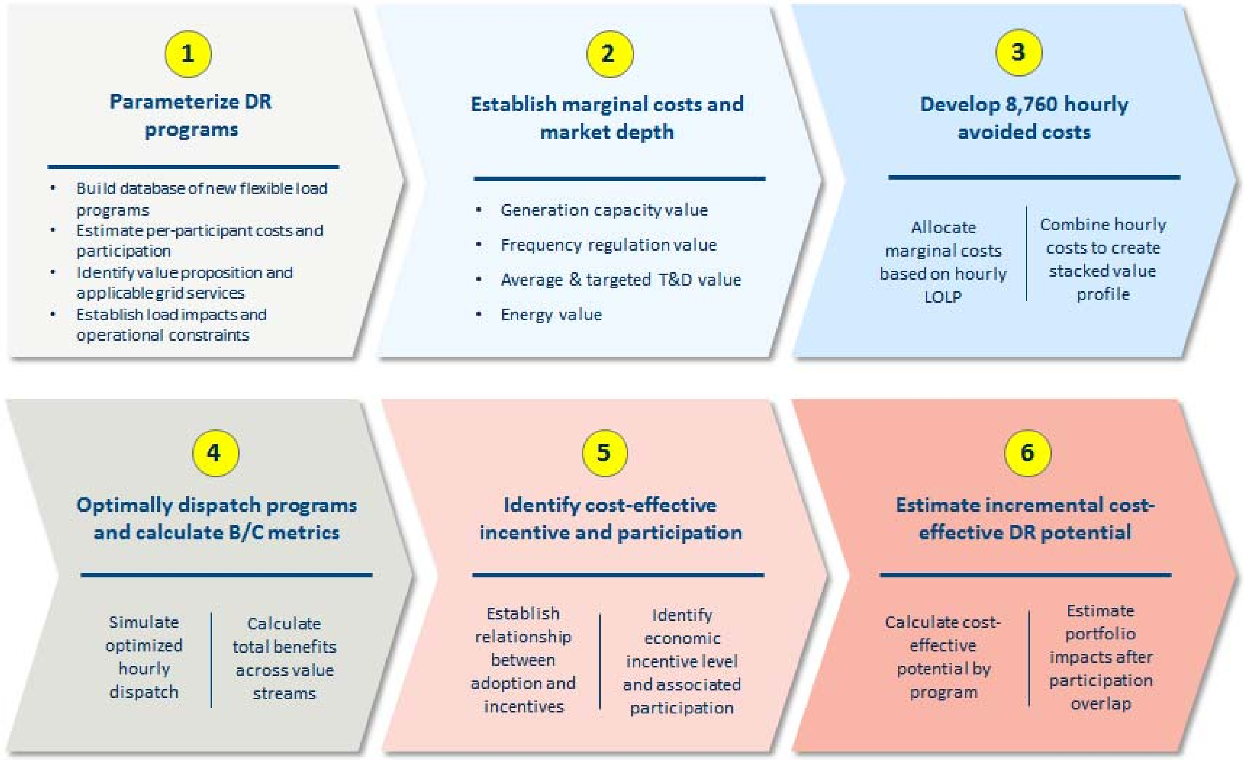
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes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

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

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

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

Figure 16: The Load*Flex* Modeling Framework



Step 1: Parameterize the DR programs

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

Program Performance Characteristics

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

Load impact profiles

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

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

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

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

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

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

[18] Daniel J. Olsen, Nance Matson, Michael D. Sohn, Cody Rose, Junqiao Dudley, Sasank Goli, and Sila Kiliccote (Lawrence Berkeley National Laboratory), 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.

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

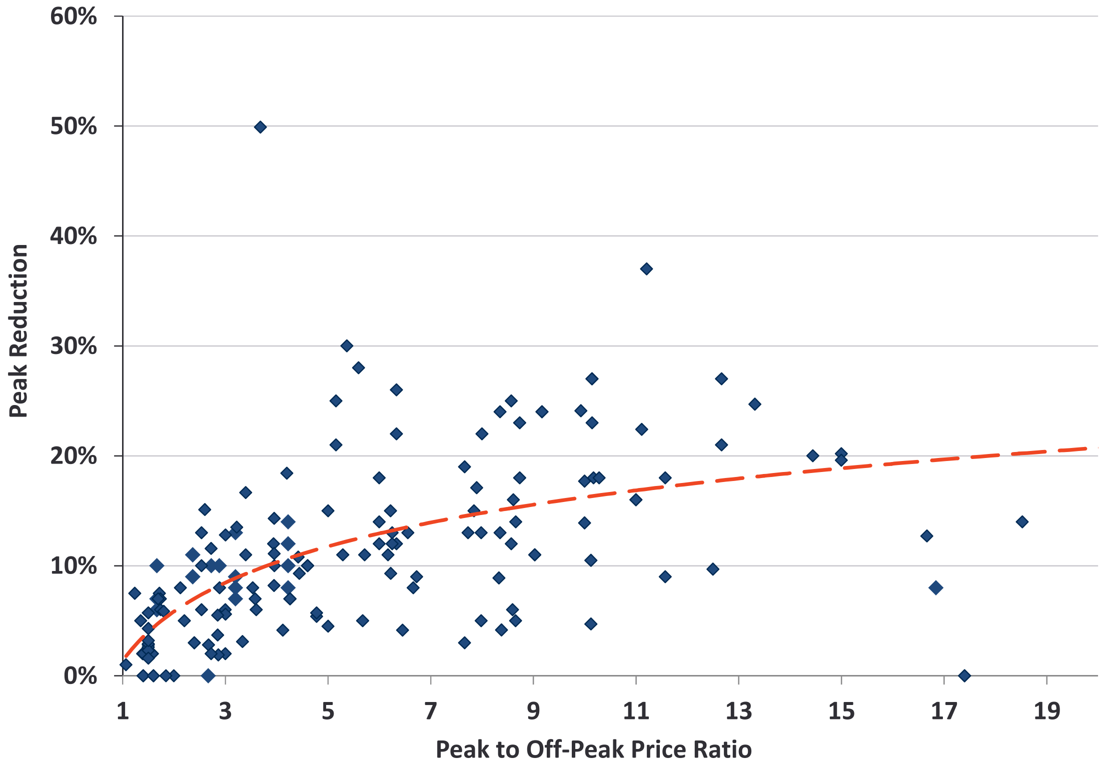
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

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

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

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

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



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

Daily relationship between load reduction and load increase

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

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

Tariff-related operational constraints

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

Ancillary services availability

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

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

Table 6: DR Program Performance Characteristics

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

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

Program Cost Characteristics

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

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

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

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

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

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

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

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

Table 7: 2023 Base Case Program Cost Assumptions

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

Notes:

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

Table 8: 2030 High Sensitivity Case Program Cost Assumptions

Segment	Program	One-Time Costs Fixed Cost ($)	Variable Equipment Cost ($/participant)	Other Initial Costs ($/participant)	Recurring Costs Fixed Admin & Other ($/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 move electricity to where it is needed during peak times while maintaining a sufficient level of

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.

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:

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.

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

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

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

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

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

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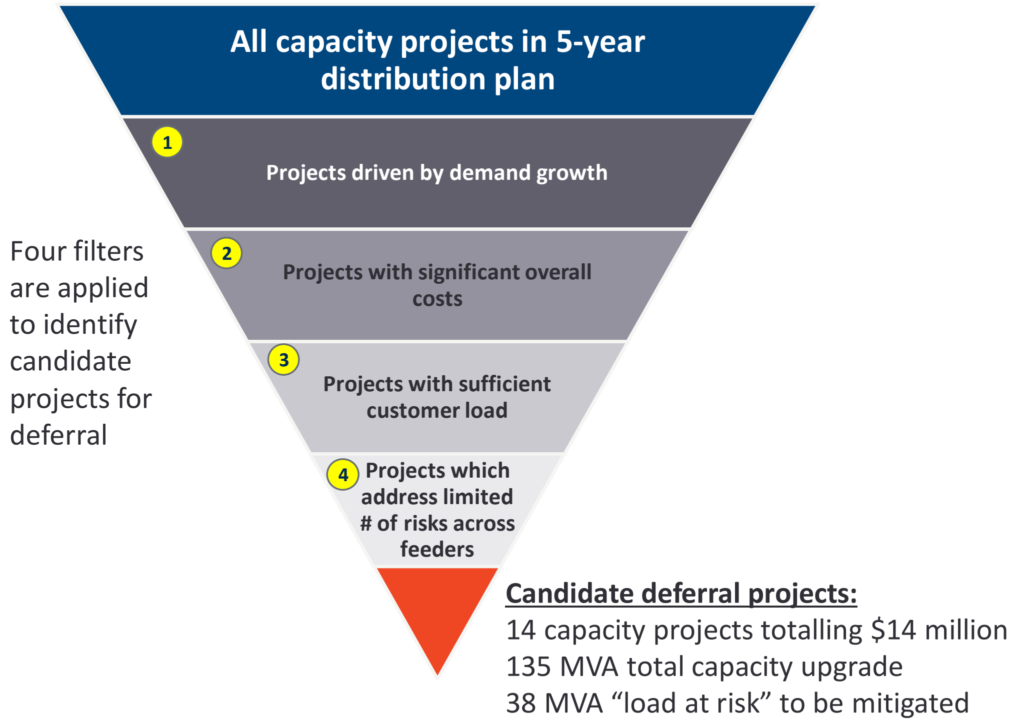
30 For simplicity, we assumed 1 MVA = 1 MW.

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

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



Avoided energy costs

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

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

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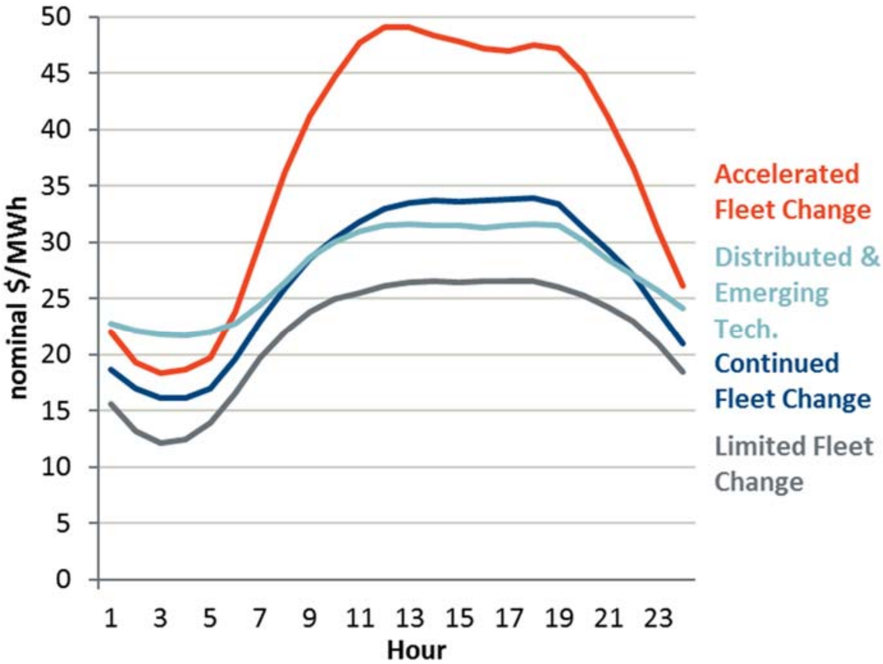
32 Energy savings refer to reduced fuel and O&M costs. In this study, we do not model the impact that DR would have on MISO wholesale energy prices. This is sometimes referred to as the demand response induced price effect (DRIPE). It represents a benefit to consumers and an offsetting cost to producers, 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.

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).

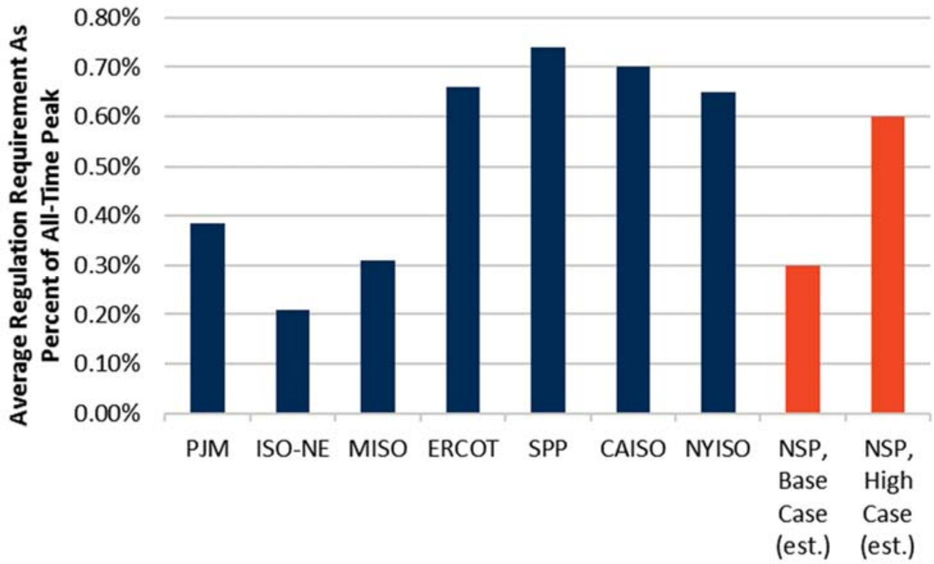
Ancillary services

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

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

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

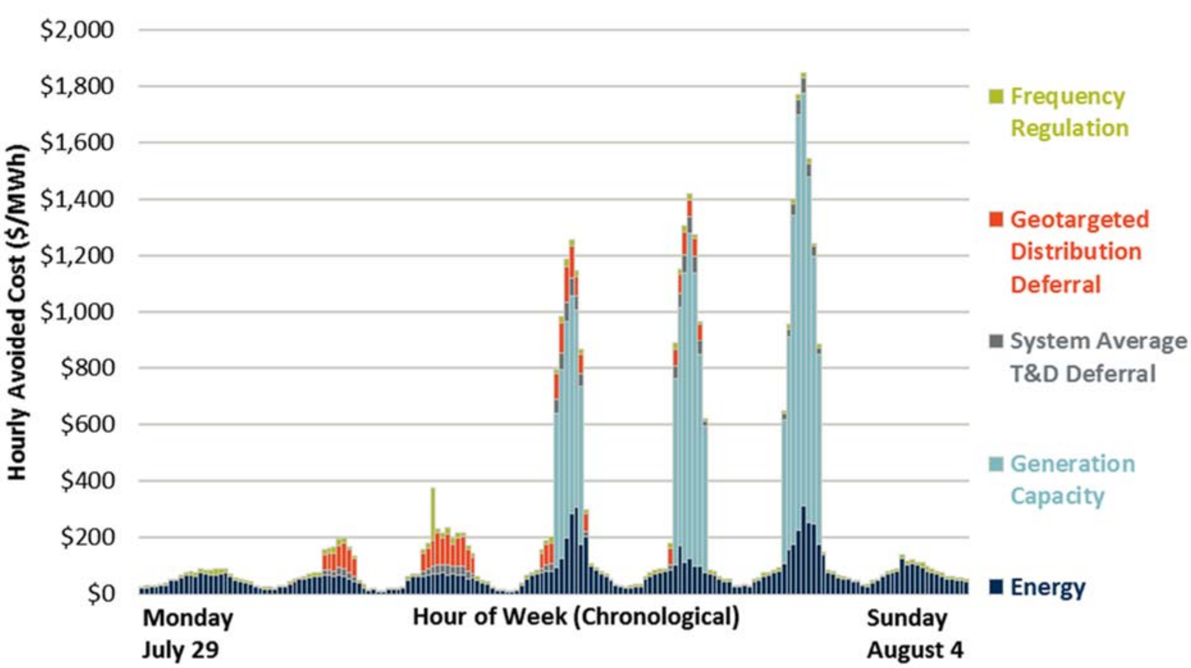
35 Capacity value was allocated proportional to MISO gross load because NSP is required to use its MISO-coincident peak for resource adequacy planning decisions.

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.

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



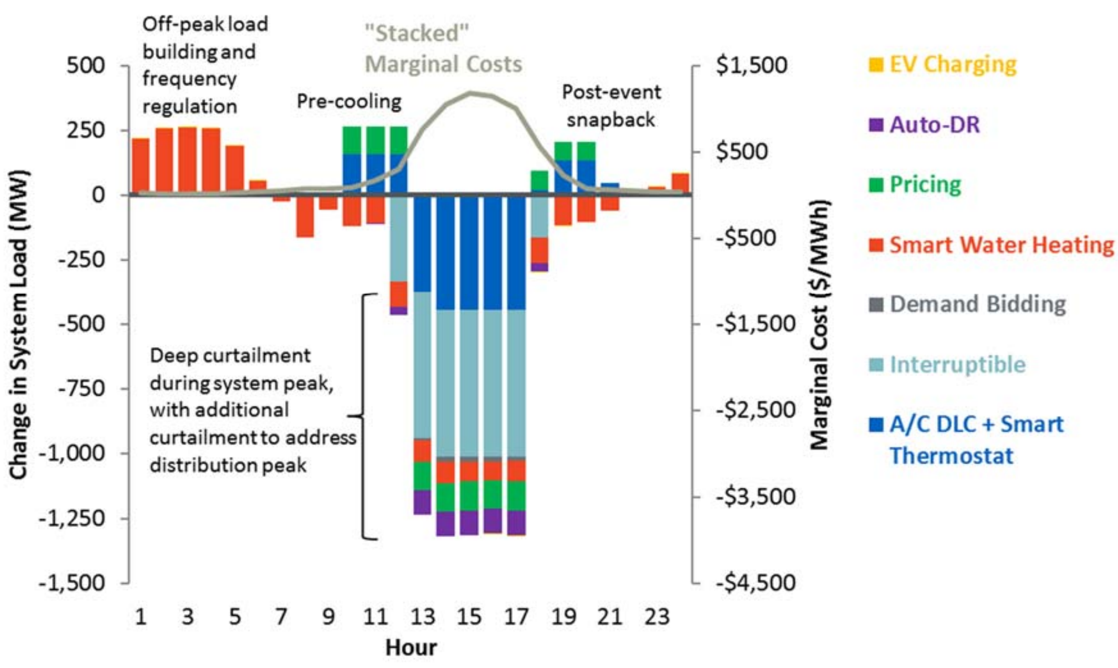
Notes: Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

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

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

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.

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.

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

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%

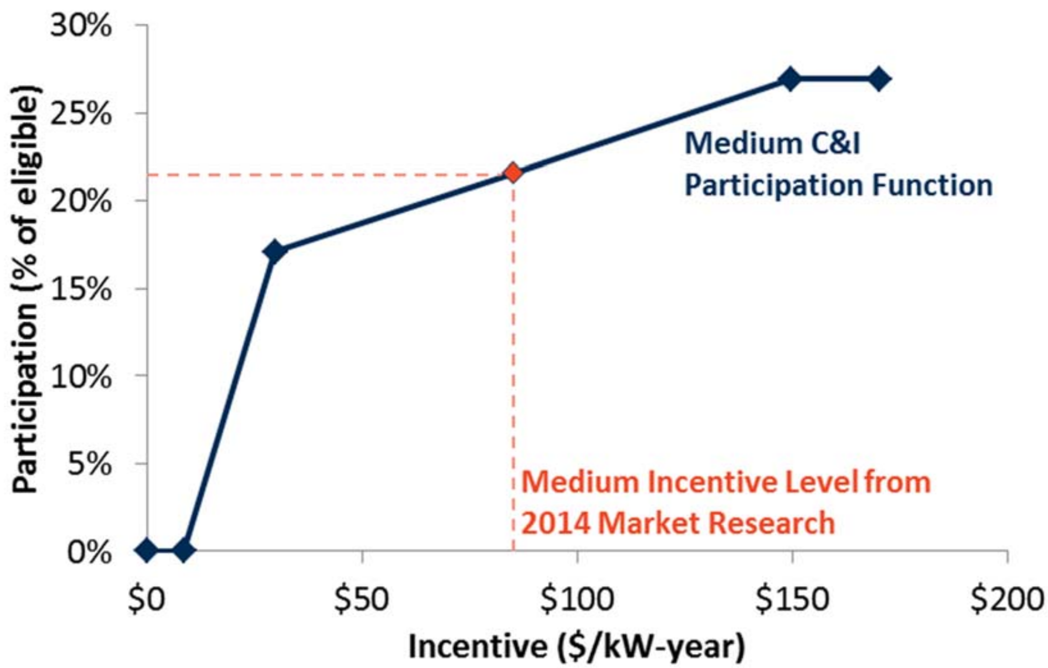
Notes:
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

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.

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

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

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

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

Appendix B: NSP's Proposed Portfolio

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

Table 13: NSP's Draft Portfolio of DR Programs

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

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

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

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

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

Appendix C: Base Case with Alternative Capacity Costs

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

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

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

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

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

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

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

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

Appendix D: Annual Results Summary

Base Case, All Programs

Technical Potential (MW, at generator-level)

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

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

Base Case, All Programs

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

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

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

Alternative Base Case with Greenfield CT Costs, All Programs

Technical Potential (MW, at generator-level)

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

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

Alternative Base Case with Greenfield CT Costs, All Programs

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

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

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

High Sensitivity Case, All Programs

Technical Potential (MW, at generator-level)

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

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

High Sensitivity Case, All Programs

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

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

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

Base Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

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

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

Base Case, NSP Proposed Portfolio

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

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

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

High Sensitivity Case, NSP Proposed Portfolio

Technical Potential (MW, at generator-level)

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

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

High Sensitivity Case, NSP Proposed Portfolio

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

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

Notes:

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

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

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The Cost-Effectiveness of Demand Response in NSP's Service Territory

PRESENTED TO

Northern States Power (NSP)

PRESENTED BY

Ryan Hledik
Ahmad Faruqui
Tony Lee
Mariko Geronimo Aydin

December 2017

THE Brattle GROUP

Introduction

In 2014, Brattle conducted a bottom-up assessment of demand response (DR) potential in Minnesota, but did not evaluate DR cost-effectiveness

- The study identified around 400 MW of traditional DR "technical potential" in the sense that it did not account for the cost-effectiveness of the DR measures
- These estimates of DR potential were not estimates of economic potential; they were inputs to the resource planning modeling process

Subsequently, a range of views on cost-effective DR potential emerged in Minnesota

- NSP has estimated between 71 and 130 MW of incremental economic potential
- The PUC has established a requirement of 400 MW of additional DR capability by 2023 and consideration of 1,000 MW of new DR by 2025

The purpose of this presentation is to revisit the 2014 Potential Study and provide Brattle's assessment of the amount of cost-effective DR available from that study

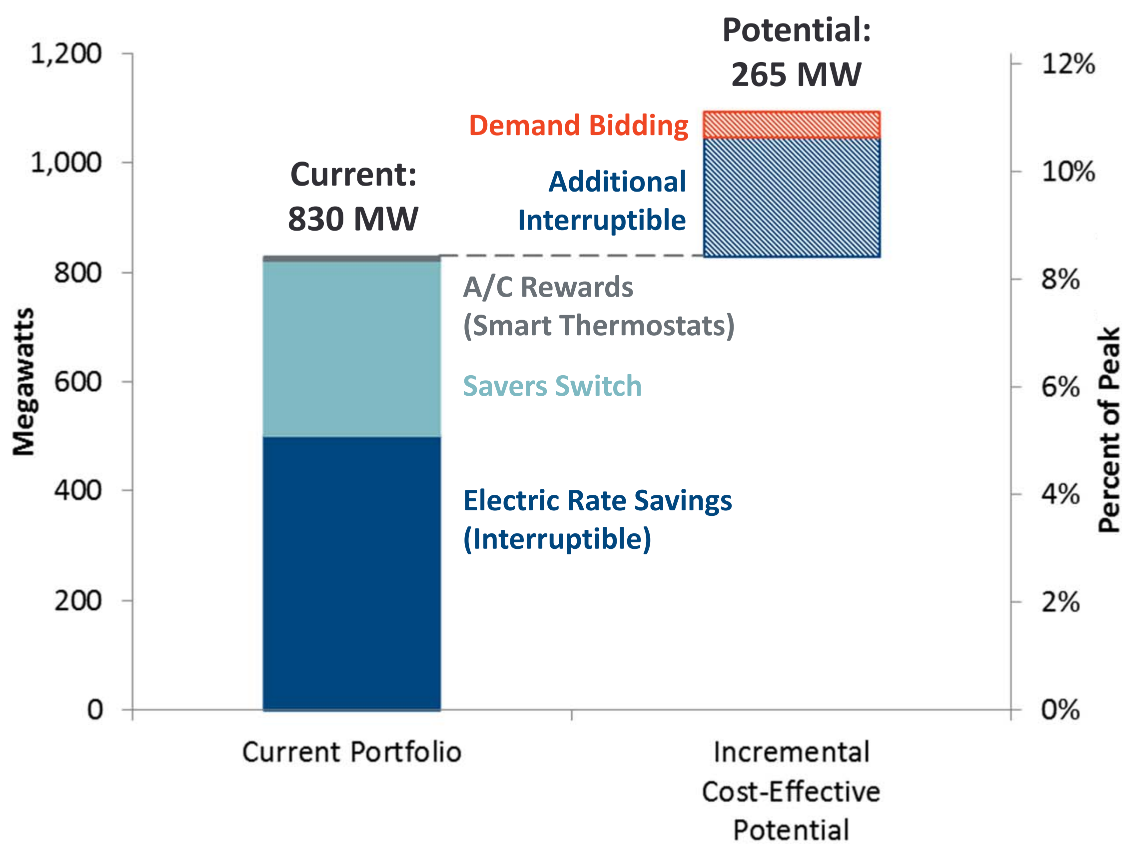
Note: 71 MW economic potential estimate identified by Staff in an October 2016 briefing paper, based on review of NSP IRP modeling data. 130 MW based on preliminary cost-effectiveness analysis conducted by NSP in 2015 (prior further detailed IRP modeling), as filed in Appendix N to the Resource Plan.

Key Findings

Comments

- NSP's current DR portfolio is one of the largest in the U.S.
- The market for traditional cost-effective DR in MN may be approaching saturation
- We identified 260 MW of incremental cost-effective DR potential among the options considered in the 2014 Study
- This estimate is subject to uncertainty; through probabilistic simulation, we estimate that there is a 75% chance the potential is under 300 MW
- There may be additional value in around-the-clock load flexibility (not quantified in this study)

Existing DR Capability and Cost-Effective Potential



Notes: Potential shown for 2023. Projected 2023 peak load of 9,848 MW was used as basis for estimating % of peak impact. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017.

Key findings (cont'd)

In spite of the limited amount of traditional incremental cost-effective DR identified in this study, there may be more value in alternative forms of demand flexibility

Emerging opportunities for "demand flexibility" include

- Renewables integration: Providing a suite of DR programs that mimic energy, capacity, and a range of ancillary services in response to rapidly changing system conditions
- Distribution benefits: Geographically-targeted programs designed to defer the need for expensive upgrades in capacity-constrained locations on the system

Accordingly, the definition of demand response should be expanded and assessed in the next IRP

- Emerging DR programs include thermal storage (e.g., grid-integrated water heaters), bring-your-own-thermostat programs, behavioral DR, electric vehicle charging control, and AMI-enabled time-varying pricing
- The definition could also be expanded to include options such as distributed battery storage, combined heat-and-power (CHP), and some types of energy efficiency

Organization of the presentation

1. **A national perspective on NSP's DR portfolio**
2. **Best practices for quantifying DR cost-effectiveness**
3. **Our assessment of NSP's cost-effective DR potential**
4. **Moving forward with DR in Minnesota—initial thoughts**

A National Perspective on NSP's DR portfolio

We benchmarked NSP's DR portfolio against other utilities in the U.S.

For context, it is helpful to first understand how NSP's portfolio compares to those of other utilities

The benchmarking analysis relied largely on DR program data from two sources: the FERC and the EIA

- From 2006 to 2012, FERC conducted a bi-annual survey of utility DR programs, including significant detail on program type, enrollment, capability, etc.
- The EIA annually collects basic aggregate data on DR enrollment and capability by major customer class; the most recent data is from 2015
- While the FERC data is older, it appears to contain fewer reporting errors and is therefore the primary data source we relied on in our analysis
- We do not anticipate that changes in utility DR programs since 2012 would materially change the broad findings of the benchmarking analysis

See Appendix A for additional detail on benchmarking analysis

NSP currently has 830 MW of DR capability

Comments

Savers Switch:

Air-conditioning direct load control (DLC) program, mostly targeting residential and small C&I customers

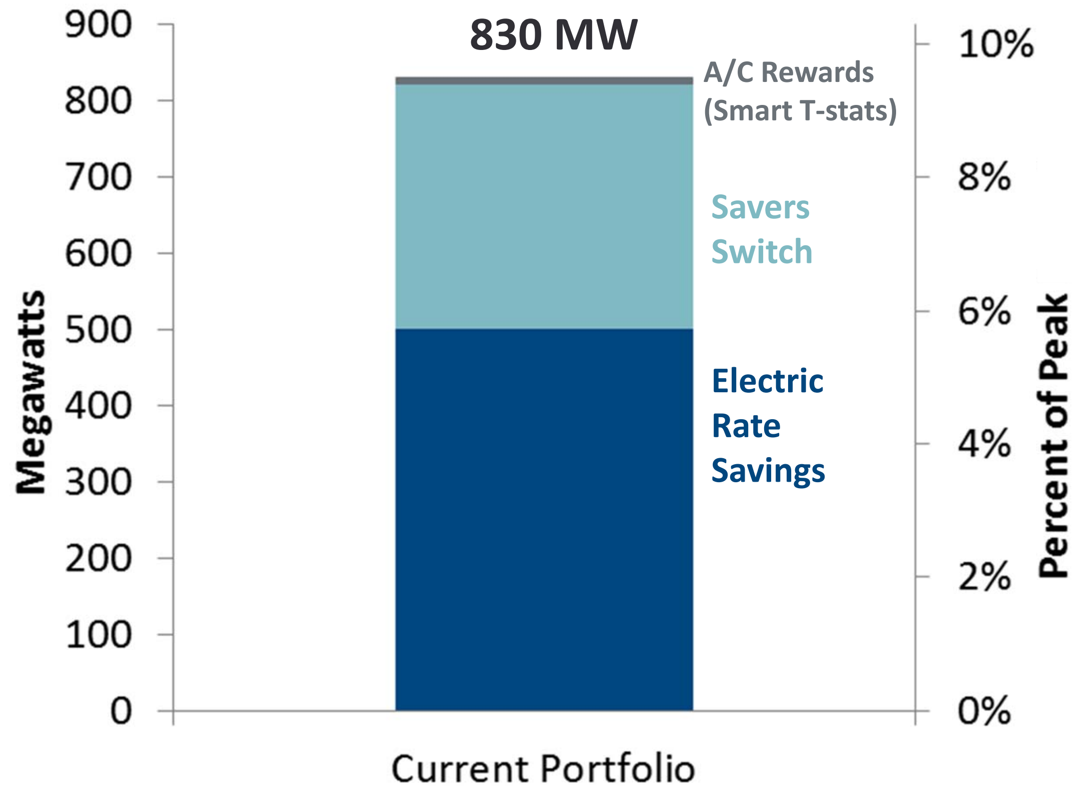
A/C Rewards:

Direct load control for customer-owned smart thermostats (residential)

Electric Rate Savings:

Interruptible tariff, targeting medium to large C&I customers

NSP DR Capability (2017)



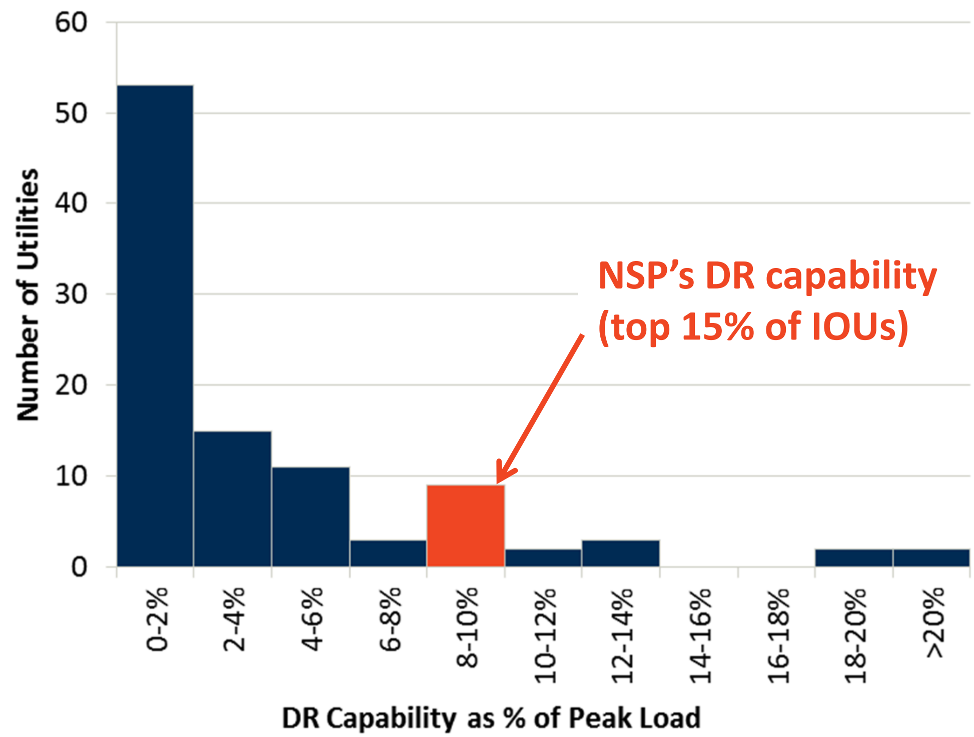
Notes: Percent of peak impact shown relative to actual 2016 peak load of 8,774 MW. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017. See appendix for further description of programs.

NSP's DR capability is in the top 15% of U.S. IOUs

Comments

- NSP's residential A/C load control program is the **2nd** most highly subscribed DR program in the country
- Around half of all eligible households are participating in NSP's Saver's Switch program
- In terms of absolute megawatts, NSP's portfolio is the **8th** largest program in the country; as a % of peak demand, it is ranked **11th**

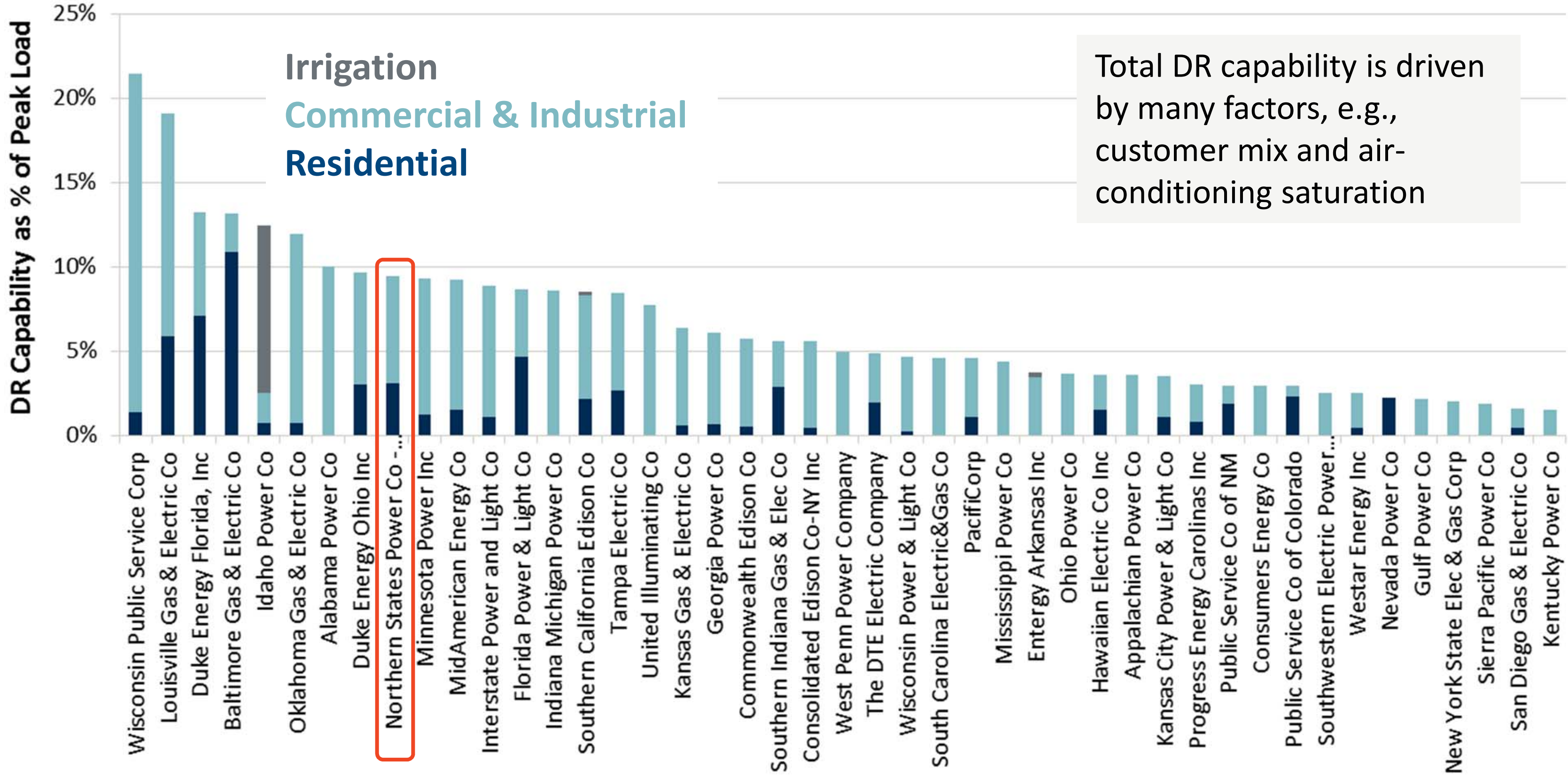
Distribution of DR Capability Among All U.S. IOUs



Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Sample of 100 U.S. IOUs. Excludes IOUs that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP's capability calculated as current portfolio divided by 2016 peak load.

NSP ranks near the top of the largest IOU DR portfolios in terms of % of peak load

DR Capability of 45 IOUs with Largest Programs (as % of Peak Demand)



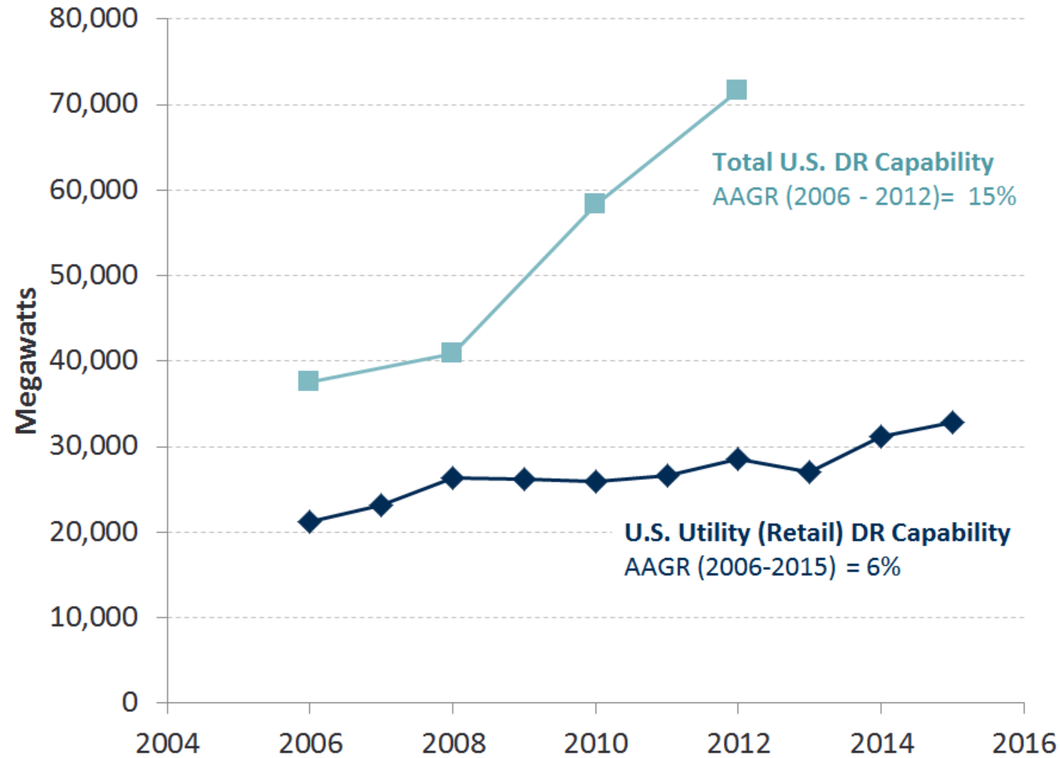
Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Sample of 100 U.S. IOUs. Excludes IOUs that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP's capability calculated as current portfolio divided by 2016 peak load.

National DR growth has been driven by ISO/RTO programs – much more than by utility programs

Comments

- There is sometimes a misperception that utility DR programs were the primary drivers of DR growth over the past decade
- While U.S. DR capability grew at an annual rate of **15%** between 2006 and 2012, most of this growth was driven by programs operated by ISOs and RTOs
- PJM accounted for roughly half of the total ISO/RTO growth, in part due to significant efforts to integrate DR into its capacity market, which offered significant payments for demand reductions
- Utility DR programs only grew at an annual rate of **6%** during that time

Distribution of DR Capability Among all U.S. IOUs



Sources and Notes: Total U.S. DR Capability reflects data reported in 2006–2012 FERC surveys, which include DR capability provided by aggregators , power marketers, and state and federal energy authorities. U.S. Utility (Retail) DR Capability reflects data reported in 2006–2015 EIA-861 data.

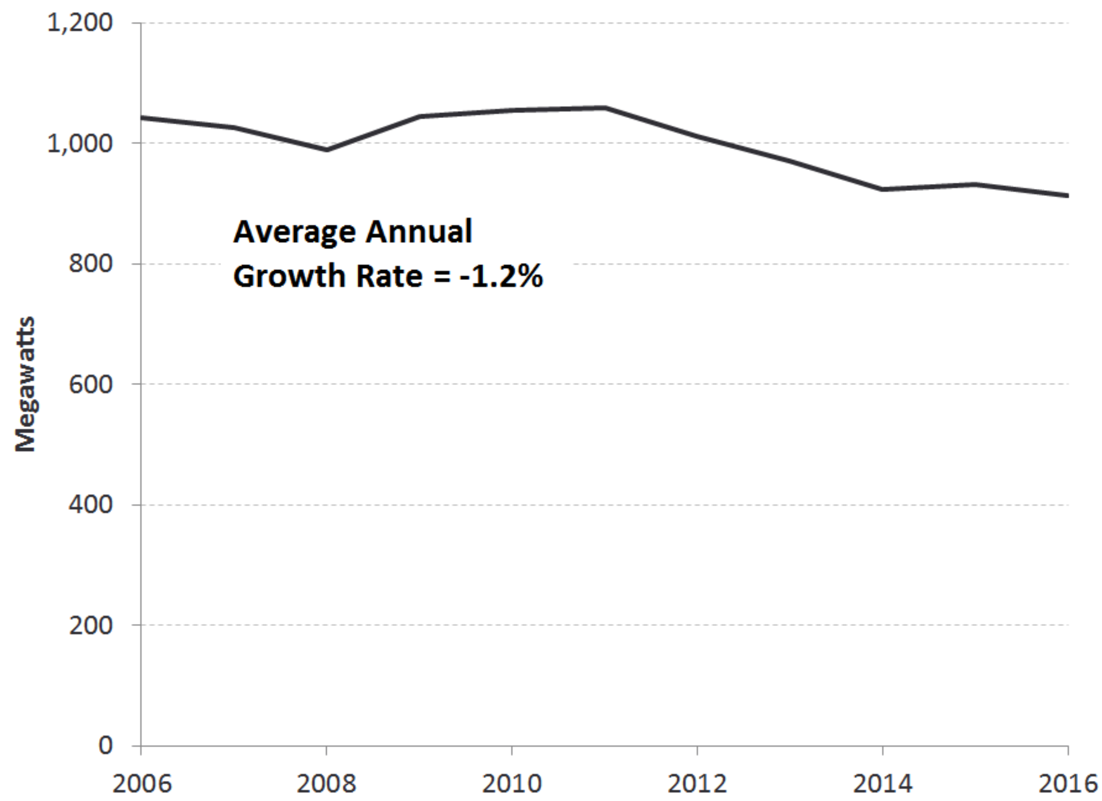
Relative to modest national growth in utility DR over the past decade, NSP's DR capability has dipped

Comments

A few explanations:

- EPA constraints on the use of backup generation as DR, imposed in 2013
- Increased utilization of the interruptible tariff program in 2016, leading to some drop-outs
- Allowing DR participants to lower their contractually committed load reduction level in anticipation of more frequent program use
- Possibly approaching market saturation due to high enrollment rates (relative to other U.S. utilities)

Historical NSP DR Capability



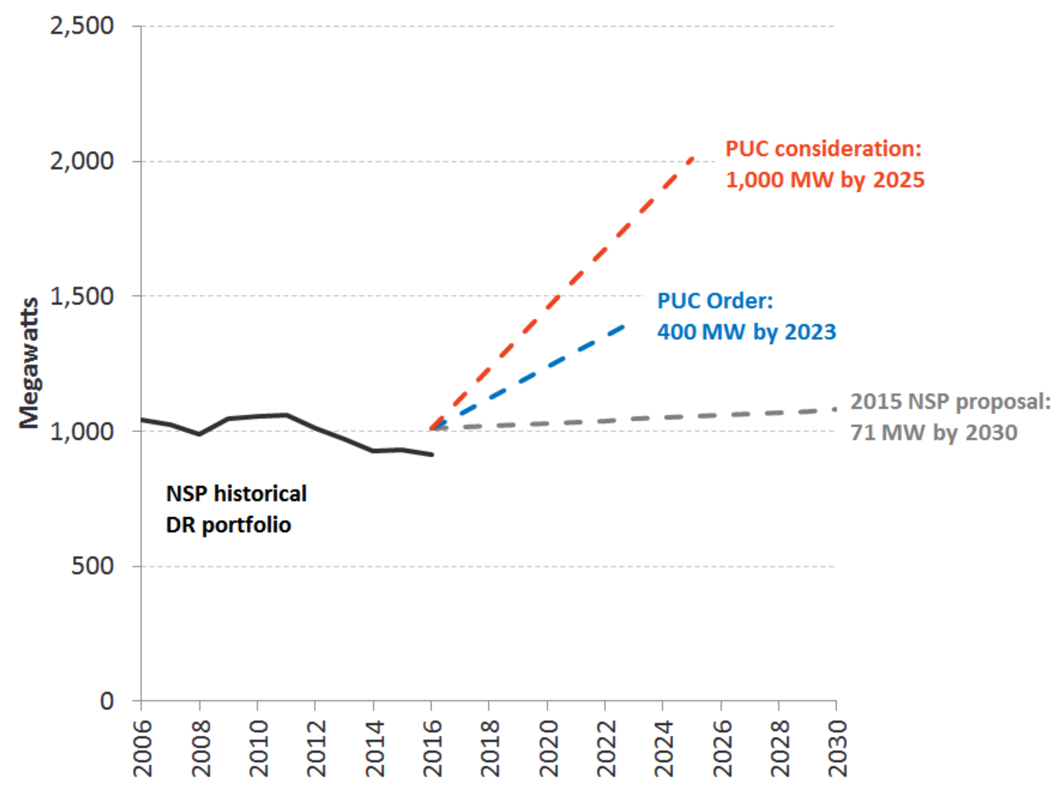
Sources and Notes: Data provided by NSP. Values shown are for entire NSP service territory.

To what extent can NSP's DR portfolio cost-effectively grow beyond recent levels?

Comments

- NSP proposed to reverse the recent historical decline with 71 MW of DR growth
- The PUC has ordered NSP to pursue 400 MW of additional DR
- The PUC's interest in 1,000 MW of new DR would significantly exceed historical observed growth rates among U.S. utilities
- **In the remainder of this presentation, we explore where NSP's cost-effective DR potential falls on this spectrum**

DR Proposals Relative to Historical Growth



Sources and Notes: Data provided by NSP. Projections of growth were established by the PUC and NSP relative to the size of the 2014 DR portfolio; therefore, they do not align with 2016 reported values.

Best Practices for Quantifying the Cost-Effectiveness of DR

There are two established options for determining the cost-effectiveness of DR

1. Incorporate DR options into the resource planning model

- Dynamically accounts for the advantages and disadvantages of DR relative to supply-side options
- However, it is difficult to implement comprehensively due to modeling and computational limitations

We rely on the screening-based approach

2. Conduct a detailed cost-effectiveness screening

- Performed outside of the IRP model
- Commonly used in regulatory proceedings to evaluate DR and EE cost-effectiveness (i.e., the Total Resource Cost test)
- Has the advantage of transparency, while still relying on the same cost and operational assumptions used in the IRP model
- Allows for a broader range of sensitivity cases around uncertain variables

The value of DR is assessed based on its ability to avoid the need for new peaking generation

The DR programs analyzed in the 2014 Potential Study are most appropriately considered substitutes for new combustion turbine (CT) capacity

CTs are "peaking" units with relatively 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 **<100 hours per year** – this constraint is either written into the 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 will run **thousands of hours per year**

The DR programs considered in the 2014 Potential 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

Note: For more data on the number of interruptions per year in a typical U.S. DR program, see SEPA, "2017 Utility Demand Response Market Snapshot," October 2017.

Comparing traditional DR to a new CT

Even though traditional DR is most comparable to a CT, there are operational differences between these resources that must be taken into account

	Demand Response	New Combustion Turbine
Total hours of availability	Roughly 100 hrs/yr	Roughly 8,200 hrs/yr (accounting for planned and unexpected maintenance)
Seasonal availability	A/C: Summer only; Other programs: year-round	Year-round
Daily window of availability	A/C: roughly 2 to 7 pm; Other programs: business hours	Any hour of day
Other considerations	Must try to limit consecutive interruptions	None
Variable cost	$0/MWh	$40/MWh
Fixed cost	$30-250/kW-yr	$50-70/kW-yr

CTs can run any hour of the year (subject to outages), whereas the timing of DR use is constrained

DR costs are largely fixed incentive payments and/or up-front investment in technology; there is not usually a cost to call a DR event

DR fixed costs include incentives, equipment, marketing & administration. CT fixed cost based on values reported in NSP's IRP. CT variable cost assumes $3/MMBtu delivered gas price, and CT heat rate of 9.75 MMBtu/MWh and VOM of $10/MWh, consistent with an 'advanced CT' in EIA's *Updated Capital Cost Estimates for Utility Scale Generating Plants* (2013).

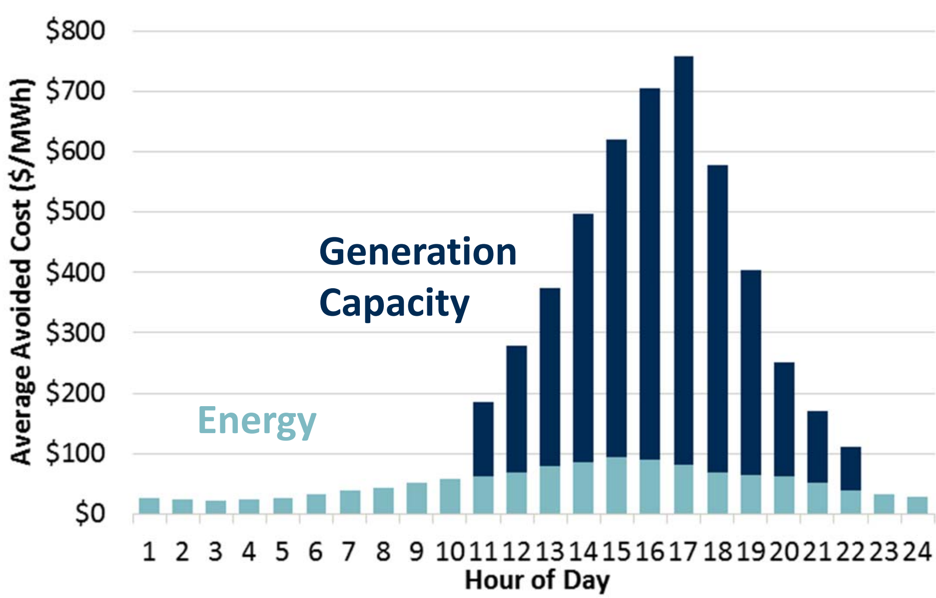
In addition to operational differences, considerations such as the dependability of the resource may also factor into the decision. See Appendix B for additional discussion of DR operational constraints

We account for the operational constraints of DR in our cost-effectiveness analysis

Comments

- Capacity costs are allocated to hours of the year proportional to the risk of capacity shortages in those hours
- In the base scenario, capacity costs are allocated to the top 100 system load hours of the year (this assumption is tested through sensitivity analysis)
- The allocation is roughly proportional to each load hour's share of total load in the hours (i.e., more capacity cost is allocated to the top load hour than the 100th)
- A similar approach has been used in California's DR cost-effectiveness protocols, and in the state's time-dependent valuation (TDV) metric for quantifying the value of energy efficiency
- The hourly allocation of capacity costs is added to 2013 hourly MISO energy market prices for NSP's service territory

Allocation of Marginal Costs: 2023 Average over Days With Capacity Value



Notes: On days without peak capacity constraints, there is no allocation of capacity value. Avoided costs shown for 2023 in nominal dollars. 2013 energy prices escalated to 2023 dollars assuming 2.2% inflation.

Avoided T&D capacity costs are also included in the analysis

Avoided T&D capacity costs are only sometimes included in assessments of DR cost-effectiveness

- Depends on DR program objectives and the physical characteristics of the utility system
- Requires higher frequency of interruptions due to lack of coincidence between transmission and distribution system peaks

Nationally, T&D investment needs are increasingly being driven by factors other than peak demand growth, limiting the T&D value of peak demand reductions. Factors commonly driving T&D investment include

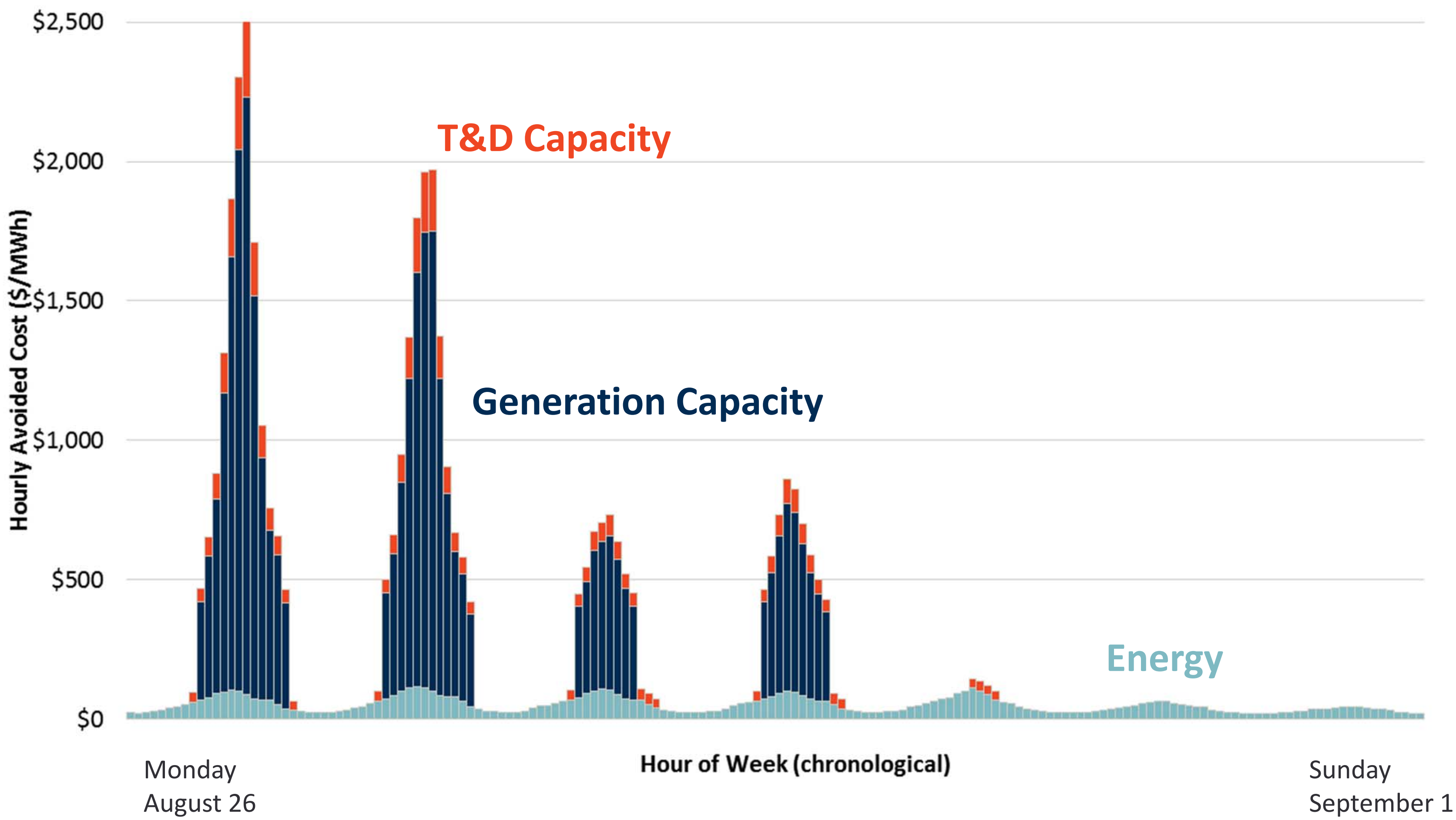
- Replacement of aging equipment
- General reliability improvements that are unrelated to peak demand
- Expansion to accommodate renewable generation

In Minnesota, there is no established approach to the treatment of T&D costs in DR cost-effectiveness analysis

- Docket No. E999/CIP-16-541 established a marginal (i.e., avoidable) T&D capacity cost of approximately $11/kW-year for NSP's energy efficiency programs
- We have adopted this as the base case marginal T&D capacity cost for DR
- In our analysis, the $11/kW-year is allocated across hours of the year in a manner similar to generation capacity, but spread over twice as many hours to account for the lack of coincidence between the overall system peak and the T&D peaks

DR is "dispatched" against the resulting hourly generation cost profile (energy + capacity + T&D)

Chronological Allocation of Marginal Costs (Illustration for Week of August 26)



Our methodology allows for robust representation of uncertainty in key variables

We first assess cost-effectiveness through "deterministic analysis"

- This is the standard industry approach
- The approach produces a point-estimate of cost-effective DR potential
- It is based on "most likely" (i.e., Base Case) values for each key variable
- However, it does not account for uncertainty in the key assumptions

We then assess cost-effectiveness through "probabilistic analysis"

- This is also known as "Monte Carlo analysis"
- It accounts for the range of uncertainty in the key variables
- A probability distribution is assigned to each uncertain variable
- Each probability distribution has an associated minimum, maximum, and most likely value based on historical data, experience from other jurisdictions, and/or our expert judgment
- A value is randomly drawn from each distribution and cost-effectiveness is estimated using those randomly selected values
- This process is repeated 2,000 times to establish a distribution of possible outcomes around the amount of cost-effective DR potential

Other key assumptions in the analysis

Avoided generation capacity cost

- $57/kW-year: This is the 2023 CT cost from NSP's IRP ($69/kW-year) adjusted downward to account for energy profit margins that the unit would earn ($12/kW-yr)
- Lower-bound of probabilistic analysis = $8/kW-yr, based on recent MISO capacity prices
- Upper-bound = $79/kW-year, based on MISO Net Cost of New Entry assumptions for CTs

Avoided T&D cost

- Base = $11/kW-yr, from 2017 EE Avoided T&D Cost Study (Discrete Method)
- Lower-bound = $0
- Upper-bound = $42/kW-year, the 2023 value from Xcel's 2016 filing for the 2017-19 Conservation Improvement Program filing (Docket No. 16-115)
- Note: The upper-bound reflects a value observed in some other jurisdictions. T&D costs are highly system-specific, therefore it does not directly reflect NSP's costs. The value is simply included to establish an upper-bound on the range of costs that may generally be avoided through system-wide reductions in demand through DR programs.

Avoided energy costs

- Based on 2013 MISO hourly day-ahead LMPs for Minnesota hub

DR program operational constraints

- Air-conditioning DLC: 15 interruptions per summer, 2 pm to 7 pm
- Other programs: 80-100 hours of interruption, minimum 1 hour duration per interruption (note: assumed interruptions are significantly more frequent than current operation of the programs)

Relevant programs

- The analysis is limited to non-pricing programs (DLC, interruptible tariffs, demand bidding)
- These are the programs that were included in the "DR supply curves" created in the 2014 study

Our Assessment of NSP's Cost-Effective DR Potential

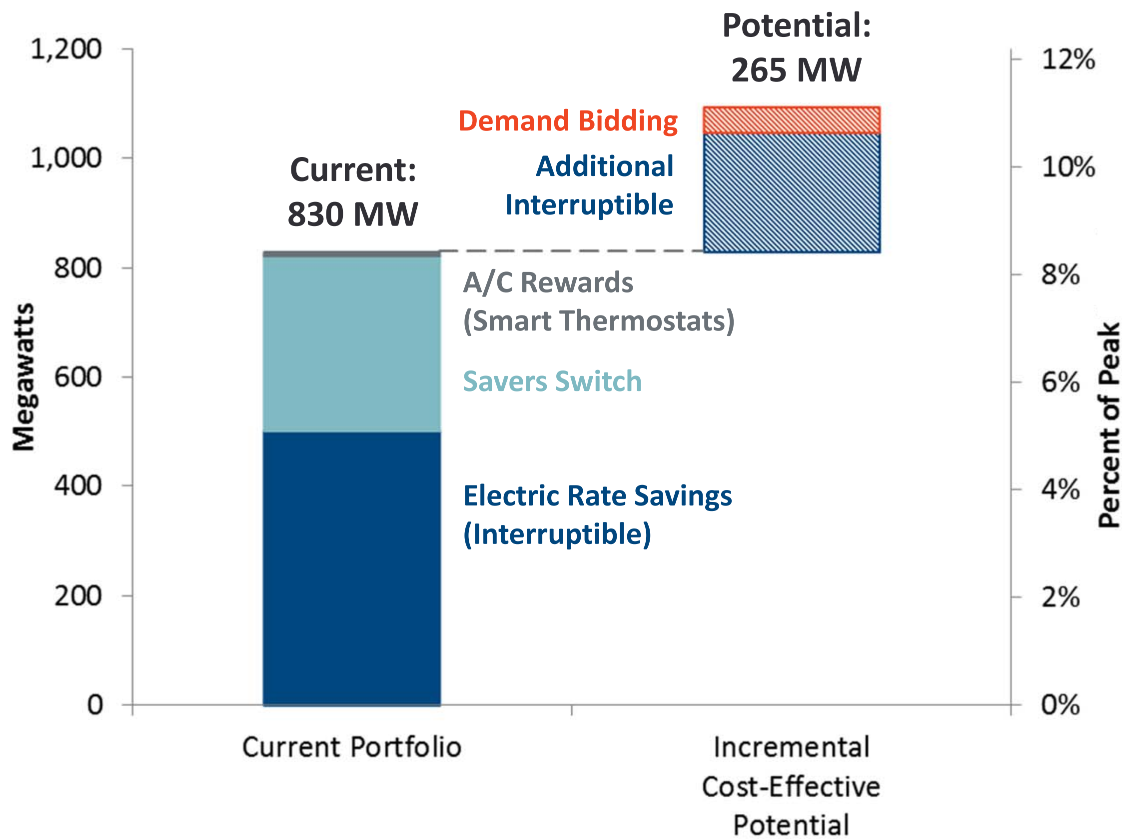
Results of Deterministic Analysis

In the Base Case, we estimate 265 MW of cost-effective potential for new DR programs

Comments

- Incremental potential resides primarily in an expansion of the interruptible tariff offering for medium C&I customers
- There is modest incremental potential in the introduction of a new demand bidding program, though given the small size of the potential it is worth considering if those resources would be better spent on other new initiatives
- Incremental growth in conventional air-conditioning DLC programs is not found to be cost-effective
- Note: We have only assessed the DR potential that is incremental to existing programs; we have not analysed the cost-effectiveness of existing programs

Existing DR Capability and Cost-Effective Potential



Notes: Potential shown for 2023. Projected 2023 peak load of 9,848 MW was used as basis for estimating % of peak impact. All impacts shown at the generator-level (grossed up for losses). A/C Rewards was launched as a pilot program in August 2017.

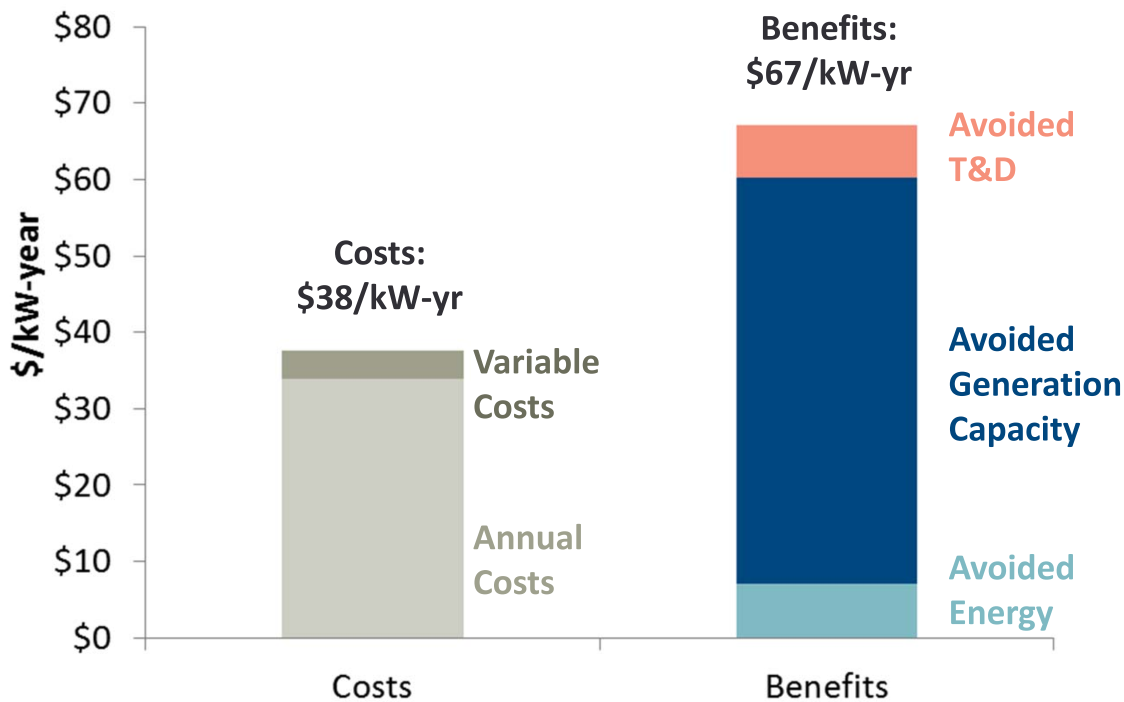
Results of Deterministic Analysis

The benefits of DR are largely avoided generation capacity costs

Comments

- The benefit-cost ratio of the portfolio of incremental cost-effective DR programs is 1.8-to-1
- Avoided generation capacity costs account for 80% of the total benefits
- The vast majority of costs are annual costs associated with participation incentive payments, program administration, and marketing/recruitment

Total Costs and Benefits of all Identified Cost-Effective Incremental DR Potential



Note: Benefits and costs are shown only for those individual DR measures with a benefit-cost ratio greater than 1.0.

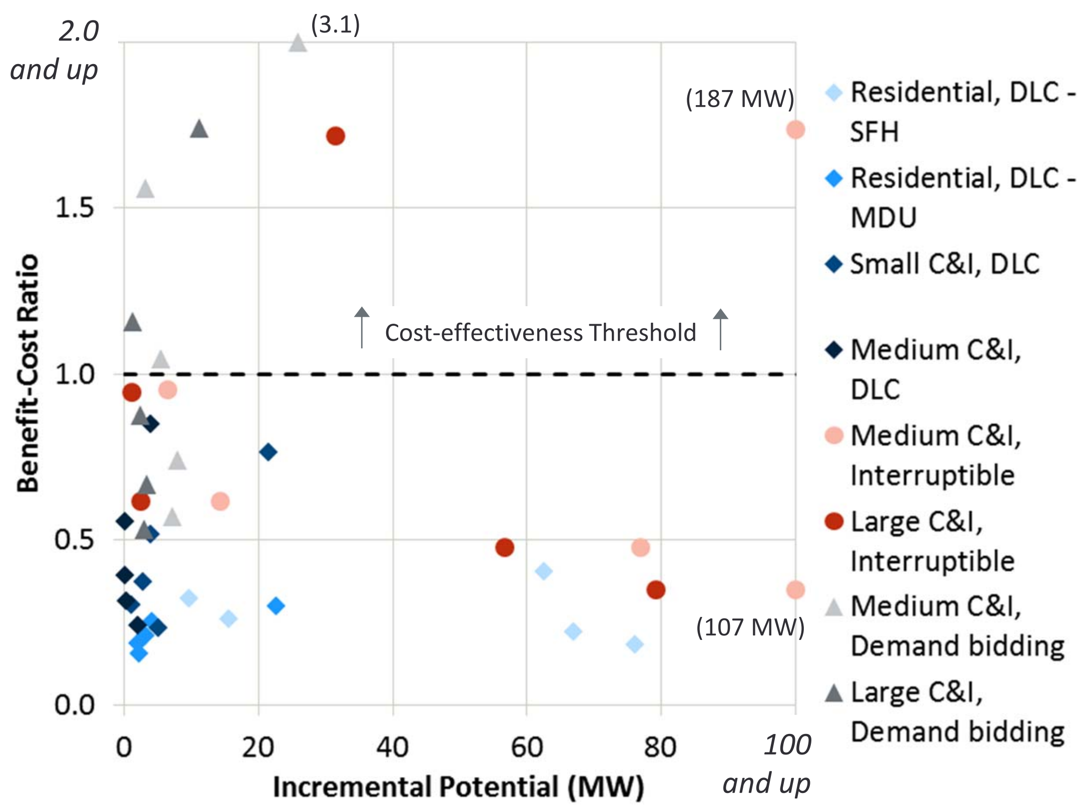
Results of Deterministic Analysis

Only a few of the analyzed programs are cost-effective

Comments

- In the chart at right, each data point represents a single incentive payment level associated with one DR program for one customer class (a range of incentive payment levels were analyzed in the 2014 Potential Study)
- Under Base Case assumptions, the most cost-effective program is Medium C&I Demand Bidding at the lowest incentive payment threshold, though the MW potential associated with this program is small
- Expanded Interruptible Tariffs have significantly more incremental cost-effective potential, particularly for Medium C&I customers, with benefit-cost ratios around 1.5

B-C Ratio and Incremental Potential of Each DR Program



Note: Each data point represents a single incentive payment level for one DR program and one customer class.

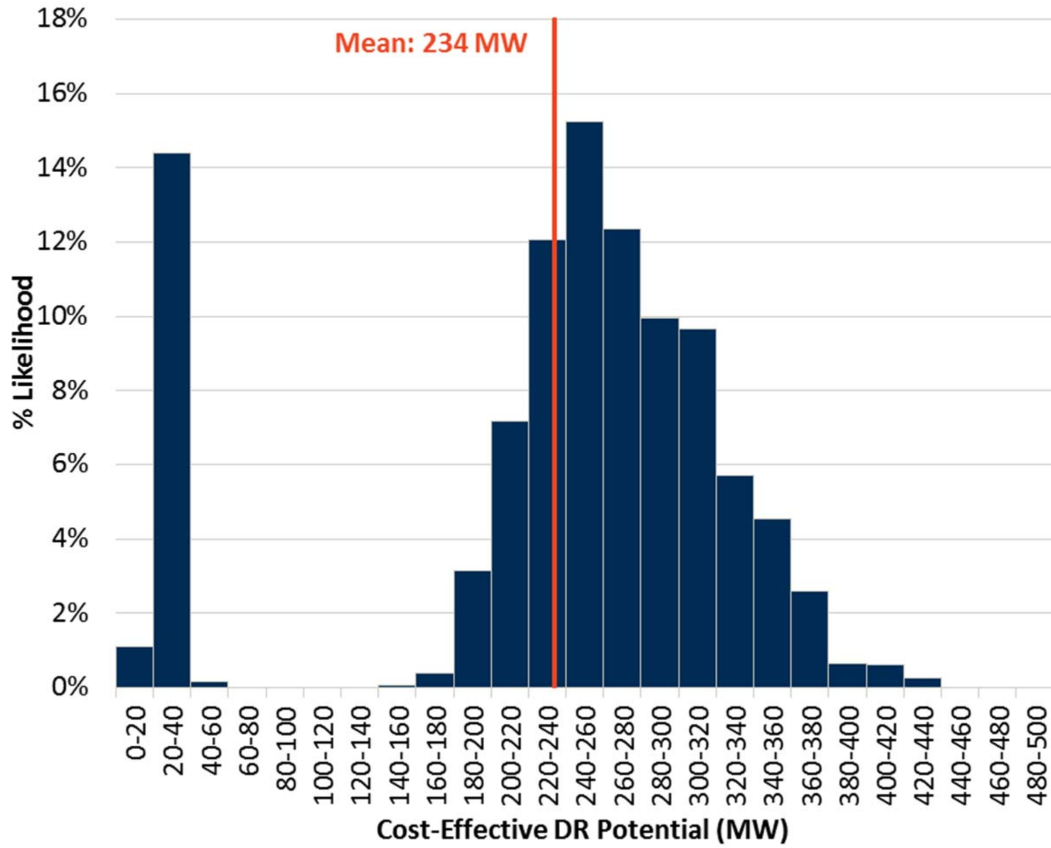
Results of Probabilistic Analysis

Accounting for uncertainty in avoided cost estimates produces consistent findings

Comments

- There is a 75% chance that cost-effective DR potential is less than 300 MW
- Whether the potential is less than 50 MW or in excess of 160 MW depends largely on whether or not the Medium C&I Interruptible Tariff program is cost-effective
- It is highly unlikely that the cost-effective potential in the programs analyzed in the 2014 Potential Study exceeds 350 MW

DR Potential Probability Distribution



Note: See Appendix B for details about the assumed range of each uncertain variable in the analysis.

Summary of findings

- NSP has already established a large portfolio of mature DR programs, which means that there are limited opportunities for incremental cost-effective growth in traditional DR
- NSP's incremental cost-effective DR potential is most likely between 200 and 300 MW
- The ability to efficiently enroll medium-sized C&I customers in an expanded Interruptible Tariff program is a key factor determining the amount of DR that is cost-effective
- This cost-effective potential of the programs analyzed in the 2014 Potential Study is less than the 400 MW to 1,000 MW target established by the PUC
- Further, there are likely to be operational challenges in achieving system peak demand reductions that are significantly beyond the capabilities of the current portfolio (i.e., an infeasible number of DR events to be called)
- Rather than pursuing a significant amount of traditional, peak demand-focused DR, there may be greater opportunities in alternative "flexible load" programs

Moving Forward with DR in Minnesota – Initial Thoughts

The cost-effectiveness findings in this presentation are not the end of the story

In spite of the limited amount of traditional incremental cost-effective DR identified in this study, there may be more value in alternative forms of demand flexibility

Renewables integration presents one such opportunity

- Minnesota has a goal of integrating 40%+ renewables
- This will require more than simple peak load reductions – it will require availability during non-peak hours, fast response times, and the ability to ramp quickly
- DR and other behind-the-meter options have the potential to provide these services

Avoided distribution costs are another emerging opportunity for DR

- There is growing interest in the use of demand-side resources to address very location-specific constraints on the distribution system
- If adequate enrollment can be achieved, it may be possible to defer the need for upgrades in locations where capacity constraints are a near-term concern
- This concept is largely in the trial phase and requires a novel approach to DR deployment and evaluation; however it is worth consideration in future DR studies

NSP's next DR potential study will include an expanded definition of DR

Which "demand flexibility" options are of interest to stakeholders?

An expanded definition of demand flexibility could possibly include:

- Distributed battery storage
- Thermal storage (incl. grid-integrated water heaters)
- EV charging control
- Some types of energy efficiency
- Bring-your-own-thermostat (BYOT) programs
- Behavioral DR
- AMI-enabled dynamic pricing

Appendix A:
Details of DR Benchmarking Analysis

Description of National DR Data

We analyzed two national DR datasets: FERC's surveys of utilities in its *Assessment of DR and Advanced Metering* Staff Reports (2006–2012) and EIA-861 Demand Response data files (2006–2015)

- In 2006–2012, FERC surveyed utilities every two years on their individual DR programs to inform its annual *Staff Report*
- The EIA has conducted the survey for many years , but annually and on aggregate DR portfolios
- Both datasets survey IOUs, munis, coops, and other load-serving entities. Shared data fields include annual capability and actual peak reduction from DR, number of customers enrolled, maximum demand from DR customers, and program costs
- To analyze DR capability as % of peak load, we also compiled peak load data reported in the EIA-861 data files

Description of National DR Data (cont.)

The FERC and EIA datasets provide information on DR penetration across utilities nationwide, but there are limitations:

- In our experience, these types of national datasets can have some reporting errors and inconsistencies
- We found the FERC survey data to more accurately represent utility DR capabilities (including NSP's) so we chose to benchmark using the latest FERC survey data available (2012)
- The % of peak metric is based on a single year of reported actual peak load
  - To the extent utilities do not adjust DR MW estimates with load, resulting % may appear high in a low load year, and low in a high load year

Peer Group Selection Criteria

We selected a subset of similarly situated utilities to compare NSP's DR portfolio to those of its peer group

MISO peer group represents large IOUs in nearby states

- Neighboring states in the Upper Midwest (MN, WI, IA, MI)
- Investor-owned utilities
- Peak demand greater than 1,000 MW

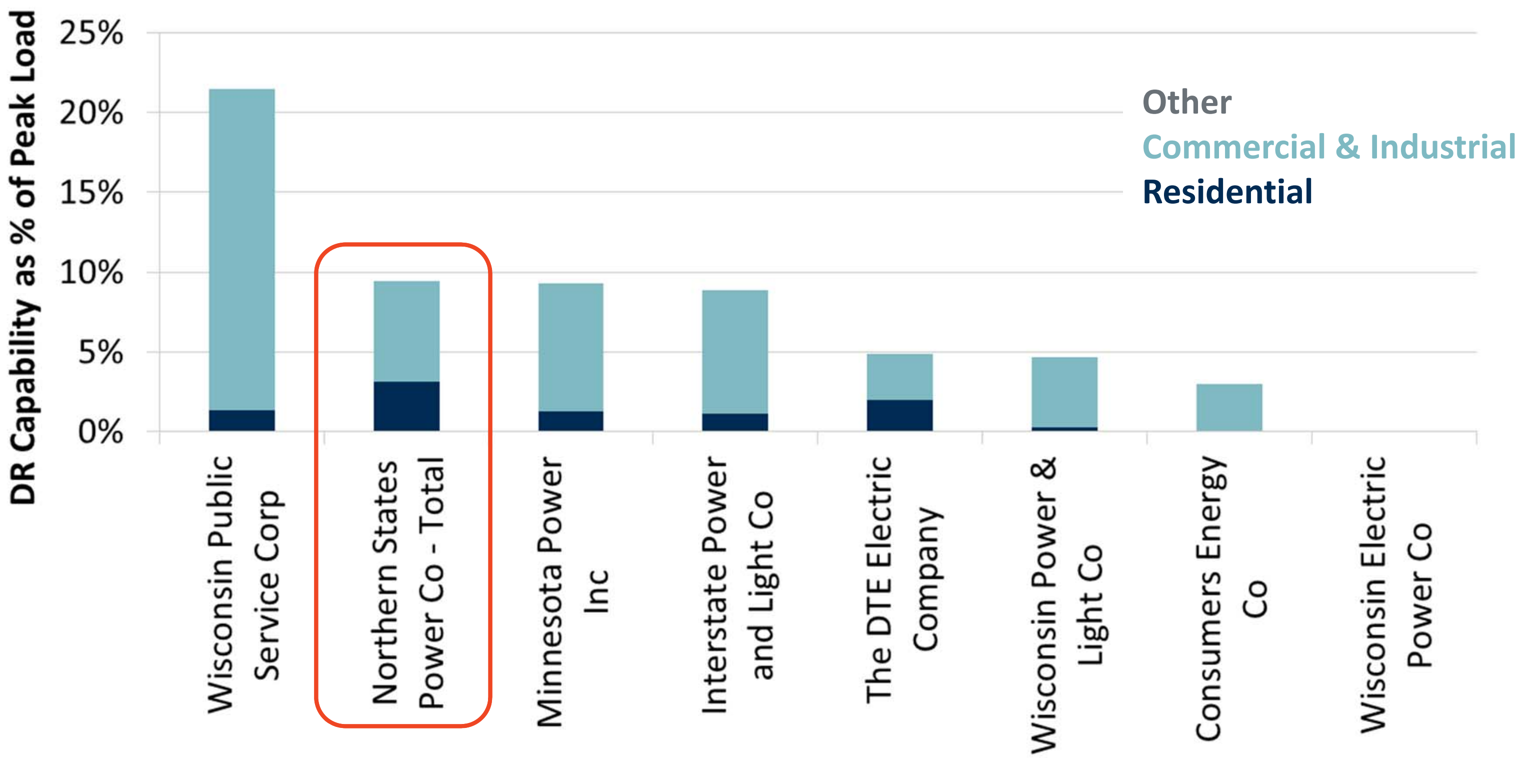
Other RTO peer group represents large IOUs with comparable peak load and serving major cities

- RTOs with capacity market (NYISO, PJM, ISO-NE)
- Investor-owned utilities serving major cities
- Peak demand greater than 5,000 MW

NSP Compared to MISO Peer Group

NSP ranks highly among MISO IOUs in total and residential DR capability.

- NSP has the most "nameplate" DR capability (830 MW) of all MISO IOUs, and ~300 MW beyond that of the next closest IOU (DTE: 550 MW, WPSC: 500 MW).
- WPSC has a larger portfolio as a % of peak demand, though lower enrollment as a % of its total customer base due to a portfolio predominantly composed of C&I

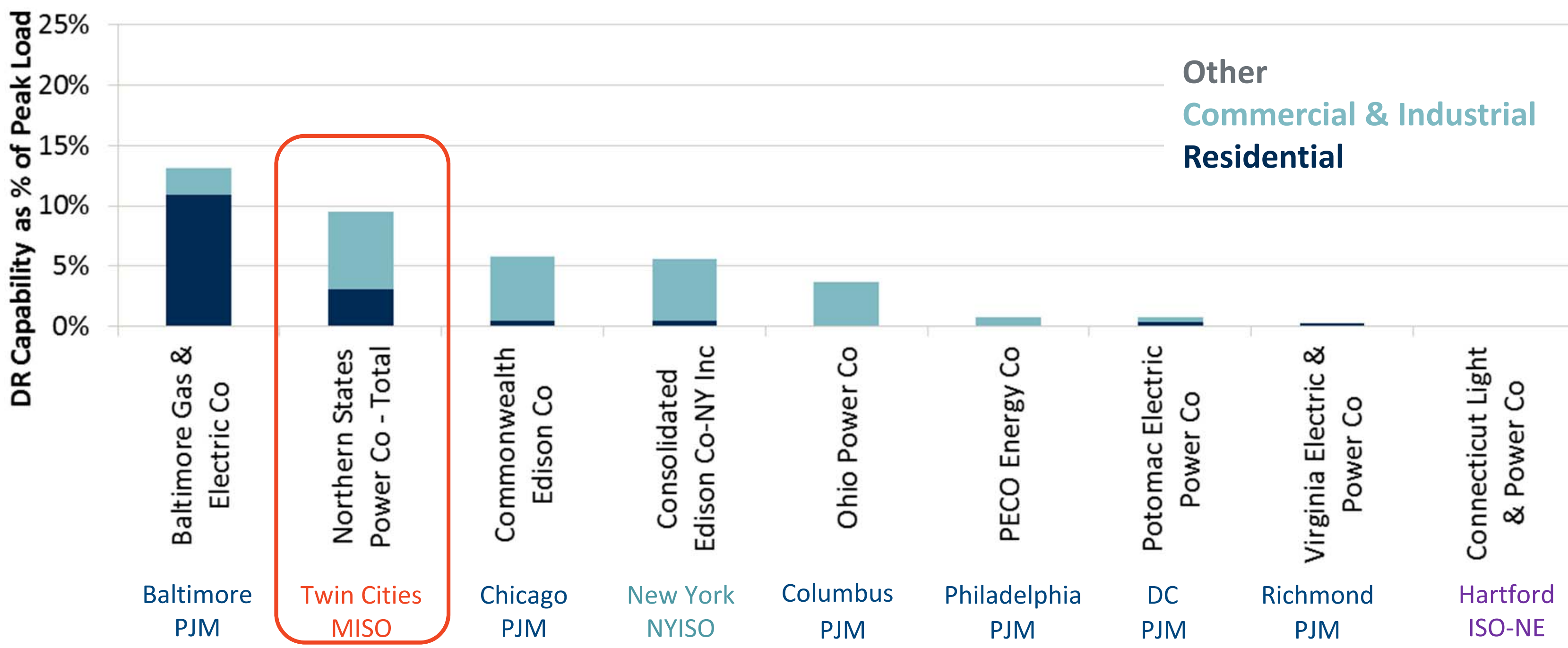


Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Excludes peak reduction capability from time-of-use programs because these loads are not controllable. NSP's capability calculated as current portfolio divided by 2016 peak load.

NSP Compared to Other RTO Peer Group

NSP compares favorably to large IOUs in markets with more lucrative DR products (PJM and NYISO)

- BG&E (920 MW) and ComEd (1,360 MW) are the only other IOUs in peer group with comparable total MW DR capability. Outside of peer group, NSP ranks **8th** nationally in total DR capability, and **11th** nationally in DR capability as share of peak.



Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Excludes peak reduction capability from time-of-use programs because these loads are not controllable. Share in residential DR does not control for differences in overall load composition. For example, BG&E total energy sales were 75% residential compared to NSP energy sales which were only 29% residential. NSP's capability calculated as current portfolio divided by 2016 peak load.

NSP's existing DR portfolio ranks highly against those of other large IOUs

NSP DR Capability Compared to IOU Peer Group

2012 FERC Survey

	RTO	State	Peak Load (MW)	DR Peak Reduction Capability: Total DR (MW)	Res. (MW)	C&I (MW)	**Total DR (% of peak)**	Share of DR MW: Res. (%)	C&I (%)	Customers Enrolled in DR: Res. (customers)	Total (customers)
Northern States Power Co - Total	MISO	MN	8,774	830	270	560	**9%**	33%	67%	446,808	467,161
Wisconsin Public Service Corp	MISO	WI	2,347	504	32	473	**21%**	6%	94%	25,375	25,861
Minnesota Power Inc	MISO	MN	1,633	152	20	132	**9%**	13%	87%	7,217	7,761
Interstate Power and Light Co	MISO	IA	3,130	279	34	245	**9%**	12%	88%	48,928	49,115
The DTE Electric Company	MISO	MI	11,182	547	219	328	**5%**	40%	60%	281,031	281,689
Wisconsin Power & Light Co	MISO	WI	2,851	134	7	127	**5%**	5%	95%	10,700	10,800
Consumers Energy Co	MISO	MI	8,387	246	0	246	**3%**	0%	100%	0	30
Wisconsin Electric Power Co	MISO	WI	6,294	0	0	0	**0%**	-	-	0	152
Baltimore Gas & Electric Co	PJM	MD	7,002	919	763	157	**13%**	83%	17%	405,944	411,064
Commonwealth Edison Co	PJM	IL	23,601	1,357	116	1,241	**6%**	9%	91%	83,537	87,312
Consolidated Edison Co-NY Inc	NYISO	NY	5,492	305	23	282	**6%**	8%	92%	22,395	32,202
Ohio Power Co	PJM	OH	9,670	351	0	351	**4%**	0%	100%	0	8
PECO Energy Co	PJM	PA	8,549	64	0	64	**1%**	0%	100%	0	118
Potomac Electric Power Co	PJM	DC	6,674	50	25	25	**1%**	50%	50%	25,000	72,769
Virginia Electric & Power Co	PJM	VA	16,787	50	50	0	**0%**	100%	0%	28,000	28,013
Connecticut Light & Power Co	ISONE	CT	5,280	5	0	5	**0%**	0%	100%	0	12
All MISO IOUs in Survey Data (12 IOUs)			55,231	2,978	718	2,260	**5%**	24%	76%	880,849	908,232
All U.S. IOUs in Survey Data (100 IOUs)			456,353	19,942	5,289	14,273	**4%**	27%	72%	4,653,575	4,838,625
All Utilities in Survey Data (387 Utilities)			563,074	27,383	7,015	19,346	**5%**	26%	71%	5,801,247	6,025,979

Sources and Notes: FERC, *2012 Assessment of Demand Response and Advanced Metering* and EIA 861 peak load data. Excludes utilities that did not participate in the FERC survey, and excludes peak reduction capability from time-of-use programs because these loads are not controllable. Res. and C&I DR do not add up to Total DR for All U.S. IOUs and All Utilities because Other DR is excluded from table. NSP's capability calculated as current portfolio divided by 2016 peak load.

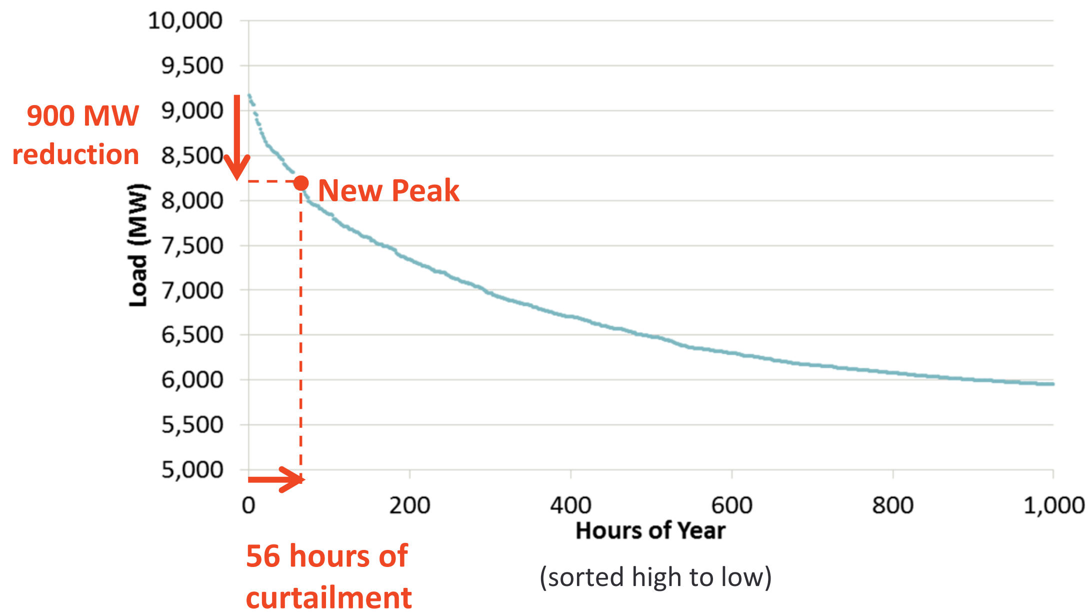
Appendix B: Additional Considerations in Assessing DR Potential

The operational constraints of DR programs have implications for the ability to reduce peak demand

Comments

- Reducing system peak demand by 900 MW (roughly the size of NSP's current DR portfolio) requires load reductions in the top **56** hours of the year
- Otherwise, one of these top **56** hours will set the new peak at a level that exceeds the target
- In 2013, those top **56** hours occurred on **8** different days of the year

NSP's 2013 Load Duration Curve



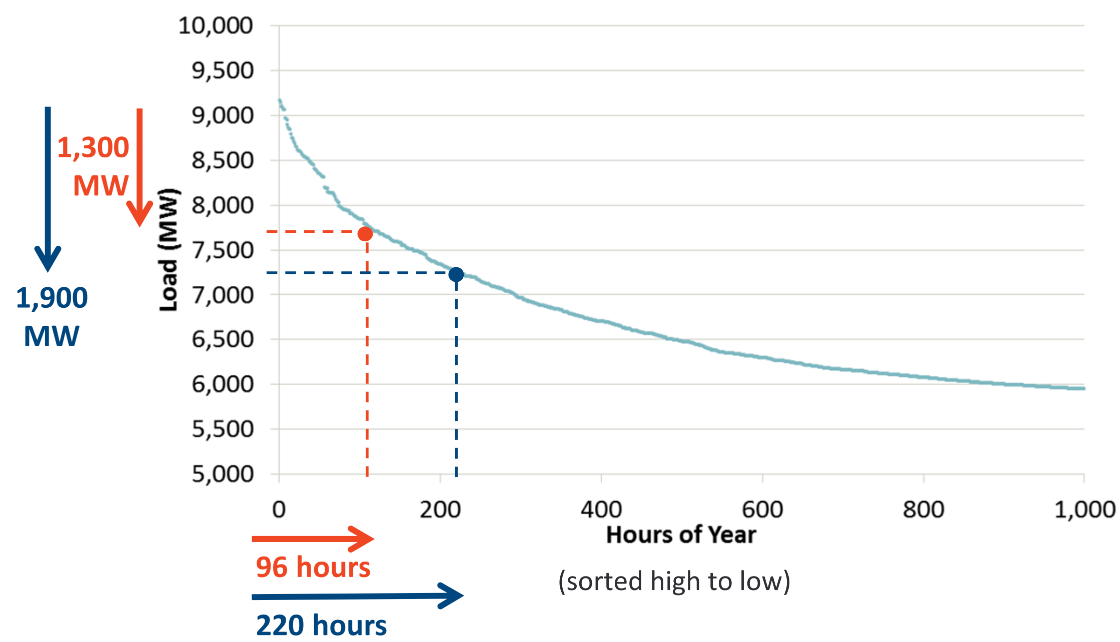
Sources and Notes: 2013 system load for NSP service territory, provided by Xcel. 2013 was chosen as the year for this example, because it was the year with the highest peak demand in the past several years.

Achieving larger load reductions requires that DR be dispatched during more hours of the year

Comments

- A **1,300 MW** reduction (the PUC's target for NSP's DR capability) would require that DR be dispatched during at least **96** hours of the year
- In 2013, those hours spanned **13** days of the year, **12** different hours of the day, and **5** days of the week
- DR events would need to be called on **5** consecutive days in this scenario
- Achieving a **1,900 MW** peak reduction would require that DR be utilized during **27** different days of the year
- The number and frequency of necessary interruptions is significantly higher in other recent years, when peak load was less concentrated in the top hours

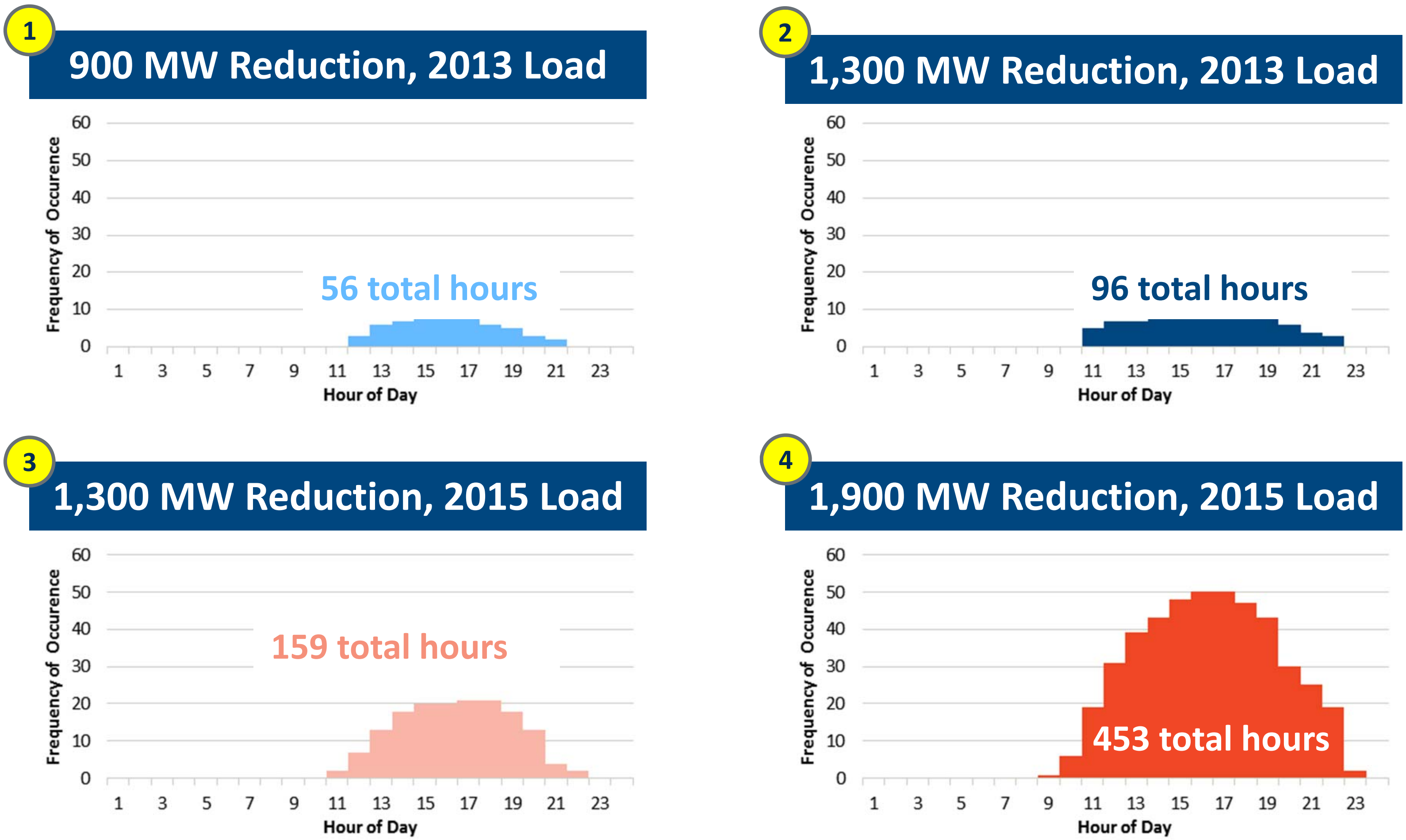
NSP's 2013 Load Duration Curve



Sources and Notes: 2013 system load for NSP service territory, provided by Xcel. 2013 was chosen as the year for this example, because it was the year with the highest peak demand in the past several years. Results will vary depending on the year being analyzed.

Achieving very large peak demand reductions will likely exceed the capabilities of traditional DR

Hours of Day When DR Would Need to be Utilized



Note: The charts illustrate the distribution of hours when a DR event would need to be called in order to achieve the specified load reduction for the specified year's load shape.

Appendix C:
Cost-Effectiveness Analysis Assumptions

Additional assumptions

Hours of generation capacity value allocation

- Base case = Top 100 load hours
- Min (probabilistic analysis) = Top 25 hours
- Max (probabilistic analysis) = Top 250 hours

Load year

- 2013, selected because it represents the highest peak demand in recent historical data (2012 through 2015) and also has the peakiest load shape, contributing to a slightly higher value of DR than other years

Planning reserve margin

- For the purposes of estimating avoided generation capacity costs, impacts are grossed up by the planning reserve margin
- This accounts for a reduced planning need
- NSP’s planning reserve margin for its own system peak is 2.41% due to non-coincidence with the MISO peak

Line losses

- Impacts in the 2014 Potential Study were reported at the generator level; no gross-up was needed to account for line losses

Energy margin

- According to NSP modeling, the net energy margins (sum of marginal energy price minus the unit’s variable costs over all operational hours) for a new CT in the study years is roughly between $6 and $18/kW-year
- We assume $12/kW-year, the middle of this range

Participation

- Base case impacts were based on the supply curve values produced for the 2014 Potential Study
- In an appendix to that study, we conducted a sensitivity case for each DR program’s participation assumption, based on participation rates used in the 2009 FERC Assessment of DR Potential (which were based on the 75th percentile of national DR enrollment rates)
- For all but one program, the sensitivity case participation rates were lower than those used in the 2014 study
- For the probabilistic assessment in cost-effectiveness analysis, we used the absolute value of the difference between the FERC values and the 2014 Potential Study values to create upper- and lower-bound participation rates.
- The upper- and lower-bounds range anywhere from +/-5% of the Base participation rate, to +/-82%, depending on the program analyzed

Additional methodological notes

The scope of this study was only to assess the cost-effectiveness of the DR programs analyzed the 2014 Potential Study

We did not analyze time-varying pricing programs, since NSP has not deployed AMI

We have only assessed the DR potential that is incremental to existing programs; we have not analyzed the cost-effectiveness of NSP's existing DR portfolio

Our analysis is conducted from the standpoint of DR costs and benefits in 2023, the year by which the PUC has required NSP to add 400 MW of DR (and the year before the projected need for new peaking capacity, per the IRP)

Appendix D:
Additional Background

NSP's DR programs

Savers Switch:

- Central air-conditioning DLC
- Compressor switch with 15- to 20-minute cycling
- Additional option to enroll water heater
- Residential and business customers
- Residential incentive = 15% savings on energy charges (June – Sept)
- Business incentive = $5/ton of A/C (June – Sept)
- 321 MW of peak demand reduction capability (2016)

A/C Rewards:

- DLC for customer-owned smart thermostats
- Temporary modification of thermostat set point
- Residential
- Incentive = $25/yr, plus up to $125 rebate toward purchase of select smart thermostats or $75 payment for registering an installed smart thermostat
- 8 MW of peak demand reduction capability (2016)

Electric Rate Savings:

- Interruptible tariff, customer must reduce load to pre-specified level
- Medium and large C&I customers
- Minimum 50 kW demand reduction for eligibility
- Control periods can occur any time of year
- Incentive = $5.86 to $8.44 per kW of controllable load (June-Sept), $1.75 to $4.33 per kW (Oct-May)
- 501 MW of peak demand reduction capability (2016)

The 2014 DR Potential Study

The purpose of the study was to:

- Quantify the potential peak demand reduction that could be achieved through an expanded portfolio of demand response (DR) options in NSP's service territory, without cost considerations
- Identify future DR opportunities for NSP

We considered 22 different programmatic DR options and segmented the market into four customer classes

- 9 of the options were existing programs and 13 were possible new options
- 10 were considered "traditional" DR options and 12 were AMI-enabled options

We also estimated program costs which, when combined with the peak reduction estimates, produced a "supply curve" of traditional DR resources that could be used as input to NSP's integrated resource planning (IRP) process

Note: Our DR potential estimates did <u>not</u> account for the cost-effectiveness of the DR measures

The 2014 Potential Study (cont'd)

The following DR options were analyzed

<u>Currently offered options</u>

- **Direct load control (DLC):** Participant's central air-conditioner is remotely cycled using a switch
- **Interruptible rates:** Participants agree to reduce demand to a pre-specified level and receive an incentive payment in the form of a discounted rate
- **Time-of-use (TOU) rates:** NSP currently offers TOU rates, which are replaced in our analysis by re-designed rates (see discussion below)

<u>Possible new options</u>

- **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
- **Critical peak pricing (CPP) rates:** Provides customers with a discounted rate during most hours of the year, and a much higher rate (typically between 50 cents/kWh and $1.00/kWh) during peak hours on up to 10 or 15 days per summer; can be offered with "enabling technology" which automates load reductions in response to the higher priced hours
- **Redesigned time-of-use (TOU) rates:** Existing TOU rates were redesigned to be more manageable and targeted, with a shorter peak period and a revised peak-to-off-peak price ratio

Xcel Energy Demand Response Offerings

2017-2019 Stakeholder Engagement Process Summary Report

MN PUC Docket No. E-002/RP-19-368

May 2019

Co-convened by the Great Plains Institute and Center for Energy and Environment

About this Report

AUTHOR

Trevor Drake, Great Plains Institute

ATTRIBUTION OF COMMENTS

This document provides a synthesis of remarks by stakeholders at seven meetings between December 2017 and January 2019. The notes do not indicate consensus among the group, but rather are meant to capture the collective discussion and key points raised by participants. No view should be attributed to any specific individual or organization.

The stakeholder engagement process and this resulting summary are intended to support, but not replace, important discussions within the formal regulatory process. Comments summarized as part of this report represent a perspective at a specific point in time and are not intended to limit the ability of any party to take any position in future regulatory proceedings.

ACKNOWLEDGEMENTS

GPI and CEE would like to thank Xcel Energy for the opportunity to serve as third-party facilitators for this stakeholder engagement process. We would also like to thank the stakeholders and speakers who attended and thoughtfully participated in the seven meetings that were convened as part of this process.

ABOUT THE CO-CONVENERS

Great Plains Institute: A nonpartisan, nonprofit, Great Plains Institute is transforming the energy system to benefit the economy and environment. For the last 20 years, the institute has worked on energy solutions that strengthen our communities, grow the economy, and improve lives while reducing emissions. More information is available at www.betterenergy.org

Center for Energy and Environment: The Center for Energy and Environment is a clean energy nonprofit with special expertise in energy efficiency that stretches back nearly 40 years. CEE provides a range of practical and cost-effective energy solutions for homes, businesses, and communities to strengthen the economy while improving the environment. More information is available at www.mncee.org

QUESTIONS ABOUT THIS REPORT

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Contents

I. Introduction

BACKGROUND ON DEMAND RESPONSE

Across the United States, profound changes are affecting the way that electric systems are being planned and operated. These changes include a shift away from power generation from large power plants towards greater deployment of variable, distributed electricity generation from wind and solar, increasing demand for electrified transportation and buildings, a desire for more consumer choice, and pressure to reduce carbon emissions and environmental impacts. Utilities, their regulators, and energy system stakeholders across the nation are grappling with how to address these changes and pressures while attending to the need to operate electric systems safely, reliably, and affordably.

Demand response encompasses a broad set of technologies and approaches that are used to modify customers' demand for electricity to provide system-level services. Demand response programs have the capabilities to help respond to many, if not all, of the profound changes and pressures affecting the electric system today. While demand response has historically been used to incentivize customers to curtail their demand for electricity during emergency events, it can also be used for other purposes, including enhancing overall reliability, reducing operations costs by deferring or avoiding infrastructure investments, shaping loads to accommodate variable electricity generation resources like wind and solar, providing choice to customers in how much they pay for electricity based on when they use it, and providing ancillary services such as frequency regulation.

Electric utilities across Minnesota already operate several demand response programs, ranging from interruptible tariffs that provide commercial and industrial customers a lower electricity rate in return for the ability to curtail demand during emergency events, to electrified home water heaters and air-conditioners that can be controlled by utilities to manage aggregated residential electricity loads across many customers at once.

DEMAND RESPONSE REQUIREMENT FOR XCEL ENERGY IN MINNESOTA

In its January 11, 2017 Order approving Xcel Energy's 2016-2030 Resource Plan, the Minnesota Public Utilities Commission required the electric utility to include in its next resource plan the procurement of 400 megawatts of additional demand response resources by 2023 and to evaluate the cost-effectiveness of 1,000 MW of additional demand response by 2025. In December 2017, Xcel Energy hired the Great Plains Institute (GPI) and Center for Energy and Environment (CEE) to convene stakeholder meetings to solicit input on the development of its demand response offerings towards achieving compliance with the Commission's order. Xcel Energy also hired The Brattle Group to conduct an updated demand response potential study including cost-effectiveness analysis, which became available near the end of the stakeholder engagement process.

This report summarizes key points of discussion and feedback received throughout the stakeholder engagement process, which took place across seven meetings from December 2017 to January 2019.

II. Process Overview

ORIGINAL PROCESS GOALS

Beginning in December 2017, Xcel Energy initially established the following goals to help guide the stakeholder engagement process that would be co-convened by GPI and CEE:

- Create a base understanding of demand response efforts in Minnesota compared to other areas of the nation.
- Discuss the scope of demand response efforts in Minnesota.
- Provide an opportunity to share ideas amongst stakeholders regarding demand response efforts within and outside Xcel Energy's service territory.
- Brainstorm new and updated program ideas for Xcel Energy's portfolio.
- Examine opportunities and challenges to new demand response technologies and any policy changes needed for success.

PROCESS REVISIONS

The above set of goals provided a helpful and broad starting point for stakeholder discussions. However, after the first two meetings, it became clear that it would be most valuable to focus stakeholder discussions specifically on the new or expanded demand response offerings that Xcel Energy could deploy to achieve compliance with the Commission's order. Therefore, after the second meeting, GPI, CEE, and Xcel Energy worked together to restructure the process around the following revised set of goals:

1. Identify a set of consensus-based design characteristics for any new or expanded demand response program or portfolio or programs.
2. Understand and discuss the results of The Brattle Group's demand response potential study in the context of the proposed design characteristics.
3. Apply the design characteristics to the list of Xcel Energy's potential new and expanded demand response programs and identify which programs comport with the agreed-upon design characteristics.
4. Review and offer feedback to the demand response programs that Xcel Energy is developing to comply with the commission's order, considering both the design principles and the results of the potential study.

This report details the group's progress in working to achieve these goals. Importantly, Xcel Energy stated to the group that their next Resource Plan will assume the additional demand response as required in the Commission's order, but that not all programs that will be deployed to achieve compliance would be fully developed by the time that the 2020-2034 Resource Plan is filed. Therefore, while the group did develop design characteristics—in the form of the Design Principles and Filing Objectives listed in this report—and discussed them with regard to Xcel Energy's proposed DR offerings, many of those offerings were still in development at the time of these meetings and could not be fully evaluated. Therefore, the Design Principles and Filing Objectives can be especially useful to provide ongoing guidance as those offerings are developed and proposed for approval.

TIMELINE AND MEETING TOPICS

Between December 2017 and January 2019, GPI and CEE convened a total of seven meetings, each covering the topics listed below. Meetings were held in-person in various locations in Minneapolis and St. Paul. Most meetings also allowed remote attendance when possible.

Meeting 1: Introduction to Demand Response

- Presentations:
  - Demand response 101 (Xcel Energy, The Brattle Group)
  - Regional transmission organizations and demand response (MISO)
  - Current utility demand response programs in Minnesota (Xcel Energy, Great River Energy)
- Discussion:
  - New demand response technologies and opportunities

Meeting 2: Demand response technologies and programs

- Presentations:
  - Current utility demand response programs in Minnesota (Otter Tail Power)
  - What XcelEnergy is currently exploring for new DR technologies and programs
- Discussions:
  - Q&A with MISO staff
  - Panel on DR technologies and programs, including enabling technologies, examples from other utility markets, and DR aggregators

Meeting 3: Demand response values, benefits, and challenges (April 2018)

- Presentation:
  - Demand response values and benefits (Xcel Energy)
- Discussions:
  - Stakeholder panel on demand response benefits and challenges (MN Department of Commerce, Citizens Utility Board, Fresh Energy)
  - What are stakeholders' objectives for Xcel Energy's additional DR offerings?

Meeting 4: Demand response cost-effectiveness; stakeholder guidance (May 2018)

- Presentation:
  - Evaluating demand response cost-effectiveness in resource planning (Xcel Energy)
- Discussion:

  - What are stakeholders' design principles for Xcel Energy's additional DR offerings? (continued from Meeting 3)

Meeting 5: Demand response potential; distribution geo-targeting (August 2018)

- Presentations:
  - Demand response potential study preliminary results (The Brattle Group)
  - Demand response geo-targeting on the distribution system (Center for Energy and Environment)
- Discussion:
  - Exploring the preliminary results of the most recent demand response potential study

Meeting 6: Xcel Energy's draft demand response portfolio (August 2018)

- Presentation:
  - Draft portfolio of additional demand response offerings (Xcel Energy)
- Discussion:
  - Stakeholder feedback on Xcel Energy's draft portfolio

Meeting 7: Xcel Energy's proposed demand response programs (January 2019)

- Presentation:
  - Demand response potential study final results (The Brattle Group)
  - Proposed list of new and expanded demand response offerings (Xcel Energy)
  - Recommendations from Advanced Energy Management Alliance and Xcel Large Industrials to enable Xcel to achieve the Commission's mandate for incremental demand response in its service territory.
- Discussion:
  - Q&A on the final demand response potential study
  - Stakeholder feedback on Xcel Energy's new and expanded demand response offerings

PARTICIPATING ORGANIZATIONS

Meetings in this process were open to the public and noticed in MN PUC Docket No. E-002/RP-15-21. GPI also sent email invitations to a distribution list of parties that had expressed interest in Xcel Energy's demand response programs.

Meetings drew an average attendance of 30-40 individuals per meeting. GPI, CEE, and Xcel Energy would like to thank the following organizations for their participation in one or more (and in many cases, all) of the seven meetings. As noted above, comments summarized in this document represent the collective insights of stakeholders who attended these meetings and should not be attributed to any specific organization or individual.

- MISO
- Advanced Energy Management Alliance
- Center for Energy and Environment
- Citizens Utility Board of Minnesota
- Fresh Energy
- Great River Energy
- Landis+Gyr
- LLS Resources, LLC
- Minnesota Department of Commerce
- Minnesota Municipal Utilities Association
- Minnesota Pollution Control Agency
- Minnesota Power
- Minnesota Public Utilities Commission
- MN Attorney General's Office
- MN Department of Commerce
- MN Pollution Control Agency
- NRG Curtailment Solutions, Inc.
- Otter Tail Power Company
- Rakon Energy LLC
- Stoel Rives, on behalf of the Xcel Large Industrials
- Strategen Consulting
- The Brattle Group
- The Mendota Group, LLC

MEETING MATERIALS

All meeting materials from this process, including agendas, slide decks, resources, documents developed for the group, and meeting notes are available online at https://trello.com/b/vqrVwhQ3/xcel-energy-demand-response-workgroup.

III. Design Principles and Filing Objectives

Demand response is a complex and wide-ranging topic. Demand response programs can be designed to offer services at the distribution and wholesale market level, engage every type of customer, and relate to or overlap with other program offerings including energy efficiency and time-varying rates. Given this complexity and the fact that Xcel Energy's demand response programs were still in development at the time these stakeholder convenings took place, GPI and CEE asked stakeholders to collaborate in developing a set of consensus-based principles that could provide guidance to any new or expanded demand response offering, allowing flexibility on behalf of Xcel Energy to design programs in consideration of the parameters set by stakeholders.

Stakeholders participating in this process developed two lists—Design Principles and Filing Objectives. The Design Principles provide guidance for designing demand response programs or portfolios of programs. The Filing Objectives describe what information stakeholders would like to see when new demand response offerings are presented for consideration to the appropriate regulatory body (the Minnesota Public Utilities Commission and/or the Minnesota Department of Commerce). These two lists are interrelated and therefore intended to be taken as a package. In other words, while all stakeholders may not have supported each of these objectives or principles on their own, they found the full set acceptable.

Importantly, these are meant to be general guidelines and not absolute requirements. Just because an offering arguably complies with these does not guarantee that stakeholders will approve of it. These simply offer a starting point for developing demand response offerings that have a higher likelihood of earning stakeholder approval in the regulatory process.

DESIGN PRINCIPLES

What would stakeholders like to see from a demand response portfolio of any size from Xcel Energy in Minnesota?

1. **Compensate demand response appropriately given the specific benefits it provides.**

   Incentives and penalties should be informed by the underlying benefits and value streams that the program is intended to achieve. It's up to the utility to find the right incentive levels that will both elicit customer action and enable the desired benefits at a lower cost than other resource options.

2. **Ensure pricing and expectations are clear, concise, and transparent for customers.**

   The utility should make efforts to ensure that customers participating in DR programs understand the program rules.

3. **Provide flexibility and options for customers.**

   Demand response programs are ultimately made possible as a result of cooperation from customers. Therefore, it's important that the utility provides offerings that allow flexibility and options for customers with different needs, while also delivering the desired system benefits.

FILING OBJECTIVES:

What would need to be true to earn stakeholder support when new or expanded demand response offerings are filed with the Commission?

1. **Be clear about the outcomes that demand response offerings are designed to achieve, and how those should be measured down the road.**

   Outcomes addressed should include cost-effectiveness, customer engagement as participation, system reliability and flexibility, carbon reduction, resource integration, and avoidance of building new assets.

2. **Fully evaluate demand response program costs and benefits.**

   Costs and benefits should be evaluated from the perspective of multiple key actors affected by demand response programs, including the utility, DR participants, ratepayers who are not DR participants, and society at-large (e.g., including public policy related impacts such as greenhouse gas emissions). This evaluation should include consideration of alternatives to achieving the same benefits (e.g., if DR is being used to address a system need, how do DR costs and benefits compare to those of whatever alternative might be used to meet that system need?).

Demand response programs can deliver several benefits, including the following: reducing peak loads; shifting loads from high-cost times to low-cost ones; shifting loads from periods with high greenhouse gas emissions to periods with lower emissions; beneficially adding new loads with attention to costs and emissions; reducing energy and capacity costs; and reducing the costs of necessary ancillary services including frequency regulation, spinning reserves, and supplement reserves. DR programs can achieve higher levels of cost effectiveness by ensuring that programs are enabling as many benefits as possible.

The costs and benefits being evaluated may depend on the particular regulatory pathway through which a new demand response program is proposed (e.g., programs being proposed as CIP offerings may be evaluated differently than those being proposed through a miscellaneous filing).

At least one stakeholder felt that the MISO capacity auction does not provide an accurate price signal for determining the cost-effectiveness of DR offerings and that the MISO-calculated CONE (cost of new entry) should be used as a proxy. Xcel Energy staff responded that DR offerings would need to compete with the company's individual CONE, which is being updated for the upcoming IRP and is expected to be lower than the MISO value due to the availability of many brownfield sites (as opposed to more expense greenfield sites) for new CT's.[1]

3. **Address reliability and resilience of demand response offerings, as relevant.**

   Demand response proposals should include evidence to show how the proposed offerings will reliably deliver the intended benefits. This evidence could include physical testing, the deployment of incentives and penalties that can arguably elicit a response from customers, and audits to confirm that a program is reliably delivering its intended benefits when called upon. In cases of entirely new offerings where showing evidence of costs and benefits may not be possible, pilot projects could be deployed to develop the needed evidence.

4. **Delineate between dispatchable and non-dispatchable demand response.**

   The group discussed the difference between "dispatchable" and "non-dispatchable" DR, but did not come to consensus on exact definitions for those terms. In general, this objectives asks Xcel Energy to differentiate between something like a time-of-use rate, which could be considered a DR offering but is arguably not dispatchable (i.e., it can't be called upon to reduce load in an emergency event), and something like critical peak pricing, which is arguably dispatchable to reduce load when needed. Some stakeholders questioned the extent to which non-dispatchable offerings qualify as demand response.

[1] Meeting 4 Notes, pages 3-4, available online at https://trello.com/c/aNqqmBv4/4-meeting-4-dr-design-principles-objectives-and-cost-effectiveness-5-1-2018

In addition, some stakeholders asked that Xcel Energy clarify which demand response offerings, and how much of those offerings, are accredited in MISO.

5. **Show transparency towards meeting the objectives listed above.**

   For all of the filing objectives above, Xcel Energy is more likely to earn support from stakeholders by showing or explaining its efforts to meet these objectives as transparently as possible.

6. **Consideration of the AEMA/XLI Recommendations**

   The Advanced Energy Management Alliance (AEMA), which represents the interests of demand response service providers, including aggregators and the end-use consumers who ultimately provide demand response resources, was one of the organizations that provided dedicated stakeholder participation to this process. AEMA partnered with Xcel Large Industrials (XLI), a group of Xcel's largest industrial customers who are represented in regulatory matters by the law firm Stoel Rives LLP, to develop a set of recommendations for what they would like to see reflected in Xcel Energy's DR offerings based on discussions during this process.

   GPI and CEE, at the request of AEMA and XLI and with consent from Xcel Energy, distributed a document listing those recommendations in advance of the seventh meeting. Facilitators also allowed AEMA and XLI to present their recommendations to the group at that meeting.[2]

   Most of the best practices that AEMA and XLI recommended were in alignment with the group's previously developed Design Principles and Filing Objectives, though their recommendations offered much more specific detail. The one best practice area that differed most notably from the group's Design Principles and Filing Objectives was in regard to the utility's use of third-party DR service providers.[3] AEMA and XLI argue in their written proposal that demand response aggregators can offer services that benefit both customers and the utility, ultimately making DR programs more effective. [4]

   The appropriate use of third parties to support Xcel Energy's demand response efforts was a theme that arose in several discussions throughout the stakeholder engagement process. and may be worth considering when new or expanded demand response offerings are proposed for approval.

[2] The recommendations document and associated slide deck from AEMA and XLI are available online at https://trello.com/c/qvtlayfB/23-meeting-7-wrap-up-1-22-2019

[3] AEMA proposals mirror the "Indiana Model" for consumer and aggregator participation in DR programs. Under the Indiana model, aggregators act as an intermediary between the utility and the customer, bringing the customer's load drop capabilities to the utility, and the utility will then, if appropriate, register the load drop capabilities with the ISO. Under this approach, there is no infringement on the state's prior decisions under FERC order 719

[4] Recommendations document at 3

IV. Demand Response Potential Study

BACKGROUND ON THE STUDY

To support both its own efforts to comply with the commission's requirement and stakeholder discussions under this process, Xcel Energy hired The Brattle Group to conduct a study of demand response potential in its Northern States Power (NSP) service territory.

The Brattle Group had conducted a previous study in 2014 that looked only at DR technical potential, which was the basis for the Commission's requirement. This more recent study looked beyond that technical potential, evaluating both cost-effective potential—in which demand response program costs, equipment costs, and incentives must outweigh avoided resource costs—and achievable potential, which estimated program enrollment rates based on local and national market research.

This new study sought 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," including mid-point analyses at the year 2023, which was the deadline for procuring 400 MW of additional DR as required by the Commission, and the year 2025, which was the commission's deadline for evaluating the cost-effective achievability of 1,000 MW of additional DR.[5]

The study included two scenarios for evaluating DR deployment under different sets of assumptions – a Base Case and a High Sensitivity Case. The study states, "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."

By comparison, "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."[6] Importantly, the study notes that the High Sensitivity 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."[7]

[5] Ryan Hledik et al., *The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory,* (The Brattle Group, January 2019), i, available online at https://trello.com/c/qvtlayfB/23-meeting-7-wrap-up-1-22-2019

[6] Ibid, iv

[7] Ibid, iv

INTERPRETING THE COMMISSION'S REQUIREMENT

Importantly, the study lists two clarifications around interpreting the commission's 400 MW requirement. The first is that there are three ways to measure demand response – at the capacity level, the generator level, and the meter level:

> 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.[8]

The report then states that while "NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR," the report itself assesses the commission's "procurement requirement as a 391 MW generator-level value unless otherwise specified."[9] To be consistent, this section of the stakeholder process summary uses demand response capability values that align to the report's 391 MW generator-level interpretation of the commission's 400 MW requirement.

The second clarification is that the requirement set by the commission was established based the 2014 potential study, when Xcel Energy had 918 MW of demand response capability. Much of this newer study looks at incremental DR potential from a lower 2018 baseline of 850 MW of DR capability. This reduction in the baseline is due to program right-sizing that took place after 2014, in which customers on interruptible tariffs were tested to check their ability to comply with the requirements of those tariffs and subsequently removed from the tariffs if warranted.[10]

The effect of this baseline change from 2014 to 2018 is that in order to meet the commission's requirement, Xcel Energy must procure an additional 459 MW of generator-level DR from the 2018 baseline, adding up to a total generator-level demand response capability of 1,309 MW by 2023.

RESULTS AND STAKEHOLDER DISCUSSION

With regard to the commission's 2023 requirement, the study concluded that under the Base Case assumptions Xcel Energy could cost-effectively deploy 306 MW of additional generator-level demand response by 2023 from a 2018 baseline, falling short of the Commission's 459 MW requirement (adjusted from the original 400 MW value as noted above). This was partly due

[8] Ibid, 17

[9] Ibid, 17

[10] Ibid, 18

to the assumption that advanced metering infrastructure (AMI) would not be fully deployed in 2023, an item that was of interest to stakeholders and is described in more detail below.

Beyond the 2023 deadline, the study found that, under the Base Case assumptions and with full AMI deployment in 2024, Xcel Energy could deploy "1,243 MW of cost-effective DR potential in 2025."[11] This quantity would be close to, but still short of, the incremental 459 MW (1,309 MW total potential) requirement for 2023. Looking out to 2030, the Base Case assumptions yielded 468 MW of incremental cost-effective DR, adding up to a total portfolio 1,318 MW.[12]

Staff from The Brattle Group presented preliminary results from the study at Meeting 5 and final results at Meeting 7. While the opportunity to discuss the study during meetings was clearly valuable to stakeholders, it seemed to facilitators that more time could have been useful to understand the study results in-depth. To support ongoing conversation and complement the information contained in the study, we have described below the topics that appeared to be of most interest to stakeholders during Meetings 5 and 7, including examples of specific issues or questions that were raised.

Avoided capacity costs

In order for demand response to be cost effective in the study, the sum of its program, equipment, and customer incentive costs would have to outweigh the cost of an avoided resource. Therefore, the assumed cost of an avoided resource was of particular interest to stakeholders because it serves as a threshold that demand response must pass to be considered cost effective.

As noted above under Filing Objective 2, Xcel Energy's cost of a new natural gas generation resource is significantly lower than national averages due to the availability of brownfield sites that reduce development costs for new turbines. This was a concern for some stakeholders. The study addresses this difference by looking at demand response potential under two different avoided capacity costs: Xcel Energy's assumed cost in its 2018 integrated resource plan of $64/kW-yr for the base case, and the U.S. Energy Information Administration's 2018 Annual Energy Outlook assumed cost of $93/kW-yr for the high sensitivity case.[13]

Cost-benefit analysis

In alignment with Filing Objective 2, many stakeholders wanted to better understand how the costs and benefits of demand response were analyzed in the study, in comparison to traditional forms of generation such as natural gas plants. In particular, some participants were interested in the assumptions around the operational constraints of

[11] Ibid, iii

[12] Ibid, iv

[13] Ibid, 13

demand response programs (e.g., the ability to actually elicit the required response from customers when needed, with attention to the necessary frequency and duration of that response).

Staff from The Brattle Group responded that they analyzed demand response costs and benefits by taking Xcel Energy's assumed cost of providing capacity through traditional generation (e.g., $63/kW-yr in the base case) and allocated that cost across the 100 hours of the year when electricity demand was most likely to be at its peak. This takes the annual avoided capacity cost and turns it into an hourly capacity cost that demand response must beat to be cost-effective in each of those hours. The Brattle Group's model then attempts to dispatch demand response in those hours instead of traditional generation, accounting for DR costs, operational constraints such as the inability to use air conditioning demand response programs in winter and additional values, such as deferral of transmission and distribution investments. Additional details of the cost benefit analysis are included in the study.

Incentive levels for existing program participants

One key clarification that arose through stakeholder discussion was that the study looked only at the costs to acquire *new* demand response program participants, either through entirely new programs or through the acquisition of new participants for existing programs. However, the study did not look at adjusting incentive levels or changing program designs for existing DR participants. Some stakeholders were concerned that so doing may have excluded potentially significant additional capacity of cost-effective DR and certainly excluded analysis of existing customer capacity beyond emergency-only interruptions. While any changes for existing program participants were outside the scope of this study, this issue may be worth considering as changes to existing demand response programs are proposed in the future.

Advanced metering infrastructure

Stakeholders were interested in how advanced metering infrastructure (AMI) was included in the potential study because it's a foundational technology that enables several demand response programs, including time-varying rates and critical peak pricing. With no residential advanced metering infrastructure currently deployed or planned other than for the residential time-of-use pilot that will commence in 2020, the study assumed that NSP would not achieve full AMI deployment until 2024. This was a factor in the study's finding that Xcel Energy could not cost-effectively achieve 459 MW of additional demand response by 2023 from a 2018 baseline.

Participants were also interested in assumptions around the costs of AMI. One of the challenges with addressing those costs is that AMI can be used to support many programs and services, demand response being only one of them, so it is difficult to assign a portion of the total investment in AMI to demand response programs alone. The Brattle Group staff explained that while AMI was assumed beginning in 2024, its costs were not included in the assessment of DR program costs.

The impact of this on the study is that programs that rely on AMI after 2024 may appear more cost effective than if a portion of the investment in AMI was included in their costs. Some stakeholders were interested in further discussing AMI investment costs, but acknowledged that such a discussion might be better suited to a conversation outside of these demand response-specific meetings.

Transition from Saver's Switch to smart thermostats

In both Meeting 5 and Meeting 7, stakeholders were curious to know more about a shift that the study predicted between 2017 and 2023, in which current participants in the Saver's Switch program leave to become participants in smart thermostat programs. The Brattle Group staff explained that utility-controllable smart thermostats offer more sophisticated demand response controls over Saver's Switch, such as the ability to pre-cool spaces and coast through an event, rather than simply cycling A/C units during the event. Further, since the two programs control the same devices (i.e., A/C units), customers may not participate in both.

This transition between the two different technologies leads to a net increase of 114MW of demand response—roughly one third of the cost-effective demand response capacity that could be deployed before 2023.[14] The Brattle Group staff also noted that while these programs are offered to residential, commercial, and industrial customers, most of the increase is due to residential customers buying smart thermostats.

Full consideration of value streams, including ancillary services

Participants were interested in finding out whether and how DR value streams beyond avoided capacity were analyzed, including transmission and distribution deferral and ancillary services such as frequency regulation. Staff from The Brattle Group explained that up to 2023, most of the value attributed to demand response comes from deferred capacity investments. However, the study's High Sensitivity Case looks at the value of additional benefits from ancillary services towards 2030, including a doubling of the need for frequency regulation as well as additional need for transmission and distribution deferral. Staff from The Brattle Group clarified that frequency regulation is the only ancillary service that was modeled because it provides the greatest value to demand response.

Full consideration of newer demand response programs

The Brattle Group's study considered eight new demand response program options, but found that only smart water heating could cost-effectively be deployed before 2023.[15] Some stakeholders were interested in knowing more details about how these newer programs were considered. In particular, participants asked about behavioral demand response (in which customers receive non-monetary positive feedback for reducing their electricity usage in response to a notice) and heat pump space and water heating.

For behavioral demand response, which was not found to be cost effective under any of the cases modeled, The Brattle Group staff explained that they looked at studies and

[14] This value was initially presented as 105 MW in Meeting 5 (Brattle deck slide 11) and was later updated to 114 MW in the final version of the potential study.

[15] Hledik et al., Potential for Load Flexibility, 19-21

spoke with O-Power, a behavioral demand response service provider, to better understand the per-customer costs of running those programs. For heat pump space and water heating, the research team explained that they considered it, but didn't include it in the study for two reasons: first, that most of the benefits are efficiency rather than demand response; and second, that penetration of electric heat pumps is currently too low to warrant its inclusion, though that could change in the future. However, the study does include electric resistance water heaters, which currently have a more substantial market penetration.

V. Xcel Energy's Demand Response Offerings in Development

At the sixth stakeholder meeting in August 2018, Xcel Energy presented for feedback an initial list of demand response programs under development to meet the commission's requirement. This included eight residential DR programs, five programs for large commercial and industrial customers, and six programs for small/medium commercial and industrial customers.

INITIAL FEEDBACK

In response to the offerings presented at Meeting 6, stakeholders said that the list of programs seemed to strike a balance between traditional DR and forward-looking, innovative programs. They also said that Xcel Energy seemed to be looking at the right general buckets of opportunities. However, several stakeholders stated that they would need much more detail to be able to fully evaluate Xcel Energy's DR offerings. Below, we have summarized the general requests for more information that were raised during Meeting 6:

Contribution to Commission Requirement

The programs presented at Meeting 6 did not include estimated DR capabilities in terms of megawatts, so some stakeholders wanted to know how each program would contribute to the commission's requirement. As noted below, Xcel Energy provided initial estimates for these numbers in Meeting 7.

Cost-Effectiveness and Potential Study

Stakeholders desired to know more about the cost-effectiveness of each program being developed, and how that cost-effectiveness was derived, whether based on sensitivities in The Brattle Group's potential study or through another method. Some parties wanted additional information about how cost-effectiveness of DR programs would be represented in the forthcoming integrated resource plan. It was also noted that cost-effectiveness is determined differently depending on the regulatory process being used to seek program approval – another piece of information that stakeholders desired and is described further below.

Regulatory Process

Some stakeholders wanted more information about which regulatory process(es) would be used to seek approval for each DR program. Accordingly, parties were interested in cost-effectiveness tests (as notes above) depending on the regulatory vehicle being used as well as how measurement, verification, and reporting protocols would be executed.

Advanced Metering Infrastructure (AMI)

Stakeholders had several questions about advanced metering infrastructure in relation to new demand response offerings, including how AMI deployment would impact the timing and pricing of each offering and whether these offerings would be used to justify investment in AMI.

Alignment with Filing Objectives and Design Principles

Some stakeholders wanted more information about whether and how each program aligned with the group's Filing Objectives and Design Principles. In particular, some participants at Meeting 6 were concerned that the programs seemed fragmented, potentially limiting customer choice and compensation for flexibility. There was also a question raised about which programs are dispatchable (i.e., in the utility's control) versus those that affect load shape but cannot be actively controlled by the utility, such as time-varying rates.

Opportunities for Aggregators

Some parties wanted to know more about the role of aggregators in the various programs that were presented, including whether and how aggregators could participate.

Consolidating Offerings

Some participants recommended combining several of the different C&I demand response offerings into a single program to encourage broad participation and avoid competition between similar offerings.

REQUEST FOR A DETAILED TABLE OF OFFERINGS

At the conclusion of Meeting 6, there seemed to be general agreement among the group that a more detailed presentation of Xcel Energy's new DR programs under development would be helpful to aid with understanding and evaluating the offerings, both individually and as a total package. Several stakeholders suggested that Xcel Energy come back to the group with a table listing the various offerings, their alignment with the Filing Objectives and Design Principles, and responses to the pieces of information requested above.

In response, Xcel Energy staff offered to develop the table and provide as much information as they could, based on availability of that information and timing constraints. Xcel Energy staff presented the table for review at the seventh and final meeting in January 2019. Below, we have listed the specific items that stakeholders asked Xcel Energy to provide and a summary of the information that was available in response. We have also included a summarized version of the table itself.[16] Since these items were of interest to stakeholders during these meetings, it's likely that they'll be of interest as program move through the regulatory approval process.

1. **Provide a name and short description of the offering**

   The table listed 20 individual demand response offerings under development, each with a short description.

2. **Provide a narrative explaining how it complies with the group's Filing Objectives and Design Principles.**

   The table included columns that respond to many of the Design Principles and Filing Objectives, though some of the information was not yet available.

3. **What is its contribution to meet the commission's requirement?**

   The table listed estimated DR capability values in megawatts for each program area based on the Brattle Group's potential study, adding up to a total of 271 MW. The values were representative of the incremental load available when DR programs are offered simultaneously as part of an overall portfolio, and therefore were provided by program type rather than for each specific program. Xcel Energy noted that these were initial placeholders and would fluctuate as programs are further developed.

4. **Is it expected to be cost effective?**

   There are two cost-effectiveness columns – one based on whether the program was deemed cost effective based on avoided capacity costs; the other is based on an additional a cost-benefit analysis that was not yet available.

5. **Is it dispatchable or non-dispatchable?**

   This was included for each offering.

6. **Does it utilize AMI (to help justify the cost of investing in AMI)?**

   This information was not yet available.

7. **Does it have energy efficiency benefits?**

   This was included for each offering.

8. **What evidence is there of customer interest in the program?**

   This information was not yet available.

9. **What regulatory process(es) will be used to seek approval, and are there specific conflicts or risks anticipated?**

   This information was available for some of the programs and unavailable for others.

10. **What role, if any, is there for demand response aggregators?**

[16] The full table is available online in both PDF and Microsoft Excel formats at https://trello.com/c/qvtlayfB/23-meeting-7-wrap-up-1-22-2019

In the table presented, one of the programs—interruptible offerings for medium and small C&I customers—was targeted for third-party aggregators.

Feedback in response to the table at Meeting 7 was limited and will need to be refined as individual offerings move through the regulatory process. Overall, stakeholders said that they thought Xcel Energy was taking a thoughtful approach to a variety of achievable programs, and that the portfolio seemed forward-thinking from the perspective of supporting resource integration in the future. Some participants inquired whether the programs could be combined into more streamlined customer offerings. Xcel Energy staff responded that streamlining would take place once the company's full demand response roadmap was complete.

Participants also had the following questions in response to the table. While these were not resolved in the meeting, they may be worth pursuing in the formal regulatory process for considering Xcel Energy's DR offerings:

- Would it make a difference to consider incremental demand response from *existing* participants, since The Brattle Group's report looked only at potential for new participants?
- What will the carbon reduction impacts be from these programs?
- How might activity at MISO affect these programs?

Table 1. Summarized Version of Xcel Energy's Demand Response Offerings in Development as of January 22, 2019

Program Type	Est. Potential (MW)	Segment	Product	Description	Est. Potential Achievement Date
Behavioral DR	-	Residential	"Hands-off" DR	Use messaging without technology to encourage DR event participation	2023
Commercial Building Controls	10	C&I, Medium	Commercial Building	Leverage EMS software to provide DR capacity & overall demand mgmt	2021
Critical Peak Pricing	41	C&I, Medium	Critical Peak Pricing (Opt-in)	Base periods are similar to TOU structure with lower energy/demand prices, but during "critical" periods customer pays higher pricing	2022
Electric Vehicles	<1	Residential	Electric Vehicle Smart Charging	MN residential smart charging pilot with L2 EVSE, proves out EE and peak load shifting, may include economic demand response	2020
			Electric Vehicles DR& Storage	Use EV's for DR and storage opportunities	2024
Interruptible Offerings	79	C&I, Medium, Small	Peak Partner Rewards	Customer receives incentives for nominated capacity and/or performance during DR events	2020
		C&I, Medium, Small	Third-Party Aggregation	Allow third-party aggregator to promote, recruit and enroll customers into DR program.	2021
		C&I, Medium	Interruptible Rates	Rate discount or credit for agreeing to reduce load during specified periods (updates to current program)	2022
Other (not included in Brattle Group potential study)	-	C&I	DERs for Ancillary Services	Use DERs to provide ancillary services	2021
		C&I	Leverage Microgrids	Leverage existing or planned microgrids for DR capacity	2022
		All	Geo-targeted Distribution	Identify stress points in distribution system & target affected customers with regular or enhanced DR offers	2019 - CEE
		TBD	Reverse DR Balance system	Load for excess renewable generation by incentivizing customers to use energy at these times	2023
		Residential	BTM Batteries/Storage	Deploy battery technology behind customer meters for DR and load capacity	2024
Smart Thermostats	112	Residential	Expand current smart thermostat program	Expand current ST offerings into other markets, existing programs, or gas DR	2021
			Home Energy Management (HEM)	Provide technology to customers that helps reduce energy usage, educates, and facilitates DR	2024
			Smart Thermostat Optimization	Deploy software to manage & optimize smart thermostat operations to improve energy savings, demand reductions, etc.	2020
Smart Water Heating	8	Residential	Water Heaters for DR	Leverage water heaters for DR capacity	2023
			Water Heaters DR using CEA-2045 connection/technology	Via a controlled demonstration, this project will provide economic justification and a plan for a market transformation	2023
Thermal Storage	-	C&I	Thermal Storage	Leverage things like refrigeration as storage devices to shift demand	2023
Updating Saver's Switch	21	Residential, Small C&I	Saver's Switch (2-way communicating)	Updating our current technology and expanding the program	2021

VI. Conclusion and Next Steps

In compliance with the Commission's requirement to procure an additional 400 MW of demand response, Xcel Energy is in the process of reviewing roughly 20 expanded and new DR program offerings in its NSP service territory.

Those offerings are based in part on a study that Xcel Energy hired The Brattle Group to conduct to identify the potential for cost-effective, incremental DR programs, which found that the company could meet some, but not all, of the Commission's required demand response capability cost-effectively by 2023. This finding was due to a series of factors, including low capacity prices, lack of advanced metering infrastructure to enable some programs, low development costs for new generation assets, and limited benefits from ancillary services and transmission and distribution deferral.

There are multiple next steps for Xcel Energy's demand response offerings for Minnesota. The portfolio as a whole will be considered in Xcel Energy's next Integrated Resource Plan filing, with an assumption of deploying enough DR to meet the Commission's requirement by 2023 for at least one of the plan options. The individual demand response programs that will be deployed to achieve that requirement are currently in development and will be brought forth for regulatory approval, though the exact details of regulatory consideration were not available at the time of these stakeholder meetings.

As those offerings are determined to move forward, the Design Principles and Filing Objectives that were collaboratively developed by stakeholders as part of this process offer a useful framework, both for providing ongoing guidance to the design of those offerings, and for evaluating them once they are finalized and submitted for regulatory consideration. To the extent that program offerings can be designed and filed in accordance with the stakeholder guidance captured in this report, they will have a higher likelihood of earning stakeholder support.

APPENDIX H – ENVIRONMENTAL REGULATIONS REVIEW

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I. GREENHOUSE GASES

A. Regulation of CO_2 from Existing Power Plants

1. Clean Power Plan

The U.S. Environmental Protection Agency (EPA) in October 2015 promulgated, under Section 111(d) of the Clean Air Act, a final rule *Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Utility Generating Units*, termed the "Clean Power Plan" (CPP).[1] At the time of our last Upper Midwest Resource Plan, the rule was final and some of our states were beginning to develop implementation plans. We discussed in that Plan how the expected CO_2 reductions under our Preferred Plan would position Xcel Energy for compliance with the CPP, under various assumptions about how our states might design their plans and allocate CO_2 allowances.

Several states and industry petitioners, led by West Virginia, filed suit at the D.C. Circuit Court to stay the CPP. The D.C. Circuit initially declined to stay the rule, but the U.S. Supreme Court stepped in and stayed implementation of the CPP in February 2016. In the interim, the D.C. Circuit Court has held the case in abeyance.

EPA estimated that at the national level, the CPP would have reduced electric sector CO_2 emissions by about 32% below 2005 levels by 2030. Xcel Energy has already exceeded this reduction, achieving approximately 34% below 2005 levels as of 2018 for our Upper Midwest system. Our Preferred Plan would take us beyond 80% below 2005 levels by 2030.

2. Affordable Clean Energy rule

EPA in October 2017 issued a proposed rule to repeal the CPP, based on its view that the CPP exceeds the EPA's statutory authority under the Clean Air Act.[2] EPA also published an Advanced Notice of Proposed Rulemaking seeking comment on whether to develop a replacement rule, and what form such a rule should take.[3] In August 2018, EPA then issued a proposed CPP replacement rule, *Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units*, termed the "Affordable Clean Energy" (ACE) rule.[4] The proposed rule applies to coal-fired steam electricity generating units in operation on or before January 8, 2014.

[1] 80 *Fed. Reg.* 64,662, October 23, 2015.
[2] 82 *Fed. Reg.* 48,035, October 16, 2017.
[3] 82 *Fed. Reg.* 61,507, December 28, 2017.
[4] 83 *Fed. Reg.* 44,746, August 31, 2018.

Whereas the CPP defined the Best System of Emission Reduction (BSER) to encompass CO_2 reductions achievable throughout the electricity system – including efficiency improvements at coal units themselves, switching from coal to gas, and renewable energy additions – the ACE proposal replaced this interpretation with a much narrower "inside the fence line" approach based only on heat rate improvements (HRI) implemented at the affected coal units. The proposal would require states to make unit-specific determinations of the achievable emissions reductions through HRI, expressed as an allowable emissions rate (lbs CO_2/MWh gross), and to evaluate eight "candidate technologies" for HRI: neural network/intelligent sootblowers, boiler feed pumps, air heater and duct leakage control, variable frequency drives, blade path upgrades for steam turbines, redesign/replace economizer, and improved operating and maintenance practices. EPA did not propose any BSER for existing natural gas-fired turbines, finding that available emissions reductions would be expensive or would likely provide only small reductions.

The proposed rule gives states limited flexibility in making these determinations. They may consider remaining useful life of a unit, which may result in the application of a less stringent standard of performance or later compliance date; may accept non-BSER measures, but only if implemented at the unit itself; and may allow averaging among units at a single power plant, but not across plants. States would not be allowed to average or trade across affected units, nor between affected units and non-affected sources such as wind or solar generation. As such, the proposed rule would not allow consideration of emission reductions achievable through measures such as renewable energy, energy efficiency, increasing natural gas generation, retiring or reducing operation of coal units.

3. *Affordable Clean Energy Rule as Finalized*

On June 19, 2019, EPA published a final ACE rule. Because of its release so near the filing of this Resource Plan, we are still reviewing the rule and, to the extent there are substantive differences between the proposed and final rule that impact our Preferred Plan, we offer to supplement the record. However, we include a preliminary review here.

The ACE rule finalizes EPA's repeal of the CPP, which EPA maintains exceeded EPA's statutory authority because EPA took an overly expansive view of section 111(d) and endeavored to reduce emissions by shifting the balance of coal, gas and renewable generation across the power grid rather than focusing only on measures implemented at the affected coal units.[5]

As in the proposed rule, EPA defines the BSER as only including measures implemented at the affected coal-fired units. The rule does not allow state plans to set carbon reduction targets based on renewable energy development, shifting from coal to gas, or averaging or trading across units – strategies the CPP relied on to drive the bulk of its emission reductions – but rather maintains the list of eight approved HRI measures states may consider in establishing unit-specific performance standards. It grants states discretion to determine which of those projects to require at the affected units and, following the statutory text, allows states to take into account the remaining useful life of the source and other factors, including the cost reasonableness of requiring HRI on units with a limited remaining useful life.

The final rule allows states three years from the date that it is published in the Federal Register to finalize plans and submit their own implementing rules. Compliance is then required two years thereafter, although states have discretion to extend that compliance deadline based on specific factors at the regulated units. Based on this timeline, we believe compliance could be required around 2024, not including possible delays due to litigation of the final rule.

4. Relevance to Xcel Energy

Xcel Energy submitted comments on the proposed ACE rule, arguing the Clean Air Act allows EPA to provide states much greater flexibility to reduce CO_2 through a range of actions throughout the electric system, and that granting such flexibility would result in more cost-effective and greater CO_2 reductions. However EPA retained its narrow, "inside the fence line" approach.

Under the rule as finalized – and absent our plans for early retirement of all remaining Upper Midwest coal units under the last Resource Plan and the current Preferred Plan – we expect that HRI could be required on coal-fired units that continue to operate. However, section 111(d)(1) explicitly requires, and EPA emphasizes, that EPA must "permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies."[6] Further, the proposed rule specifies that consideration of remaining useful life would allow a state's plan to establish tailored compliance deadlines specific to each source; consider "changes in the operation of the units, among other factors the state believes

[5] EPA Fact Sheet, *Repeal of the Clean Power Plan*. June 19, 2019.
[6] ACE rule, 83 Fed. Reg. 44,749 (August 31, 2018).

are relevant";[7] consider "unreasonable cost of control resulting from plant age"; consider factors that "make application of a less stringent standard or final compliance time significantly more reasonable"; and consider "factors that influence decisions to invest in technologies to meet a potential performance standard [including] timing considerations like expected life of the source, payback period for investments, the timing of regulatory requirements, and other unit-specific criteria."[8]

The final rule also emphasizes this discretion:

> It will be up to the states to, either directly or indirectly, take cost into consideration in establishing unit-specific standards of performance. CAA section 111(d) explicitly allows the states to take into consideration, among other factors, the remaining useful life of the existing source in applying the standard of performance. For example, a state may find that an HRI technology is applicable for an affected coal-fired EGU but find that the costs are not reasonable when consideration is given to the timeframe for the planned retirement of the source (i.e., the source's remaining useful life).[9]

At this point, it is too early to predict exactly how Minnesota's ACE plan[10] will treat the units that the company is proposing to retire in our Preferred Plan. Minnesota's implementation of the ACE rule will depend on the outcome of inevitable litigation over the rule as well as the state plan development process, which will be in the hands of the Pollution Control Agency (PCA). Based on the factors set forth above, however, we believe that PCA could avoid requiring the installation of HRI on the company's coal units by incorporating the proposed unit retirement dates into the Minnesota ACE plan. Requiring HRI on units with only a few years of life remaining would necessitate a very short payback period, imposing accelerated depreciation of HRI investments and an unreasonable cost of control. We believe that, following the statutory language of Section 111(d)(1), EPA would be likely to approve such a plan. The company will continue to evaluate the implications of the ACE rule and work with PCA to harmonize the Minnesota ACE plan with the Preferred Plan in a manner that minimizes the cost of the ACE rule to customers.

B. Regulation of CO_2 from New, Modified and Reconstructed Power Plants

1. Standards of Performance for New, Modified and Reconstructed Stationary Sources

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[7] 83 Fed. Reg. 44,763.
[8] 83 Fed. Reg. 44,766.
[9] EPA "Affordable Clean Energy" final rule, pre-publication version, at page 81. *Repeal of the Clean Power Plan; Emission Guidelines for Greenhouse Gas Emissions from Existing Electric Utility Generating Units; Revisions to Emission Guidelines Implementing Regulations*. June 19, 2019.
[10] We do not speak to ACE plans in the other Upper Midwest states served by Xcel Energy, since the Company has no coal units in North Dakota, South Dakota, Wisconsin or Michigan.

EPA in October 2015 promulgated, under Section 111(b) of the Clean Air Act, a final rule *Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.*[11] The rule applies to newly constructed, modified, and reconstructed fossil fuel-fired utility boilers and IGCC units, and newly constructed and reconstructed stationary combustion turbines. The trigger for applicability is that construction of the new unit began, or the modification or reconstruction took place, after January 2014. EPA defined the BSER for new fossil fuel-fired utility boilers as highly efficient supercritical pulverized coal with partial post-combustion carbon capture and storage (CCS), with an equivalent performance standard of 1,400 lbs CO_2/MWh gross. The BSER for natural gas-fired stationary combustion turbines operated in a "baseload" configuration is defined as use of efficient natural gas combined cycle technology, with a corresponding performance standard of 1,000 lbs CO_2/MWh gross, while natural gas-fired units (generally simple cycles) operated in a "non-baseload" configuration are given a performance standard of 120 lbs CO_2/MMBtu. Modified and reconstructed units in each category are given their own BSER definitions and corresponding performance standards.[12]

Numerous parties challenged the 2015 rule in the U.S. Court of Appeals for the D.C. Circuit, with the cases consolidated under *North Dakota v. EPA*. At EPA's request, the D.C. Circuit has held the consolidated cases in abeyance since April 2017, pending the Agency's review of the 2015 rule and any resulting rulemaking.

2. Proposed 2018 Replacement Rule

EPA in December 2018 released a proposed rule revising the 2015 section 111(b) rule discussed above. This rule, titled *Review of Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units*,[13] revises the emissions standards for new, modified, and reconstructed fossil fuel-fired electric utility steam generating units. EPA proposes that BSER would not be partial CCS, based on EPA's updated assessment of capital costs of CCS, falling electricity demand, water availability, and limited geographic availability of sites suitable for sequestration. Instead, EPA proposes that BSER is the most efficient demonstrated steam cycle (e.g., supercritical steam conditions for large units, subcritical steam conditions for small units) in combination with best operating

[11] 80 *Fed. Reg.* 64,510, October 23, 2015.
[12] M.J. Bradley & Associates, August 14, 2015, *Summary of EPA's Final Standards of Performance for Greenhouse Gas Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.* Available at https://www.mjbradley.com/sites/default/files/MJB&A%20Summary%20of%20Final%20GHG%20NSPS_Aug14.pdf
[13] 83 *Fed. Reg.* 65,424, December 20, 2018.

practices. EPA proposes a corresponding set of emission standards, ranging from 1,900 lbs CO_2/MWh gross for units with heat input >2,000 MMBtu/hr, to 2,000 lbs CO_2/MWh gross for units with heat input <2,000 MMBtu/hr, to 2,200 lbs CO_2/MWh gross for various other types of units and for modified and reconstructed units.

EPA does not propose revisions to the 2015 rule for stationary combustion turbines. EPA does solicit comment on whether the rule should make allowances for circumstances in which simple-cycle stationary combustion turbines may be called upon to operate in excess of the "non-baseload" threshold in the 2015 rule, e.g. due to high utilization to balance solar and wind generation, and whether such turbines should be given a separate subcategory and standard of performance.

Finally, EPA proposes to retain its original "endangerment" finding as the basis for regulating CO_2 emissions from fossil fuel-fired EGUs, but takes comment on whether it is correct to interpret this finding as a finding made only once for each source category, or whether EPA must make a new endangerment finding each time it regulates an additional pollutant by an already-listed source category. EPA also solicits comment on whether there is a rational basis for declining to regulate CO_2 emissions from new coal-fired units in light of ongoing and projected reductions in power sector CO_2 emissions. The 111(b) revision remains a proposed rule as of this writing.

3. Relevance to Xcel Energy

Xcel Energy commented on the 2015 rule, indicating we did not agree CCS is an appropriate BSER because it was not adequately demonstrated and was not at the time deployed on any commercially operating power plant in the United States. Since that time CCS has been deployed on a small number of commercial units, but remains far from widespread. We believe CCS on *gas* units may become viable in the future, and is one of several potential carbon-free dispatchable technologies that could help achieve our 2050 aspiration of 100% carbon-free electricity. However, Xcel Energy does not have plans to build a new coal-fired power plant, with or without CCS, so the rule's requirements for new coal units have no impact on the Company.

We believe any new natural gas combined cycle unit we may construct would be able to meet the 2015 rule's performance standard of 1,000 lbs CO_2/MWh gross. It is possible that new simple-cycle stationary combustion turbines we build[14] could be called upon to operate in excess of the non-baseload thresholds in the 2015 rule, and

[14] Note that under the Preferred Plan, our modeling calls for no new gas combustion turbines until 2031, and even at that time, gas combustion turbines could be replaced by other resources that meet the same firm peaking need.

could struggle to achieve the 120 lbs CO_2/MMBtu performance standard applicable to such units. Since these units would likely operate this much only because they are supporting integration of higher amounts of renewables, we believe it may be appropriate for EPA to relax the non-baseload threshold or create a separate subcategory and standard of performance for such units. EPA's decision on simple-cycle aeroderivative turbines will become known when EPA finalizes the 111(b) rule.

C. Progress on the State of Minnesota's Greenhouse Gas Goals

The Next Generation Energy Act (NGEA) of 2007 states that:

> It is the goal of the state to reduce statewide greenhouse gas emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, to a level at least 30 percent below 2005 levels by 2025, and to a level at least 80 percent below 2005 levels by 2050.[15]

These goals apply to all economic sectors; the NGEA does not provide goals specific to electricity or other sectors, or to individual companies. The Minnesota Pollution Control Agency (PCA) maintains the state's GHG inventory, publishes data,[16] and provides a biennial report to the Legislature on progress on the NGEA goals.[17]

1. Xcel Energy's CO_2 Inventory and Reporting Methods

Xcel Energy supports timely, transparent public reporting of CO_2 and other greenhouse gas emissions. Our comprehensive GHG reporting is based on The Climate Registry[18] and its *Electric Power Sector Protocol*, which aligns with the World Resources Institute and ISO 14000 series standards. Our company joined The Climate Registry as a founding member in 2007 to help establish a consistent and transparent standard for calculating, verifying and reporting greenhouse gases. Through The Climate Registry, we annually third-party verify, register and publicly disclose our greenhouse gas emissions. We have reported and verified emissions for 2005 through 2017, with verification of 2018 emissions pending. This reporting – which differs in a few respects from PCA's methodology for the state – takes the following approach:

- CO_2 emissions are reported from all owned power plants and purchased power across our Upper Midwest integrated system, serving five states. This is a broader boundary than PCA's method, which considers emissions from power plants within Minnesota and estimates emissions from power imported into

[15] Minn. Stat. §216H.02, subd. 1.
[16] See https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data.
[17] See https://www.pca.state.mn.us/air/state-and-regional-initiatives.
[18] See https://www.theclimateregistry.org.

Minnesota.

- It includes CO_2 from owned fossil fuel-fired power plants, purchased power agreements (PPAs), and power purchased in the wholesale markets. The majority of these emissions (over 80 percent) are directly measured using Continuous Emissions Monitoring Systems (CEMS); a small portion (less than 10 percent) are from PPAs with counterparties whose emission rate is known because they report emissions to EPA, the Energy Information Administration or Federal Energy Regulatory Commission; a still smaller portion (less than 5 percent) are from counterparties who do not have a defined PPA with Xcel Energy and so are assigned a regional grid average emission rate.
- Reported emissions from power generation include CO_2 only, not methane and nitrous oxide. However, methane and nitrous oxide add less than ½ of one percent to our total CO_2-equivalent emissions, even after accounting for the greater global warming potentials of these gases.
- We report CO_2 from electricity provided to our customers. Xcel Energy sells a small portion of the electricity we generate and purchase as short-term sales into the wholesale market. CO_2 from these sales is excluded from our reporting, because the energy does not serve our customers, and it is likely that many companies purchasing the energy account for the emissions in their reporting, so including them in our reporting could result in double counting.

2. State Goal for 2015

PCA's statewide GHG inventory data now covers 2005 through 2016. Statewide GHG emissions declined about 5 percent from 2005 to 2015, missing the statewide goal of 15 percent. Statewide emissions declined more in 2016 – reaching 12 percent below 2005 by the end of that year – however performance varied by sector: electric sector emissions declined 29 percent, transportation emissions 8 percent, agriculture, forestry and land use emissions 12 percent, and waste emissions 6 percent, while emissions in the residential, commercial and industrial sectors all increased.[19]

Thus while the state overall and individual sectors have fallen short of the NGEA goals, the electric sector has approximately doubled the targeted reduction. According to PCA,

> Emissions from electricity used by Minnesotans are down by about 29% since 2005. This means the electricity generation sector has met the Act's 2015 goal, and has nearly

[19] See https://www.pca.state.mn.us/air/greenhouse-gas-emissions-data, as well as PCA's January 2019 report, *Greenhouse gas emissions in Minnesota: 1990-2016: Biennial report to the Legislature tracking the state's contribution to emissions contributing to climate change*, pages 5-6, available at https://www.pca.state.mn.us/sites/default/files/lraq-2sy19.pdf.

> reached the 2025 emissions reduction goal. Moreover, Minnesota's utilities have committed to additional coal plant closures that will further reduce GHG emissions from this sector in the future. Transportation is now the largest source of GHG emissions in Minnesota. This sector will require ongoing, focused effort to reduce emissions to the levels necessary to meet statutory goals.[20]

Xcel Energy's Upper Midwest CO_2 emissions have declined by even more. We provide below our emission reductions to date for three relevant years: 2015, for comparison to the NGEA goal for that year; 2016, for comparison to PCA's statewide data; and 2018, our latest emissions data available. Note that the 2018 data is not yet third-party verified.

Table 1: Xcel Energy Upper Midwest CO_2 Emission Reductions

Year	Total CO_2 from electricity serving customers (million short tons)	Reduction from 2005	Comparison
2015	21.1	25 percent	Exceeding state goal of 15 percent by 2015
2016	19.0	32 percent	More than double state goal for 2015 and exceeding state goal for 2025
2018	18.5	34 percent	More than double state goal for 2015 and exceeding state goal for 2025

3. State Goal for 2025

Under the Preferred Plan, Xcel Energy's Upper Midwest CO_2 emissions are on track for an approximately 60 percent reduction by 2025, doubling the NGEA statewide goal for that year. These reductions reflect our full 1,850 MW wind portfolio being online by that time, significant growth of solar, continued energy efficiency program achievements, continued operation of our carbon-free nuclear units, and retirement of one Sherco unit in 2023 (with the other two units at Sherco and the A.S. King unit retiring by 2030).

4. State goal for 2050

A true transformation has occurred in the electric sector since our last Resource Plan. In that plan, we discussed the state's 80 percent by 2050 goal qualitatively, but identified many technical and economic barriers to creating a Upper Midwest system that serves our customers' electricity needs affordably and reliably with only 20 percent of the CO_2 emissions of 2005. Today, only four years later, Xcel Energy has

[20] *Greenhouse gas emissions in Minnesota: 1990-2016*, page 2.

set a company-wide goal of an 80 percent reduction in CO_2 emissions *by 2030* – i.e. achieving the State's economy-wide goal, twenty years ahead of time. Moreover, we believe we can achieve this reduction cost-effectively, with our expected fleet transition and operational changes and with the renewable, carbon-free generation and energy storage technologies available today. Our 80 percent by 2030 goal is for all eight states Xcel Energy serves; under the Preferred Plan, our Upper Midwest system will achieve about an 84 percent reduction. And our aspiration for 2050 is 100 percent carbon-free electricity for our customers.

In announcing these goals, we stressed that they are not Resource Plans. Our Preferred Plan represents a concrete down payment on those Xcel Energy-wide goals – moving our Upper Midwest system beyond 80 percent reduction by 2030 and putting us on a trajectory to removing carbon from our customers' electricity entirely by 2050. We also made clear that our 2050 aspiration requires technologies not yet commercially available at the scale needed. This cannot be done with only wind, solar, and the short-duration battery storage technologies available today. It will likely require some amount of carbon-free dispatchable generation, longer-duration storage than is available today, more electrification, and more flexible demand. The technologies needed may include gas with carbon capture and storage, power to gas (renewable hydrogen), seasonal energy storage, advanced nuclear or small modular reactors, deep rock geothermal, and other technologies yet to be identified. Each of these options holds promise, but they will require further research, development, demonstration and deployment to become viable solutions at the cost and scale needed. Coupled with supportive federal and state policies, utility Resource Plans can send signals to the market around price, capabilities and timing for when these technologies will be needed.

In sum, we believe the state's goal of 80 percent reduction by 2050 is attainable and affordable within the electric sector, and that even 100 percent carbon-free electricity by 2050 is achievable with sufficient investment in new technology. That said, getting the last 20 percent of carbon out of the electric system is technically challenging and could face steeply increasing costs. This is especially the case if we limit the portfolio to two or three technologies – e.g., wind, solar and short-term storage – rather than creating a balanced portfolio of technologies for an affordable, reliable, and carbon-free system in 2050.

D. Recent Federal and State Legislation

No new state or federal legislation mandating a reduction in GHG emissions from Xcel Energy's system has passed as of filing this plan. However, some legislation has been proposed, which may indicate the potential shape of energy/climate policy in coming years. We summarize here some of those proposals.

1. *Green New Deal*

In February 2019, Rep. Ocasio-Cortez (D-NY) and Sen. Markey (D-MA) introduced H. Res. 109 and S. Res. 59, formalizing one version of the "Green New Deal" (GND) concept of an aggressive mobilization to address climate change combined with nationwide job creation, modeled on the Depression-era programs of the Roosevelt Administration. The resolutions cite recent United Nations and U.S. Government reports on climate risks and propose that, in order to keep global temperature increase below 1.5 degrees Celsius, GHG emissions must be reduced 40-60 percent by 2030 from 2010 levels and reach net-zero global emissions by 2050. The resolutions point to the impacts of climate change in exacerbating systemic injustices and disproportionately impacting certain vulnerable communities, as well as the threat posed to national security, and call for ambitious progressive policies aimed at resolving social injustice as part of the transition.

The resolutions propose it is the duty of the Federal Government to create a GND that would achieve net-zero GHG emissions through a fair and just transition for all communities and workers; create millions of good, high-wage jobs and ensure prosperity and economic security for all; invest in infrastructure and industry to sustainably meet the challenges of the 21st century; secure for future generations clean air and water, climate and community resiliency, healthy food, access to nature, and a sustainable environment; and promote justice and equity by stopping current, preventing future, and repairing historic oppression of indigenous peoples, communities of color, migrant communities, deindustrialized communities, depopulated rural communities, the poor, low-income workers, women, the elderly, the unhoused, people with disabilities, and youth.[21]

To achieve these goals, the resolutions call for a ten-year national mobilization focusing on 1) building resiliency against the impacts of climate change, such as extreme weather; 2) repairing and upgrading infrastructure; 3) meeting 100% of the power demand through clean, renewable, and zero-emission energy sources; 4) building or upgrading energy efficient distributed and "smart" power grids; 5) upgrading all existing buildings for maximum resource efficiency (energy, water) and safety, including through electrification; 6) spurring growth in clean manufacturing; 7) working with farmers and ranchers on sustainable farming and decarbonization of the agricultural sector; 8) development of zero-emission vehicle infrastructure and manufacturing and more public transit/rail; 9) funding for communities with

[21] See https://www.congress.gov/bill/116th-congress/house-resolution/109/text.

pollution related health problems; 10) removing GHG from the atmosphere through proven low-tech solutions such as land preservation and afforestation; 11) restoring threatened and endangered ecosystems; 12) cleaning up hazardous waste sites; 13) eliminating sources of pollution; and 14) promoting international exchange of technologies and expertise on climate.[22]

Notably different from earlier GND proposals, the resolutions do not call for 100 percent renewable energy, but instead a transition to clean, zero-carbon energy, leaving open possibilities non-renewable but zero-carbon sources. They do not call for a carbon price, since at least some of the groups supporting the GND do not favor a carbon tax or cap-and-trade.

Since these GND resolutions are high-level statements of goals and principles for federal programs, rather than specific compliance mandates for electric utilities, we cannot directly evaluate this Resource Plan in relation to them. We note that this Resource Plan appears generally consistent with the resolutions in that it would:

- Reduce Xcel Energy's Upper Midwest emissions 80 percent by 2030, as compared to the GND goal of 50-60 percent;
- Put Xcel Energy on a path to 100 percent carbon-free electricity for our customers by 2050, more ambitious than the GND net-zero goal;
- Prioritize a fair and just transition by working to create new jobs and economic opportunities in the communities hosting retiring power plants, while also creating new employment in building and operating clean energy resources added to our system;
- Focus on reducing conventional pollution and expanding clean energy access for all;
- Improve the resiliency of our electric system and communities;
- Upgrade energy infrastructure and invest in a smarter energy grid, energy efficiency, and electrification of transportation and other end uses.

2. *Clean Energy Standard Act of 2019*

Senators Tina Smith (D-MN) and Ben Ray Luján (D-NM) in May 2019 introduced S. 1359, the *Clean Energy Standard Act of 2019*. This bill, which the authors describe as a path to net-zero emissions in the electric sector by midcentury, would establish a federal clean energy standard (CES) requiring retail electric suppliers to provide an

[22] https://www.congress.gov/bill/116th-congress/house-resolution/109/text.

increasing share each year of the electricity serving their customers from "clean energy" resources, defined to include renewables, qualified renewable biomass, hydroelectricity, nuclear, qualified waste-to-energy, qualified low carbon fuels, qualified combined heat and power, qualified energy storage, dispatchable low- and zero-emission technologies, and carbon capture, storage and utilization. The approach is modeled on state renewable energy standards, but broader since in addition to renewables it allows low- and zero-carbon resources to qualify.

The bill requires retail electricity suppliers with more than 60 percent clean energy today to increase their clean energy percentage (as a share of retail sales plus behind the meter generation) at 1.75 percent per year, while retail electricity suppliers with less than 60 percent today must increase at 2.75 percent per year. Retail electricity suppliers comply with the CES by adding clean energy resources to their fleet, purchasing federal clean energy credits from other retail electricity suppliers, or paying an alternate compliance payment initially set at 3 cents per kWh. Recognizing the need for 24/7 low- and zero-carbon technologies in addition to variable renewables, the bill provides innovation multipliers for dispatchable low-emission and dispatchable zero-emission technologies. It also establishes a new clean energy research, development, demonstration and deployment program within the US Department of Energy.

We believe the Company is well positioned to comply with the CES as introduced. Under our Preferred Plan, the Company would have greater than 60 percent qualifying clean energy from 2019 on, so be required to increase at the slower 1.75 percent per year rate; by 2023, the Company's clean energy percentage would exceed the 90 percent ceiling at which retail electricity suppliers are no longer required to increase until 2040. Due to planned renewable additions, maintenance of our nuclear units, and the proposed relicensing of Monticello, our modeling shows the Company in excess of its compliance obligation throughout the planning period of 2020 to 2034.

3. *Walz/Flanagan Clean Energy Plan*

In March 2019 Minnesota Gov. Walz and Lt. Gov. Flanagan proposed a "One Minnesota Path to Clean Energy," a set of three policy proposals designed to achieve 100 percent clean energy in the state's electricity sector by 2050. The three components are:

- *100 Percent Clean Energy by 2050.* This standard would require all electric utilities in Minnesota to use only carbon-free energy resources by 2050, while allowing each utility the flexibility to choose how and at what pace they meet the standard. The proposal includes provisions to assist workers and communities affected by the transition, while prioritizing local jobs and prevailing wages for large new clean energy projects.

- *Clean Energy First*. This regulatory policy would require that, whenever a utility proposes to replace or add new power generation, it must prioritize energy efficiency and clean energy resources over fossil fuels. This policy would strengthen an existing renewable energy preference in Minnesota law, and it would allow for fossil fuel-based power only if needed to ensure reliable, affordable electricity.
- *Energy Optimization*. This proposal would raise Minnesota's Energy Efficiency Resource Standard for investor-owned electric utilities and expand the Conservation Improvement Program that helps Minnesota households and businesses save on their utility bills by using energy more efficiently. It would also encourage utilities to develop innovative new programs to help consumers and businesses switch to more efficient, cleaner energy. In addition, it would target more energy-saving assistance for low-income households."[23]

To carry out this proposal, the Administration worked with legislators to introduce HF1956, which included all three components above, and SF1456, which included only the Clean Energy First preference. The bills were incorporated into the respective House and Senate omnibus legislation. Ultimately, none of this package of bills passed the Minnesota Legislature in 2019, but they provide an indication of the potential direction of clean energy policy in Minnesota in the coming years. We believe the Preferred Plan positions the Company well to comply with these policies.

II. CONVENTIONAL POLLUTANTS

This section discusses requirements that may apply to emissions of pollutants that are regulated under four primary Clean Air Act (CAA) programs: National Ambient Air Quality Standards (NAAQS), a CAA program that addresses interstate transport of air pollution, CAA programs that address visibility impairment in national parks and wilderness areas, and a CAA program that addresses emissions of hazardous air pollutants. Each program is addressed in turn.

A. National Ambient Air Quality Standards

The CAA requires the EPA to set NAAQS to protect public health and the environment. NAAQS include both (1) primary standards to protect public health, including the health of sensitive populations, such as asthmatics, children and the

[23] See https://mn.gov/governor/news/?id=1055-374280.

elderly and (2) secondary standards to protect public welfare, including protection against damages to animals, crops and buildings. The EPA has established NAAQS for six pollutants: particulate matter (PM), nitrogen oxides (NO_x), sulfur dioxide (SO_2), ozone, carbon monoxide (CO), and lead (Pb). The NAAQS program has been in place since the early 1970s. The EPA is required to review the NAAQS every five years and revise them as appropriate to protect public health and welfare.

Once EPA adopts or revises a NAAQS, states have two years to monitor their air, analyze the data and submit to EPA their recommended classification of the state into Attainment areas (areas having monitored ambient air quality concentrations below the NAAQS), Nonattainment areas (areas having monitored ambient air quality concentrations above the NAAQS), and Unclassifiable areas. The EPA reviews the state's submittal and determines the final area designations a year later. When the EPA designates an area as Nonattainment, the state is given up to three years to develop a new State Implementation Plan (SIP) which identifies actions to be taken to bring the area back into Attainment. A SIP must include emission reduction requirements needed to demonstrate that air quality will attain the NAAQS in the timelines required by the CAA – usually within two to seven years after the SIP is submitted to the EPA for approval.

Recent revisions to all six NAAQS were finalized within the last few years to reflect the latest scientific information about the health effects of these air pollutants. Despite several NAAQS being significantly tightened, there are at present no Nonattainment areas in the state of Minnesota that might result in SIP emission reduction requirements being imposed on Xcel Energy's Upper Midwest power plants. The following table summarizes the current status of the NAAQS Attainment in Minnesota:

Table 2: Xcel Energy Upper Midwest System Status – NAAQS Attainment

Pollutant	Date Reviewed[24]	System Status[25]	Date Designated	Next Review[26]
PM	2012	Attainment	2015[27]	2020
O_3	2015	Attainment	2017[28]	2020
SO_2	2019	Attainment	2018[29]	2024
NO_x	2018	Attainment	2012[30]	2023
CO	2011	Attainment/Maintenance[31]		TBD[32]
Pb	2016	Attainment	2011[33]	2021

Our remaining coal plants are all equipped with scrubbers to control SO_2 emissions as well as air pollution control equipment to control PM emissions. All three Sherco units are equipped with NOx combustion controls that have significantly reduced NO_x emissions from the units. The King plant and our combined cycle gas plants are also equipped with Selective Catalytic Reduction (SCR) technology to control NO_x emissions.

With the planned retirement of Sherco Units 1 and 2, the only additional control equipment that could be required would be SCR technology to further reduce NO_x emissions from Sherco Unit 3. Depending on the date of required compliance, any need to install an SCR to address a NAAQS would either need to be completed by the attainment date or the unit would need to shut down by the attainment date. With the proposed 2030 retirement of Sherco 3, we believe unit retirement may be acceptable in lieu of SCR. Additionally, a full analysis may render the controls not cost-effective

[24] This column reflects the last time each NAAQS was reviewed. Note that in the case of the most recent reviews of the NAAQS for SO_2, NOx, CO and Pb, EPA did not change the level of the NAAQS, so there was no need to initiate a new designation and planning process for those standards.
[25] This column reflects the designation of areas for locations where Xcel Energy's Upper Midwest coal or natural gas plants are located.
[26] This column reflects the date of EPA's announced plans to review a NAAQS, application of the five year CAA deadline for NAAQS reviews, or "TBD" if the five year deadline has passed and there is no announced plan to complete the next NAAQS review.
[27] *See* 80 Fed. Reg. 2206, 2247-48 (Jan. 15, 2015).
[28] *See* 82 Fed. Reg. 54232, 54255-56 (Nov. 16, 2017).
[29] *See* 83 Fed. Reg. 1098, 1134-36 (Jan. 9, 2018).
[30] *See* 77 Fed. Reg. 9532, 9562 (Feb. 17, 2012).
[31] As of 2010, there were no areas of the country in Nonattainment of the CO standard. Areas formerly Nonattainment have all been designated "maintenance" areas, which are subject to certain CAA requirements for two ten-year maintenance periods after achieving compliance with the standards to assure continued attainment. https://www.epa.gov/co-pollution/applying-or-implementing-outdoor-air-carbon-monoxide-co-standards#designations The Minneapolis/St. Paul Metropolitan Area is a maintenance area for CO. https://www3.epa.gov/airquality/greenbook/cbcs.html#MN
[32] Because the last review in 2011 retained the original NAAQS adopted in 1971, we do not expect this standard to change in the future.
[33] *See* 76 Fed. Reg. 72097, 72111 (Nov. 22, 2011), which designated all of Minnesota as attaining the standard, except a portion of Dakota County.

based on the reductions to be achieved.

In addition, if future further emission reductions are needed, it is possible that the state would evaluate whether any upgrades are available to existing controls to further reduce air emissions.[34] Based on the timeline for the next NAAQS reviews shown above, if a standard is made more stringent in the future, and if Minnesota does not meet that standard in areas where our plants operate, further emission reductions might be considered at Xcel Energy's Upper Midwest coal and natural gas plants in the mid to late 2020s.

B. Interstate Transport of Air Pollution

The CAA also requires that NAAQS SIPs include provisions that prevent sources within a state "from emitting any air pollutant in amounts which will … contribute significantly to nonattainment in, or interfere with maintenance by, any other State with respect to any" NAAQS.[35] The EPA has developed programs for the Eastern U.S. that would reduce interstate transport of pollutants emitted by Electric Generating Units (EGUs) that are precursors to ozone and fine particles. NO_x is a precursor to ozone and fine particle formation, while SO_2 is a precursor to fine particle formation.

The Cross-State Air Pollution Rule (CSAPR) was designed as a "cap-and-trade" program that reduces overall emissions from EGUs. This means that total emissions from EGUs in a state or region are limited (the cap), and each ton of emissions allowed is represented by an emission allowance that can be transferred among EGUs (the trade). A cap-and-trade program thus reduces total emissions to the capped amount, but provides flexibility for EGUs to meet their individual emission reduction requirements through installation of control equipment, purchase of emission allowances from other EGUs, or a combination of both.

Depending on EPA's analysis of an upwind state's contribution to Nonattainment in downwind states, CSAPR imposes one or both of the following emission limitations: (1) summer season NO_x emissions (to address ozone), and/or (2) annual NO_x and SO_2 emissions (to address fine particles). In Minnesota's case, the impact of concern has been fine particle Nonattainment areas in downwind states, rather than ozone. The CSAPR has applied since 2015 to Minnesota for fine particle precursors and to Wisconsin for fine particle precursors and ozone. NSP-Minnesota holds sufficient emission allowances to meet CSAPR requirements, while NSP-Wisconsin has

[34] In general, upgrades to existing pollution control technology are far less expensive than installation of an entirely new retrofit control system.
[35] CAA, 42 U.S.C. section 7410(a) (2)(D)(i)(I).

complied through operational changes and some allowance purchases.

EPA has considered further revisions to the CSAPR program as may be needed to address the 2008 ozone NAAQS and the 2012 particle NAAQS. EPA decided that further reductions through CSAPR are not needed to address the 2012 particle NAAQS,[36] and recently decided that further reductions from current emission levels are not needed to address the 2008 ozone NAAQS.[37] It is not known whether or when EPA might consider further emission reductions as part of implementing the 2015 ozone NAAQS.[38]

C. Visibility Impairment in National Parks and Wilderness Areas

Visibility impairment is caused when sunlight encounters pollution particles in the air. Some light is absorbed and other light is scattered before it reaches an observer, reducing the clarity and color of what the observer sees. The CAA established a national goal of remedying existing and preventing future visibility impairment from man-made air pollution in specified "Class I" areas – national parks and wilderness areas throughout the United States, including the Boundary Waters Canoe Area and Voyageurs National Park in Minnesota. The visibility programs focus on reducing emissions of PM, SO_2 and NO_x as pollutants that can result in visibility impairment from EGUs.

The EPA has taken a two-step approach to implement the visibility program. The first step, "reasonably attributable visibility impairment" (RAVI), was implemented in the 1980s to address visibility impairment reasonably attributable to a specific source. The EPA adopted regulations for this program designed to address RAVI, defined as "visibility impairment that is caused by the emission of air pollutants from one, or a small number of sources."[39]

The second step was designed to address widespread, regionally homogeneous haze

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[36] On March 17, 2016, EPA issued guidance for states to analyze interstate pollution impacts and, if needed, to develop plans to address those impacts. EPA stated that few areas would have problems meeting the 2012 particle NAAQS, and plans to address any need for upwind reductions on a case-by-case basis. *Information on the Interstate Transport "Good Neighbor" Provision for the 2012 Fine Particulate Matter National Ambient Air Quality Standards under Clean Air Act Section 110(a)(2)(D)(i)(I),* Office of Air Quality Planning and Standards, at 3.

[37] *See* 83 Fed. Reg. 65878 (Dec. 21, 2018).

[38] On March 27, 2018, EPA issued guidance for states to design their own plans to address interstate air pollution impacts as part of their SIPs under the 2015 ozone NAAQS. https://www.epa.gov/airmarkets/memo-and-supplemental-information-regarding-interstate-transport-sips-2015-ozone-naaqs If in the future states submit plans that EPA does not approve on this issue, EPA could consider developing its own plan at some future date.

[39] 40 C.F.R. section 51.301. Following an allegation that the Sherco plant might have a RAVI-type of impact, NSP-Minnesota entered into a settlement agreement that agreed to tighten SO2 emission limits on all three Sherco units to resolve the allegation. The new limits have been implemented at the Sherco plant. *See* 40 C.F.R. section 52.1236(e), adopted on March 7, 2016 (81 Fed. Reg. 11668).

that results from emissions from a multitude of sources. In 1999, the EPA adopted its Regional Haze Rule (RHR) to address this type of visibility impairment. State environmental agencies are required to submit SIPs that develop and implement their strategy to reduce emissions that may contribute to regional haze. RHR SIPs also must include reasonable progress goals and periodic evaluation/revision cycles designed to make appropriate progress toward the national goal of no human-caused visibility impairment in Class I areas by 2064. These SIPs must be revised approximately every ten years to continue making reasonable progress toward reaching the 2064 national goal.

The Minnesota Pollution Control Agency (PCA) developed, and EPA approved, Minnesota's regional haze plan for EGUs for the first ten-year planning period of the program. The PCA's plan for Sherco Units 1 and 2 required combustion controls to reduce NO_x (Over-Fire Air (OFA), combustion controls and Low- NO_x burners) and scrubber upgrades to reduce SO_2. These controls have been installed and are in operation to reduce emissions from these units.

The PCA will also be required to revise its SIP by 2021 to consider additional emission reductions that may be necessary to continue to make reasonable progress during the next ten year planning period toward achievement of the national visibility goal by 2064.

Our system is equipped with almost all of the pollution control equipment that could be required in future regional haze planning cycles. With the planned retirement of Sherco Units 1 and 2, the only additional control equipment that could be required would be SCR technology to further reduce NOx emissions from Sherco Unit 3. Depending on the date of required compliance, any need to install an SCR to address Regional Haze compliance would depend on unit retirement dates. The Regional Haze program provides some flexibility to agree to a unit retirement some years later than an SCR might otherwise be required, because of the long-term nature of this program. With the proposed 2030 retirement of Sherco 3, we believe unit retirement may be acceptable in lieu of SCR. Additionally, a full analysis may render the controls not cost-effective based on the reductions to be achieved.

In addition, if future further emission reductions are needed, it is possible that the state would evaluate whether any upgrades are available to existing controls to further reduce air emissions. Our remaining coal plants all have scrubbers installed to control SO_2 emissions and have air pollution control equipment to control PM emissions. All three Sherco units are equipped with NO_x combustion controls that have significantly reduced NOx emissions from the units. The King plant and our combined cycle gas plants are also equipped with SCR technology to control NO_x emissions.

D. Regulation of Hazardous Air Pollutant Emissions

Both state and federal regulations require reductions in Hazardous Air Pollutant (HAP) emissions from power plants. In 2006, the Minnesota Legislature passed the Minnesota Mercury Emissions Reduction Act (MMERA). The MMERA provided a process for implementation and cost recovery for utility efforts to reduce mercury emissions at certain power plants, in our case the King and Sherco generating facilities. In 2012, the EPA adopted its final rule establishing National Emission Standards for HAPs from coal- and oil-fired power plants. This rule is often referred to as the Mercury and Air Toxics Standard (MATS), and compliance was required by 2015. Mercury controls have already been installed and are operational on all three Sherco units and at King.[40]

The MATS also set emission limits for acid gases and non-mercury metals. PM is a surrogate for non-mercury metal emissions and SO_2 is a surrogate for acid gas emissions. The Sherco and King plants meet these standards using control technologies and through operational practices.

In 2011, the EPA adopted emission limits for HAPs from industrial boilers to regulate boilers and process heaters fueled with coal, biomass and liquid fuels. These standards apply to biomass combustion at Bay Front Units 1 and 2 as well as to several small heating boilers located at our facilities. Compliance was required by early 2016.

III. WATER

A. Cooling Water Intake Structures

Section 316(b) of the federal Clean Water Act (CWA) requires the EPA to develop regulations governing the design, maintenance and operation of cooling water intake structures to assure that these structures reflect the best technology available for minimizing adverse impacts to aquatic species. The regulations must address both impingement (the trapping of aquatic biota against plant intake screens) and entrainment (the protection of small aquatic organisms that pass through the intake screens into the plant cooling systems).

[40] The CAA requires that EPA review standards such as MATS each eight years to determine if control technology has improved and if the residual emissions left after compliance with the MATS pose additional residual risk to the public. EPA recently proposed to find that, based on its review, no revisions to the MATS are required. 84 Fed. Reg. 2670 (Feb. 7, 2019).

The EPA released a 316(b) rule on May 19, 2014, along with a Biological Opinion issued by the U.S. Fish and Wildlife Service (FWS) and National Marine Fisheries Service (NMFS), and published the final rule in August 2014. The rule requires companies:

- To adopt one of seven options addressing impingement of biota at the entrance to cooling water intake structures, with approval by state or federal National Pollutant Discharge Elimination System (NPDES) permit writers;
- To minimize entrainment of biota into the structures, as directed by the permit writer taking a number of factors into account;
- To implement the impingement, entrainment, and other measures as soon as practicable after the entrainment measures have been identified, with interim milestones the permit writer may set, or for new units upon commencing operations;
- To provide extensive information in permit applications, including source water physical and biological data, intake structure and system data, proposed impingement compliance methods and supporting study plans, previously conducted entrainment studies, and the operational status of the plants; and
- For plants that withdraw more than 125 million gallons per day, to provide two-year comprehensive entrainment characterization studies, technical feasibility and cost evaluation studies, benefit valuation studies, and studies of non-water quality environmental and other impacts, with peer review of the last three.

The rule does not mandate the use of closed-cycle cooling for existing facilities. However qualifying closed-cycle systems will satisfy the final rule's impingement and likely will satisfy its entrainment requirements. The definition of qualified closed-cycle cooling has been broadened to include existing impoundments of waters of the U.S., if sufficiently documented as having been designed to provide a recirculating cooling function or if built in uplands, and to delete references to specific cycles of concentration, percentage flow reduction, and continuous flow constraints.

Regarding Endangered Species Act (ESA) provisions, the final rule requires permit writers to provide copies of applications to the FWS and NMFS, so these agencies can provide input within 60 days on endangered and threatened species and critical habitat potentially affected by intake structures and recommended permit conditions. If permit writers incorporate those conditions and permittees conduct all measures recommended by the Services, the permit will provide "incidental take" authorization. The FWS/NMFS biological opinion provided with the final rule states that the final rule is not likely to jeopardize listed species or destroy or adversely modify designated critical habitat.

The definition of "existing facilities" would include nuclear uprates and other repowered and significantly modified units, even if the turbine, condenser, or fuel are replaced. However, replacement units—essentially newly built, stand-alone units constructed at existing facilities regardless of change in generation capacity, cooling water flow, or use of an existing intake structure—would be considered a "new" unit and subject to closed-cycle cooling equivalent requirements.

The final rule provides a *de minimis* exception for impingement mortality requirements for very low impingement rates, but cautions that ESA-listed species may not be taken. The rule also provides less stringent impingement standards for low-capacity utilization units.

Upper Midwest system power plants that use greater than 2 million gallons per day of surface water are required to comply with the rule. This includes Sherco, Monticello, Riverside, High Bridge, Black Dog, King, Prairie Island, Red Wing, Wilmarth, Bay Front and French Island. Additionally, three plants may be required to reduce entrainment mortality: Monticello, King and Black Dog. The Sherco plant is already a closed-cycle cooling facility and as such, will not likely be required to make significant cooling water intake structure upgrades to comply with the rule.

B. Thermal Discharge

The EPA regulates the impacts of heated cooling water discharge from power plants under CWA Section 316(a). States with authority to implement and enforce CWA programs (e.g. Minnesota, Wisconsin) have state-specific water quality criteria including thermal discharge temperature parameters to protect aquatic biota. Plants must operate in compliance with the thermal discharge temperature parameters. No changes have been made to the thermal discharge temperature parameters in Minnesota. In 2010, Wisconsin implemented new water quality standards regulating the thermal discharge temperature from facilities with state-issued NPDES permits. The new requirements are being incorporated into facility permits as the permits come due for renewal.

Our Bay Front plant in northern Wisconsin was the first Xcel Energy plant to receive new thermal discharge limits, in 2012. Preliminary modeling of the plant discharge indicated that there could challenges to meeting the new requirements. Field monitoring of the discharge showed that the plant was complying with the new thermal discharge limits during normal operations.

French Island does not currently have to comply with the thermal rules. Preliminary evaluation indicates that French Island will have challenges to achieve compliance during the late summer and early fall periods of the year. The existing permit issued in 2018 requires a thermal monitoring plan (due 2020) with monitoring (due 2021). Monitoring data are due with permit application submittal (September 2022). Negotiations with the Wisconsin Department of Natural Resources during permit reissuance will determine what, if any, thermal limits are required.

C. Effluent Limitation Guidelines

As part of the NPDES process, the EPA identifies technology-based contaminant reduction requirements called Effluent Limitation Guidelines (ELGs). The ELGs are used by permit writers as the maximum amount of a pollutant that may be discharged to a water body and apply to power plants that use coal, natural gas, oil or nuclear materials as fuel and discharge treated effluent to surface waters, as well as to utility-owned landfills that receive coal combustion residuals. ELGs are periodically updated to reflect improvements in pollution control and reduction technologies.

The EPA revised the ELG rule on September 30, 2015 with two implementation deadlines. Impacted facilities are required to comply with the new requirements between 2018 and 2023. September 2017, EPA issued a rule postponing certain compliance dates of the 2015 ELG rule while EPA reconsiders portions of the rule. Specifically, EPA delayed the "no earlier than" compliance date so that facilities could not be compelled to comply with rule. EPA plans to issue a revised rule before the 2023 compliance due date and may propose a new compliance timeline.

EPA's 2015 final rule updated the ELGs for flue gas desulfurization systems (FGD), bottom ash transport water (BATW), flue gas mercury control systems (FGMC) and fly ash transport water (FATW) that discharge to surface waters. The final rule addressed discharges directly to surface waters and indirectly to surface waters via municipal wastewater treatment plants. The 2015 rule imposed prohibitions on discharging FATW and BATW either directly or indirectly to surface waters. The rule reduced the levels of contaminants allowed in FGD wastewater discharges. The changes were based on a technology evaluation conducted by EPA. The 2015 final rule had limited impact on our Upper Midwest power plants, with only one unit, the Allen S. King plant, being required to make capital improvements to address the prohibition on discharging BATW. King is studying options for converting the bottom ash system to a dry handled or fully recycled system. The Sherburne County plant is unaffected until the all coal units are retired at which time there may be residual water in the scrubber solids ponds that may need to be managed onsite without directly or indirectly discharging the wastewater.

D. Waters of the United States

In 2015, the EPA and the U.S. Army Corps of Engineers (USACE) issued a rule revising the regulatory definition of "waters of the United States" (WOTUS). The rule significantly expanded the universe of land features and water bodies that are subject to CWA jurisdiction. Under the CWA, federal permitting and oversight are required for any activity having the potential to impact WOTUS. Multiple suits were filed against the rule resulting in the 2015 rule being stayed in 28 states, but not in Minnesota. In February 2019, EPA and USACE issued a proposed rule that would revise the 2015 rule.

Our review of the EPA's 2015 final rule indicates that the new definition would impact the Company in a number of ways by adding complexity, cost and delay to project permitting. Current operations would also be impacted by the imposition of new regulatory requirements to previously exempt on-site or adjacent water bodies or ditches. We expect the rule would:

- Increase the difficulty of siting some projects, since many more areas will need to be avoided or be subjected to extensive and time-consuming CWA permitting;
- Complicate certain distribution line routing/re-routing work by triggering a lengthy permitting process before work can be conducted in or near WOTUS – for example, when the Company is required to reroute our lines due to state and local highway projects;
- Complicate the process to site, permit and construct wind and solar facilities, particularly in areas that have isolated water features. Additional time and cost will be incurred to either obtain the permits or to avoid areas that would trigger the need for federal permitting; and
- Increase cost and potential reliability issues as existing facilities, especially substations, must be retrofitted with additional oil-spill prevention and containment features to prevent an oil release from reaching WOTUS.

We are still evaluating the February 2019 proposed rule, but it appears to improve the clarity of the WOTUS definition, making it easier to define what water features will require federal permitting. Our analysis is not yet complete. EPA expects to finalize the proposed rule in 2020.

IV. COAL COMBUSTION RESIDUALS (ASH)

Coal Combustion Residuals (CCRs), often referred to as coal ash, is residue from the combustion of coal in power plants. Two common types of CCRs are fly ash and bottom ash. Fly Ash is a light material with the consistency of talcum powder that is carried from the boiler with the flue gas. This material is captured by pollution control equipment and may be combined with solids generated from air quality control systems designed to reduce SO_x and NO_x emissions. Bottom ash consists of the heavier materials collected from the bottom of the boiler. CCRs are either recycled for beneficial reuse or disposed of appropriately as non-hazardous industrial waste.

Currently the CCRs resulting from the coal combustion at Sherco Units 1 and 2 are disposed of wet within a permitted, engineered, lined surface impoundment as a non-hazardous industrial waste. The fly ash generated from Sherco Unit 3 is disposed of within a permitted, engineered, lined ash landfill located on plant property. The bottom ash generated from all Sherco units is stored within a lined impoundment as a non-hazardous waste until it can be beneficially used as a construction material or properly disposed on site.

The fly ash from the A. S. King plant is transported for disposal at a permitted, engineered, lined commercial landfill as a non-hazardous industrial waste, while the bottom ash from this facility is beneficially utilized in the manufacture of products. Xcel Energy's operations are subject to federal and state laws that impose requirements for handling, storage, treatment and disposal of wastes. These laws regulate CCRs as a non-hazardous waste under Subtitle D of the RCRA. While Xcel Energy's NSP-Minnesota disposal and storage facilities have been regulated by the Minnesota Pollution Control Agency (PCA) for several decades, they have only recently become subject to regulation under EPA's new CCR Rule.

EPA's CCR Rule became effective on October 19, 2015. This rule was promulgated in response to environmental concerns regarding structural failures and releases of ash directly to the environment from large surface impoundments (e.g. the 2008 Tennessee Valley Authority Kingston ash Impoundment failure and the 2014 release from Duke's Dan River Plant), allegations of inconsistent oversight by the states, and the potential for releases from unlined ash impoundments and landfills to impact drinking water sources.

The CCR rule establishes minimum design and operating requirements for CCR landfills and surface impoundments that are comparable to Minnesota's current requirements under State rules, site-specific permits and operating plans, with specific differences discussed in subsequent paragraphs. Under this rule regulated landfills and surface impoundments are referred to as CCR Units.

The CCR Rule requires ongoing ground water monitoring of each regulated CCR Unit. The rule also defines groundwater protection standards which if exceeded may lead to corrective action. Currently the results from the CCR Rule ground water monitoring program have shown no exceedances of CCR ground water protection standards (GWPS), meaning that no corrective action is required at this time.
The CCR Rule liner performance criteria are different than that established under the PCA's state program. As a consequence the Sherco Bottom Ash clay lined impoundment, is deemed lined under the state rule but is deemed unlined under the CCR Rule. Consequently Xcel Energy is in the process of replacing this impoundment with a new, lined impoundment that meets EPA and PCA requirements. Xcel Energy had previously anticipated the need to replace this impoundment and had plans to replace it by 2023. In order to comply with EPA's CCR Rule requirements Xcel Energy accelerated this project to have the new lined bottom ash impoundment available for use by October 31, 2020. Closure of the existing bottom ash impoundment is scheduled to be completed as originally planned in 2025.

Coal operations ceased at the Black Dog site in April 2015. CCR discharges to the three small impoundments present at the site ceased prior to October 19, 2015. These impoundments were closed by removal on December 12, 2016. The CCR materials removed from the impoundments were disposed of in an off-site, lined landfill. The CCR rule requires the completion of groundwater monitoring at closed CCR sites. Groundwater sampling under the detection monitoring program for this site has commenced and a determination as to whether there is a statistically significant increase (SSI) of groundwater constituents over background concentrations for Black Dog Impoundments 1-3 is due by April 17, 2019.

APPENDIX I – SUPPORTING INFRASTRUCTURE – TRANSMISSION & DISTRIBUTION

The goal of a sustainable, cleaner energy future depends upon sufficient infrastructure to support delivery of renewable and distributed generation resources and customer reliability. In particular, modernized transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, deliver growing levels of choice, increase renewable energy, meet the challenges of emerging technologies, and take a holistic view of resource planning.

As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation, safely and reliably delivering energy to our customers. We also are focused on adopting smarter technologies to further enable distributed energy resources (DER) on our system. We also face new challenges and opportunities for the transmission grid as traditional baseload units retire, large scale renewables significantly increase, and DER are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER on the transmission grid, changes in the market and planning constructs are underway. Other changes are just coming into view and the planning constructs have not yet caught up. We are adapting our planning practices in the interim to ensure reliability and resilience, and we expect substantial new transmission will be needed to support the transformation that is underway.

Overall, we envision building toward an integrated grid that supports the Company's clean energy transition, leveraging the strength of an interconnected system to make the best use of available resources while continuing to serve our customers with resilient and reliable power. We discuss our transmission and distribution systems in greater detail below, including the ways we expect planning to become more integrated over time.

I. TRANSMISSION

The Xcel Energy Operating Companies NSP-Minnesota and NSP-Wisconsin operate an integrated transmission system (the NSP System) comprising more than 8,400 miles of transmission facilities operating at voltages between 23.7 kilovolts (kV) and 500 kV and approximately 550 transmission and distribution substations. The NSP System serves retail customer loads in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan. The NSP System is wholly within the Midcontinent Independent System Operator (MISO) footprint, which is part of the Eastern Interconnection.

The transmission grid in the Upper Midwest has seen significant development over the last 10-15 years. These changes have increased both resilience and capabilities to transport renewable energy from the geographic locations where it is abundant to customer load centers, such as the Twin Cities Metro area. But, as discussed in this Appendix, in Appendix J1: Baseload Study, and in conjunction with the Reliability Requirement we developed for this Resource Plan (Appendix J2), the grid is facing new challenges as traditional baseload units retire, large scale renewables significantly increase, and distributed energy resources (DER) are increasingly adopted.

Below, we provide a brief overview of the NSP System transmission grid and our transmission planning efforts to ensure we maintain customer reliability as the grid transforms and the lines between distribution and transmission blur. We then discuss the challenges in maintaining reliability in *every hour of every day* when the resource adequacy construct relies on an average contribution for a single future planning year. While this is reasonable for firm, dispatchable resources, it does not adequately recognize the intermittent nature of renewable resources – particularly as penetration levels grow – and as we discuss, results in gaps in meeting customers' energy requirements. We then discuss the Reliability Requirement that we developed for this Resource Plan to address this challenge and better ensure grid stability and resilience, and customer reliability. We also discuss the challenges and opportunities associated with interconnecting and efficiently utilizing the substantial new renewable generation we will need to meet our goals, given the current state of the MISO interconnection queue and transmission limitations. Finally, in the balance of this section, we discuss timely issues and summarize our Baseload Study.

A. Transmission System and Planning Overview

The Transmission Business Unit centrally manages Xcel Energy's transmission systems (i.e., NSPM, NSPW, Public Service Company of Colorado, and Southwestern Public Service Company) so that energy is safely and reliably transmitted from generating resources (both Company-owned and third-party owned) to the distribution systems serving our customers. While transmission planning is considered separately from resource planning, these two functions are necessarily interrelated, just as the generating resources and transmission infrastructure on the grid are interrelated. Transmission needs are driven by multiple factors including increased customer electric demand, new or retiring generator interconnections that adjust the flows on the existing transmission system, and generation resource choices and the availability of transmission to meet the demand for these resources. The interconnected nature of the transmission system also means that neighboring utilities' decisions (either transmission or generation) have impacts on the NSP System. Finally, as DER grows, even small retail customer changes at the distribution level may impact the transmission system.

As demonstrated in the Biennial Transmission Plan we submit to the Commission in odd-numbered years, we are constantly reviewing and studying our system to optimize operations and prepare for the future. We independently—and in conjunction with MISO—analyze different futures to assess the system and determine any necessary build-outs, in both short- and long-term planning horizons. Based on these analyses and subsequent implementation, between 2010 and 2018 we invested more than $3 billion in our transmission system. Much of our transmission investment over the recent past has been in implementing the CapX2020 initiative and participating in MISO Multi-Value Projects (MVP), which substantially increased transmission capabilities in the Upper Midwest.

1. *Planning Initiatives*

MISO and the Company perform ongoing and specialized studies to evaluate necessary projects to address issues in the overall MISO system, including the NSP System.

From these studies and our own technical study efforts in support of the Baseload Study we undertook with this Resource Plan, we believe significant additional transmission development will be necessary as we and other utilities retire baseload generating units and add significant renewable resources to the grid toward our commitment to a clean energy future. We also believe changes to the current planning constructs are necessary to properly reflect the trends underway, to ensure system stability and resilience, and customer reliability.

a. Company Biennial Transmission Projects Report

Pursuant to Minn. Stat. § 216B.2425, every other year, the Company – along with the other Minnesota Transmission Owners[1] – submits a Biennial Transmission Projects Report to the Commission reporting on the status of its transmission system. The Biennial Transmission Projects Report lists specific present and foreseeable future transmission inadequacies; identifies alternatives to address system inadequacies;[2]

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[1] American Transmission Company, LLC, Dairyland Power Cooperative, East River Electric Power Cooperative, Great River Energy, Hutchinson Utilities Commission, ITC Midwest LLC, L&O Power Cooperative, Marshall Municipal Utilities, Minnesota Power, Minnkota Power Cooperative, Missouri River Energy Services, Northern States Power Company, Otter Tail Power Company, Rochester Public Utilities, Southern Minnesota Municipal Power Agency, Willmar Municipal Utilities.

[2] Minnesota Transmission Owners define "inadequacy" as essentially a situation where the present transmission infrastructure is unable or likely to be unable in the foreseeable future to perform in a

identifies general economic, environmental, and social issues associated with the alternatives; and summarizes the input that transmission owners and operators gather from the public and local governments to assist in developing and analyzing alternatives.

The 2017 Biennial Transmission Projects Report was filed with the Minnesota Public Utilities Commission in Docket No. E999/M-17-377 on November 1, 2017, and can be found at the Minnesota Department of Commerce's eDockets website at www.edockets.state.mn.us/EFiling or at www.minnelectrans.com. The 2017 report lists more than 90 separate inadequacies throughout the state, including more than 50 newly-identified inadequacies since the filing of the 2015 Biennial Transmission Projects Report. Of the inadequacies identified, 13 involve Xcel Energy.

b. Ongoing MISO Studies

MISO Transmission Expansion Plan (MTEP). MISO has an annual transmission planning process which results in identification of needed transmission facilities.

MISO Generation Interconnection Studies. MISO performs generation interconnection studies to identify facilities necessary to connect new generation resources.

MISO Economic Planning Studies. As part of its planning process, MISO conducts a *Market Congestion Planning Study (MCPS).* The purpose of this study is to determine whether there are transmission projects that could remove transmission constraints and thus more efficiently use available generation resources. The *MCPS* results are reported as part of the annual MTEP report. During the *MCPS* process, projected economic and power flow models are developed which, when analyzed, determine the total production costs that are incurred to provide energy to the MISO load. Transmission constraints – the transmission elements that limit the amount of power that can be transferred between the unused, lower-cost generation and customers – are identified. Through stakeholder discussions, transmission projects are proposed that could mitigate the constraints. The costs for these proposed transmission projects are determined and compared to the amount of production cost savings that could be realized if those projects were in service. The resultant benefit to cost ratio of the projects indicates whether the proposed solutions should be considered for further evaluation for constructability and reliability analysis. Stakeholder review and comments are compiled, and a decision on whether to recommend a *MCPS* project be included in the upcoming MTEP report is made.

consistently reliable fashion and in compliance with regulatory standards.

c. CapX2020 and MVP Regional Development Initiatives

The CapX2020 initiative was a coordinated transmission development effort by a partnership of 11 regional utilities. The results of this coordinated initiative began to be implemented in 2009 and concluded in late 2017. Including the planning, this initiative spanned 13 years, and involved 800 miles of transmission and $2 billion of investment in Minnesota, North Dakota, South Dakota, and Wisconsin.

The approximate lengths, general locations, and in-service dates (ISD) of the CapX2020 projects are as follows:

- *Fargo – St. Cloud – Monticello (ISD mid-2015).* An approximately 240 mile, 345 kilovolt line between Fargo, North Dakota and Alexandria, St. Cloud and Monticello, Minnesota.
- *Brookings County – Hampton (ISD mid-2015).* An approximately 230 mile, 345 kilovolt line between Brookings, South Dakota and the southeast Twin Cities, plus a related 30-mile, 345 kilovolt line between Marshall, Minnesota and Granite Falls, Minnesota. This project is also a MISO multi-value project (MVP).
- *Hampton – Rochester – La Crosse (ISD late 2016).* An approximately 150 mile, 345/161 kilovolt line between Hampton in the southeast Twin Cities, Pine Island near Rochester, Minnesota, and La Crosse, Wisconsin.
- *Bemidji – Grand Rapids (ISD late 2012).* An approximately 70 mile, 230 kilovolt line between Bemidji and Grand Rapids, Minnesota.
- *Big Stone South – Brookings County (ISD late 2017).* An approximately 70 mile, 345 kilovolt line between Brookings, South Dakota and Big Stone City, South Dakota. This project is also a MISO MVP.

MISO MVP is a project type and cost allocation methodology developed through extensive stakeholder discussions in the 2009-2010 timeframe for portfolios of projects that meet one or more of the following three goals:

- Reliably and economically enable regional public policy needs
- Provide multiple types of regional economic value
- Provide a combination of regional reliability and economic value.

The MVP portfolio was intended to enable the delivery of the renewable energy required by public policy mandates, in a manner more reliable and economic than it would be without the associated transmission upgrades. The initial MVP portfolio was approved in December 2011 and combines reliability, economic and public policy drivers and results in a transmission solution that provides benefits in excess of its costs throughout the MISO footprint.

Xcel Energy was a participant in the following MVP projects:

- Big Stone South – Brookings County 345kV (CapX2020)
- Brookings County – Hampton 345kV (CapX2020)
- La Crosse - Madison 345kV (with ATC, also called Badger Coulee)

With the addition of the CapX2020 projects and MISO MVPs, sufficient transmission capacity has existed for the Company to meet its Renewable Energy Standard (RES) requirements to-date. These projects have improved reliability in the region, addressed local reliability issues, and provided a foundation for the interconnection of new generation resources – particularly the renewable resources that have significantly grown over this timeframe. However, many of these lines planned in the early 2000s and completed over the recent past are already fully- or nearly-fully subscribed.

2. *NERC and MISO are Recognizing Potential Resource and Planning Deficiencies*

The North American Reliability Corporation (NERC) conducts a reserve margin analysis across all system operators in North America in a report called the Long Term Reliability Assessment (LTRA). The December 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[3] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation. NERC also recently concluded a special reliability study on the compound effects baseload generating resource retirements on the grid.

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[3] See "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

3. *MISO RIIA Study Initiative*

In preparation for an expected future grid with high levels of non-dispatchable renewable penetration and declining baseload generation, MISO is undertaking additional studies with respect to its system's reliability and resource adequacy of its system. In 2017, MISO initiated a special initiative called the *Renewable Integration Impact Analysis* (RIIA) that is still underway. We incorporated insights from these studies into our Baseload Study that informed our Preferred Plan. RIIA study seeks to inform future long-term planning by understanding what the power system will need to operate reliably with these high levels of variable resources – specifically by examining operational adequacy, transmission adequacy, system stability, and resource adequacy limitations.

a. Renewables Integration Becomes Significantly More Complex Between 30 and 40 Percent Penetration Levels

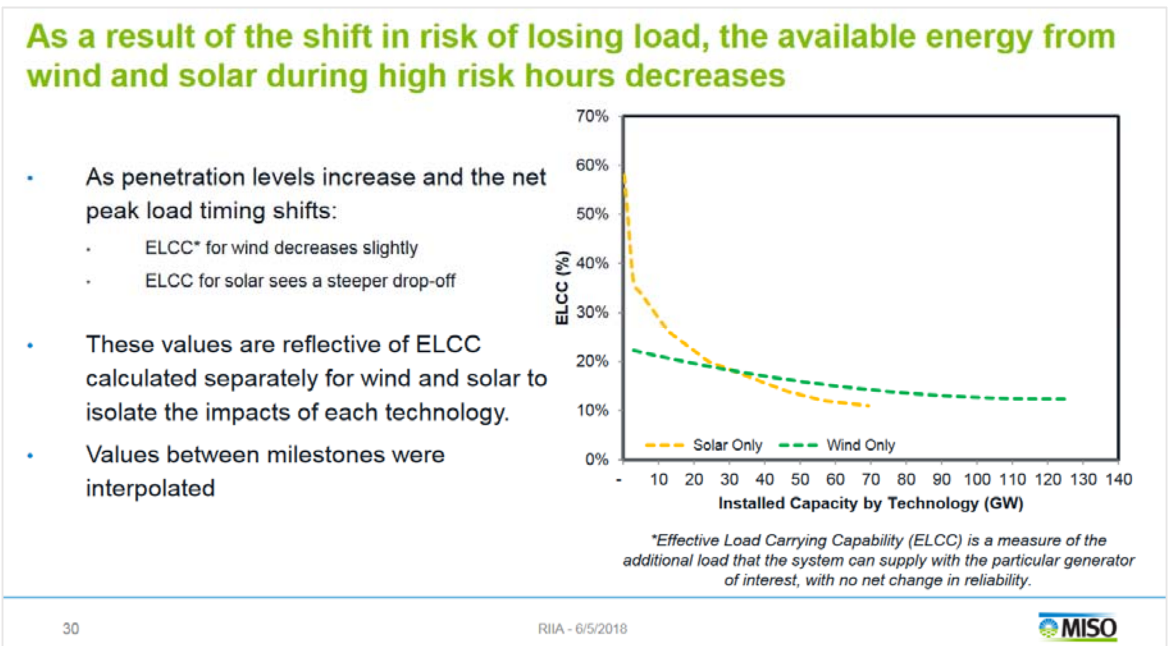
In Phase I, the study examined a scenario in which variable generation achieves a 40 percent share of the total capacity on the MISO system. It found that the complexity of operating such a system reliably is significantly higher than that of even a system with 30 percent variable resources. Under the circumstances studied, the system experienced more dynamic stability issues and other operational stressors, and resource adequacy requirements increased. For example, the modeled system exhibited high levels of energy curtailment and very high ramping rates in the hours when variable resources were not always available to meet demand. In this scenario, loss of load projections were narrowed to fewer likely hours during the year, but the probability of occurrence increased significantly over the current state. This points to the value that flexible, dispatchable resources supporting grid stability continue to provide in these circumstances; while they will run for fewer hours as renewable levels on the grid increase, they are needed – and must be able to respond quickly, moving from minimum generation levels to higher levels of output to meet these fluctuations in net load quickly.

b. Peak Value of Renewables Declines at High Penetration Levels

At high levels of wind and/or solar adoption, the RIIA study found that the accredited capacity values assigned to these resources for resource adequacy purposes degraded – sometimes significantly from current levels. As discussed below, MISO's resource Effective Load Carrying Capability (ELCC) is currently evaluated as an annual average, and forward values are not projected. In reality, however, the capacity value these resources provide to the grid is not consistent – and, as we and other industry members are learning – the capacity values are also subject to diminishing marginal returns. When a single variable resource type increases its penetration level on the grid, each incremental unit of capacity inherently provides a little less capacity benefit to the system than the previous unit.

The appropriateness of these values in reflecting actual grid conditions is therefore dependent on the pace at which wind and solar penetration increases on the grid – and subsequently, how MISO conducts review and adjusts the values. For example, MISO's RIIA study estimates that solar in particular would experience steep ELCC reductions within the first 10 gigawatts installed – and this value continues to drop off at higher levels of adoption.[4] Further, in particular for these variable assets, the realized capacity value may change throughout the year in accordance with seasonally variable environmental conditions.

Figure 1: Modeled wind and solar ELCC as penetration increases[5]



The operational realities surrounding future variable resource additions and their seasonal aspects aside, we continue to use the MISO-determined accredited capacity levels in our planning. As MISO's planning construct is currently limited to one forward-looking value, this presents a risk as we plan our future system. Applying this single value to a 15-year planning period – now knowing that the value of these resources will degrade as we and others add variable renewables to the MISO system

[4] https://cdn.misoenergy.org/20180418%20PAC%20Item%2003d%20174068%20RIIA190532.pdf
[5] MISO. "Renewable Integration Impact Assessment" Workshop presentation June 5, 2018. Available at: https://cdn.misoenergy.org/20180605%20RIIA%20Workshop%20Presentation213125.pdf

– what appears to be a net capacity surplus today, may look quite different in future assessments.

We additionally note that we may encounter other changes to current resource adequacy accreditations for other use-limited resources in the future as well. In general, resources such as demand response (DR) and energy storage would be subject to declining ELCC values as they become more prevalent on the system, in the same way wind or solar ELCCs realistically decline.[6] Notably, MISO is also considering changes to how it accounts for DR capacity accreditation overall, such as enforcing more stringent testing requirements. MISO is also following up on actual performance during DR events, which may result in accredited value reductions going forward. Both these factors mean that the DR we currently register with MISO and depend on as a baseline resource in our portfolio may not yield the same benefits in future years as we have historically expected.

We see emerging challenges and uncertainties in the broader MISO market and industry that indicate that the present planning constructs to ensure reliability are not fully equipped to address. Large numbers of renewable generation projects are in the MISO queue for interconnection study and facing substantial upgrade costs to connect to the grid. We are also facing a transition on the grid, with many of the current abundant baseload/large central generating stations retiring, and high levels of renewable resources coming online and pending in the MISO interconnection queue – and perhaps long-term, DER. This generation transformation changes the flows and impacts the reliability attributes of the grid in ways we and the industry are just beginning to understand. We discuss these issues in greater detail in the following sections.

B. Current Regional Planning Constructs Must Adapt

MISO is charged with several responsibilities, chief of which is overseeing wholesale energy markets in the member region and planning for bulk system reliability (i.e. transmission planning, generator interconnection, and ensuring sufficient reserve margins). Many aspects of MISO's operations affect how we conduct resource planning, but here we focus primarily on system reliability constructs that will be increasingly tested as we and others transition to a fuel mix that relies on high levels of variable renewable resources.

As we have discussed, MISO and its system reliability oversight organization, NERC,

[6] See Appendix P2: RESOLVE and RECAP Low Carbon Scenario Analysis (E3) for further discussion on how marginal ELCC for DR and energy storage resources may decline as adoption increases.

undertake studies to determine the appropriate level of reserve capacity that should be maintained, what effect a resource retirement has on the broader system, and how increasing renewable adoption will change how they analyze and ensure grid reliability. All of these studies point toward an increasingly complex grid that will have to be carefully managed through the transition to a lower-carbon future. Trends are emerging that raise questions regarding whether and how planning constructs may need to adapt to ensure the system remains reliable as baseload generating units continue to retire and be replaced by carbon-free, but variable, renewable energy.

One of MISO's core responsibilities includes administering resource adequacy requirements to enable the Company and other Load Serving Entities (LSEs) across the region to fulfill their obligation to serve customers reliably. MISO's Planning Reserve Margin (PRM) analysis is one important piece of the current reliability planning paradigm. The PRM is an estimation of how much generating capacity, over and above expected customer load, needs to be present on the system to ensure reliability in all but the most extreme circumstances (called a 1-in-10 year Loss of Load Expectation or LOLE). In the 2018 LOLE report, MISO established reference PRM values for both installed capacity (ICAP) and a value that derates the installed capacity value to account for potential outages (UCAP). These UCAP values are also called "accredited capacity." The UCAP PRM for the NSP System for the 2018-2019 planning year was 8.4 percent, which means that the total available capacity on the system needs to be 8.4 percent higher than the expected system peak load to ensure reliability.[7] LSEs, including the Company, apply this PRM to their system planning to determine their capacity obligation to MISO.

MISO bases the accredited capacity values on the expected average contribution each resource will provide to the grid. For firm dispatchable resources, the UCAP values are determined based on historical individual unit operational performance. For intermittent, or variable resources, UCAP values are based on the average performance of each wind or solar resource project/farm. MISO also performs probabilistic analyses of how much capacity from variable resources can be counted on to contribute to peak demand across the year, and captures this in the ELCC. These administratively-set values have a significant impact on how we achieve our carbon reduction goals while maintaining affordable and reliable service. Currently, MISO assigns our wind generation an average ELCC value of 15.7 percent, meaning that for every 100 MW nameplate of installed wind, only 15.7 MW can be counted as capacity toward the PRM. For new solar resources, in the absence of an observed

[7] Note that these are 2018/2019 values. We discuss these two measures of PRM and how we apply them to the NSP System for this Resource Plan in the Minimum System Needs section.

historical value, MISO assigns the current initial year default ELCC of 50 percent.[8]

There are two primary issues with the current resource adequacy construct that we believe have the potential to impact reliability and resilience, and for which we have taken steps in this Resource Plan to mitigate. First, the PRM relies on an average capacity value for each resource. The variable and intermittent nature of renewable resources means that they are not available at all at times. Relying on them to perform 24 hours a day, 7 days a week – particularly as renewable levels rise and current baseload units retire – presents an unacceptable risk to reliability. Second, with significant increases in renewable resources underway, the industry is beginning to recognize that renewable resource contributions to meeting the system peak declines as their levels increase.

MISO's present resource accreditation process only establishes the ELCC for the next planning year. This short-term approach fails to account for the declining value those resources will provide toward meeting customers' needs over the long-term. Average capacity values for variable resources will not ensure sufficient energy for our customers every hour of every day. Instead, maintaining an adequate level of flexible, dispatchable resources is necessary to effectively integrate high levels of renewables is necessary.

We also know that high levels of renewables result in a declining peak contribution and can create system instability. As MISO has studied high levels of renewable penetration on the grid with its RIIA study, it has recognized that its capacity accreditation framework – the manner by which it assesses variable renewables' ability to contribute to peak demand needs – will likely change as these resources become more prevalent on the grid. However, MISO has not yet developed sufficiently robust forward guidance for resource planning processes to account for how those values might change in the future, creating uncertainty in the resource planning process.

C. Reliability Requirement

In response to the planning gaps identified above, we developed a Reliability Requirement, which we discuss in detail in Appendix J2 and summarize below.

As the Company increases the amount of renewable generation in our system, it is

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8 We performed a solar ELCC study, which was designed to determine potential ELCC values for incremental small scale solar generation installations. *See* Xcel Energy Compliance Filing, Docket No. E999/CI-15-115 (August 17, 2018).

important to recognize that these resources cannot alone reliably provide customers the energy they demand every hour of every day, or maintain the stability of the grid. Until such time as new technologies develop to fully transition the grid to carbon-free resources, some level of load-supporting, firm dispatchable resources is necessary for grid resilience and customer reliability.

As noted above, renewable resources like wind and solar are inherently variable and intermittent, and as penetration of these resources increases, their value to meet peak customer needs decreases. These concerns are not limited to the NSP System, but rather run throughout MISO's footprint – and in other regions with increasing levels of renewables. Within MISO and on the NSP System specifically, the gap between renewable resource performance and customer needs has been most pronounced during (but is not limited to) winter months. Although MISO is beginning to recognize these challenges, its current planning constructs do not yet incorporate any measures to address them. We have therefore developed a Reliability Requirement to inform this Resource Plan and mitigate risks to customer reliability and system resilience as MISO determines how to incorporate these issues into its planning process.

The Reliability Requirement we developed for this Resource Plan ensures we have the right mix of resources on our system every hour of every day to meet our customers' needs. We apply the Requirement in our Strategist modeling, and note that while this concept is essential until MISO evolves its capacity construct to provide better direction – the Requirement has little effect in our modeling for this Resource Plan. The model does not select any firm dispatchable additions as a direct result of the Reliability Requirement until 2031. Figure 2 below outlines the general calculation of the Reliability Requirement.

Figure 2: NSP System Reliability Requirement Calculation – 2020 Example

Peak Demand Proxy – 6,400 MW
Minus Firm DR (Winter) Proxy – (200) MW
Minus Firm Market Supply Proxy – (500) MW

Reliability Requirement – 5,700MW
(Firm dispatchable resources)

We discuss the Reliability Requirement in detail in Appendix J2.

D. Regional Transmission Capabilities are Limited

The current state of grid interconnection processes and transmission capabilities in MISO introduces complexity to our planning processes and how we execute on the plan. An overflowing project queue, delayed interconnection studies, and transmission system limitations impose challenges to the economic viability of new renewable generation, and by association – our ability to execute on our clean energy transition plans. MISO is taking action to address a number of these challenges. There are some mitigation measures we expect to utilize in the near-to-medium term, which include carefully managing our interconnection rights at existing sites. In the longer term, however, we see a lack of new transmission development as a barrier to achieving our clean energy goals.

1. Generator Interconnection Queue Delays and Interconnection Costs

The MISO generator interconnection process is designed to allow generators reliable, non-discriminatory access to the electric transmission system, in a timely manner, while maintaining transmission system reliability. Recently, as the number of proposed projects in MISO has expanded significantly, this process has been mired in delays. Delay impacts are particularly evident in the Definitive Planning Process (DPP) phases, where MISO undertakes generation interconnection studies. Current studies are a number of months behind due to the large number of projects in the queue, and a generator interconnection process that allows late withdrawals from the queue.

Despite some recent process reforms, MISO has not been able to keep pace with the expanding queue. And when projects do make it through the DPP, they are sometimes assigned high transmission system upgrade costs that challenge the projects' economic viability. As of early June 2019, there was over 100 GW of new capacity in the active MISO queue, the vast majority of which was of wind and solar projects.[9] Each cycle of the DPP is handling expanding levels of requested capacity. For example, the recently completed cycle for the MISO West region started out with 31 projects totaling 5,700 MW. The April 2019 DPP study cycle, scheduled to begin in March 2020, includes 58 projects totaling 8,800 GW in the same area.[10] While the level of proposed new renewable projects is a positive indication of aspirational renewable development in the region, MISO has also indicated that a substantial amount of this capacity is speculative, in early stages of project development, or

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[9] MISO "Generator Interconnection: Overview." Updated as of June 1, 2019, at: https://cdn.misoenergy.org/GIQ%20Web%20Overview272899.pdf

[10] *See* MISO "Definitive Planning Phase Estimated Schedule." Updated as of June 1 2019. Available at: https://cdn.misoenergy.org/Definitive%20Planning%20Phase%20Estimated%20Schedule106547.pdf

duplicative requests.

Further, the existing transmission system's capability to interconnect new projects without substantial infrastructure upgrades is limited, and thus, the generation interconnection planning studies indicate there will likely be costly upgrades assigned to the prospective generators. In the past, initiatives such as CapX2020 and MISO MVPs socialized a substantial level of transmission infrastructure investment across a large swath of benefitting MISO members, and created the ability to integrate large amounts of new renewable energy. However, renewable resources, and wind power in particular, expanded on the MISO grid faster than expected. As a result, the capacity that CapX2020 and the MVPs created has been largely used. Since these early initiatives, few new transmission lines have been proposed or approved for the purposes of renewable integration.

Generally speaking, this translates to substantial transmission upgrade costs being assigned to the generation projects in the queue. To illustrate, in the recently completed MISO West DPP cycle, the 5,700 MW of studied projects were expected to incur approximately $3.2 *billion* in transmission upgrades if all of them were to interconnect to the system.[11] Such high transmission system upgrade costs can render projects uneconomic, forcing them to withdraw from the queue and requiring additional MISO study on the remaining projects.

2. *Physical and Process Limitations between Regions Further Slows Progress on Clean Energy Development*

Limitations on transmission infrastructure and coordination, both within MISO and between MISO and the Southwest Power Pool (SPP), illustrate further challenges. Within MISO, the transmission system is showing constraints and thus slowing progress toward a cleaner energy future across the Upper Midwest system. Currently, wind generation from the western part of MISO flows toward the load centers in the east, such as the Twin Cities Metro area and load centers beyond the transmission interconnection between Minnesota and Wisconsin. However, existing west-to-east transmission capacity is, at times operating at its limit. The transmission interface across the Minnesota-Wisconsin border in particular is currently stability-limited, and trying to force additional renewable energy through these lines could result in voltage collapses in Northern Wisconsin that would destabilize the grid. Curtailing this energy at its source in the west is operationally and economically inefficient – keeping

[11] *See* "MISO DPP 2016 August West Area Phase 1 Study." Report Number: R008-18. Siemens, September 20, 2018, at xvii.
https://cdn.misoenergy.org/GI_DPP_2016_Aug_West_Phase1_SIS_Report277263.pdf

us from fully utilizing the inexpensive and clean energy to which we have access. However, without additional transmission development, we will more frequently encounter this problem as we add more renewable generation to our system.

Further, coordination (or historical lack thereof) between MISO and SPP introduces challenges to increasing and utilizing more clean energy. First, for projects that can be considered interregional in nature, a project must currently meet economic benefit hurdles in a joint review, as well as separate MISO and SPP regional evaluations. This slows the process significantly, and may overestimate the amount of interconnection upgrades required, adding to project uncertainty and cost. Second, although our load and generation are fully within MISO, the nature of power flows inevitably results in some of our energy entering the SPP system. In turn, both MISO and SPP may charge to transmit that energy from the point of generation to the load, challenging a project's economic viability or raising customer costs for projects already online.

Finally, MISO and SPP disagree on what should happen when one region or the other has to "lean" more on the system than its contracted delivery amounts for a certain time. Where SPP would levy penalties in this scenario, MISO views this situation as a normal and acceptable result of an integrated grid. All of these issues increase transaction costs and uncertainty for a given generation project coming online, and represents a potential barrier to efficiently bringing additional renewable generation to the grid.

3. MISO is Taking Action to Address the Current Process Issues

In response to direction from FERC and a recognition of the challenges described above, MISO is undertaking several actions that could serve to mitigate challenges to bringing new, clean resources online. In essence, these actions allow generation owners to leverage existing interconnection agreements to maximize utilization, and fit renewable additions into the relatively few remaining open spaces on the grid. While we expect these processes to mitigate some of the near-term challenges to additional renewable capacity, they do not address all challenges – in particular, our ability to depend on neighboring regions for renewables and maintaining reliability; we expect that longer term solutions will eventually need to be developed.

a. Generator Replacement Process

Interconnection study delays and speculative queueing are challenges not only to projects that are actually commercially-viable, but also to generation owners who are looking to retire aging assets. Companies that are required to meet a certain level of reserve capacity, like Xcel Energy, face potential compliance and commercial risk if we retire existing assets without the ability to re-utilize that interconnection capacity.

Recognizing these issues, MISO filed, and in May 2019 received approval for, a proposed Replacement Generator Process as part of its Attachment X tariff. This modification intersects with Attachment Y with regard to generation replacement and interconnection rights of current generation owners when a resource retires. The change to Attachment X allows current generation owners to retain and reuse the interconnection rights when a resource retires, within certain technical and timing limitations on the new generator.[12] The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. Per the new tariff language, the replacement generation resource would need to go into service not later than three years after the existing generator retires. Importantly, these replacement projects would be studied outside the traditional DPP timeline, because the transmission infrastructure in the area was built to accommodate the large amount of generation associated with the current generating facility – and customers should be able to continue to take advantage of this infrastructure that they have already paid for rather than fund alternative network upgrade costs. This avoids the significant delays and costs associated with the DPP process.

Maximizing use of existing interconnection rights is essential to timely and cost-effective achievement of the fleet transformation that we set in motion with this Resource Plan. This Tariff change is an important development that will help to facilitate the transformation in a timely and cost-efficient manner for our customers.

b. FERC Order 845 Opens Additional Opportunities for Generation Owners

In 2018, FERC issued Order 845, *Reform of Generator Interconnection Procedures and Agreements*, that also opens additional opportunities for generation owners to add resources to the system outside the normal interconnection queue process.[13] First, the Order directs all transmission providers to develop a procedure to allow interconnection customers to use surplus availability at an existing point of interconnection without that new project entering the full MISO queue and planning process, within certain technical limitations. MISO has referred to surplus interconnection availability as "Net Zero" interconnection because the addition of

[12] In summary, these changes allow for transfer of interconnection rights from a retiring generation resource to a replacement resource that: (1) is located at the same point of interconnection as the retiring resource, (2) is less than or equal to the generating capacity of the retiring resource, and (3) does not result in an adverse impact to the transmission system. *See*: https://www.ferc.gov/CalendarFiles/20190515181059-ER19-1065-000.pdf

[13] *See:* https://www.ferc.gov/whats-new/comm-meet/2018/041918/E-2.pdf

this new project would not result in an overall increase to the interconnection capacity requirements of the site; rather, it would be expected to increase the overall *utilization* of the interconnection site. While MISO allowed Net Zero resources prior to FERC 845, the new Order also allows existing interconnection rights owners the first right to utilize the surplus availability on that interconnection. It also revises the definition of a generating facility to explicitly include energy storage resources. These actions work to support generation owners increasing renewable utilization on existing interconnections, and could support future project hybridization (e.g. solar and storage or wind and storage).

c. Substantial Challenges Remain

We expect that generator replacement, Net Zero, and other FERC Order 845 implementation efforts will alleviate some of the barriers to planning and executing on a future with substantial renewable additions. However, these do not address the underlying challenges around queue length and timeline, intra-MISO and interregional seams congestion challenges, and integrating high levels of renewables reliably and affordably. MISO has recently attempted to mitigate the queue volume challenge by proposing process reforms that increase the stringency of entering this phase of interconnection process; however, while recognizing the challenges MISO faces, FERC recently rejected the proposal.[14] While the Company and others have begun contemplating new MVP-like projects, the lack of alignment across MISO and long lead-times required for such projects mean that these challenges are unlikely to be sufficiently resolved in the near-term.

E. Summary – 2020-2034 Upper Midwest Resource Plan Baseload Study

With this Resource Plan we provide a Baseload Study as Appendix J1. We undertook this study as an outcome from our most recent Resource Plan in which the Commission required the Company to continue its study of potential baseload resource retirements.[15] We started this work as part of our last Resource Plan, as we took action to transition our fleet to achieve dramatic reductions in carbon emissions. Specifically, we studied the technical implications of retiring two of our coal plants – Sherco Units 1 and 2. In conjunction with this Resource Plan, we performed technical analyses to more broadly examine the issue of orderly retirement of our remaining baseload generating units – namely, A.S. King, Sherco Unit 3, Monticello Nuclear, and Prairie Island Units 1 and 2.

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[14] *See* FERC "Order Rejecting Tariff Revisions re: Midcontinent Independent System Operator, Inc. under ER19-637." Available at: https://elibrary.ferc.gov/idmws/file_list.asp?accession_num=20190319-3076
[15] *See* Docket No. E002/RP-15-21, Order Point 14(a) (January 11, 2017).

To understand the technical impacts of retiring one or more baseload generating units, we perform engineering analyses on simulations of the Unit changes that assess the results against established industry reliability and operating criteria. When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently.

The Baseload Study in this Resource Plan is comprised of four primary components:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

The technical studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While these studies are essential and provide important insights, our decades of operating and studying the existing system also provides valuable insights and perspective toward assessing potential impacts from NSP System grid changes. We incorporated this experience into our analysis of impacts. We also supplemented our technical study efforts with relevant industry initiatives that examine the compound impacts of aging baseload retirements and increasing levels of renewable generation – similar to the issues facing the NSP System. The studies use the best available information at the point in time that they were conducted. However, the grid is dynamic, and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured; in addition, reliability measurement criteria may change. The results therefore are a point-in-time representation of the technical issues we expect would occur in a studied scenario.

The MISO Y2 and our Reliability Studies identify grid impacts and potential transmission mitigations necessary to resolve the respective issues the studies identified. MISO performed its Y2 Studies in accordance with their Business Practice Manuals, which generally focus on thermal and voltage issues.[16] We used the MISO planning level estimated mitigation costs from the Y2 studies as an input to our Strategist modeling of the baseload unit retirements. While these may not be the final mitigations, they provide a proxy of potential costs to inform the economic aspect of our Baseload Study. Our technical studies supplemented the MISO analysis to examine traditional NERC reliability measures such as system stability and response. This is an important complement to the MISO Y2 studies to provide a more robust look at potential impacts from baseload changes on the NSP system and regional MISO grid.

The results of our Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Other conclusions and insights from this Study include:

- The retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units.
- We must maintain sufficient firm dispatchable, load supporting resources to ensure customer reliability and to support integration of higher levels of renewable resources.
- Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day.
- Significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.
- From an economic perspective, the scenarios that included early coal retirements and nuclear extensions had the most favorable present value.

Insights gained from this Study also helped to inform our development of a Reliability

[16] *See* MISO Business Practice Manual BPM-020 at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

Requirement (discussed in Appendix J2), which bridges the gap between current regional planning requirements and necessary changes to account for: (1) the variable contribution renewable resources provide to the system, (2) the lack of long-term regional system planning guidance for the expected contribution of renewable resources as penetration levels rise, and (3) the need for sufficient firm dispatchable, load supporting resources to reliably integrate increasing levels of renewable resources.

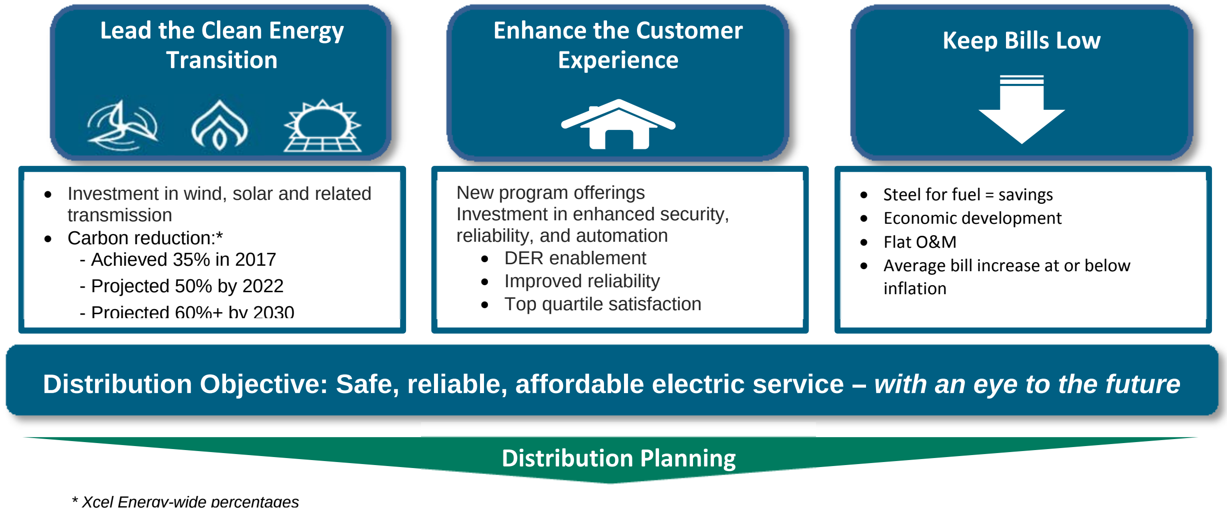
II. DISTRIBUTION

The electric utility industry is in a time of significant change. Increasing customer expectations and technological advances have reshaped what customers expect from their energy service provider, and how those services are delivered. Technologies that customers can use to control their energy usage, such as smart thermostats, electric vehicle (EV) chargers, smart home devices, and even smart phones, are evolving at a fast rate. Influenced by other services, customers have come to expect more now from their energy providers than in the past, including greater choices and levels of service, as well as greater control over their energy sources and their energy use.

At the same time, major industry technological advances provide new capabilities for utility providers to manage the electric distribution grid and service to customers. Electric meters are now equipped to gather more detailed information about customer energy usage, which utilities can leverage to help customers better understand and manage their usage. Other advanced equipment on the grid is able to sense, communicate, and respond in real time to circumstances that would normally result in power outages. Grid operators can also get improved data to better and more proactively plan and operate the grid. These advancements form the foundation for a flexible grid environment that helps support two-way power flows from customer-connected devices or generating resources (such as rooftop solar) and provides utilities with a greater ability to adapt to future developments.

The foundation on which these capabilities rest is safe, reliable energy. Our strategic priorities of enhancing the customer experience, leading the clean energy transition, and keeping customer bills low are embedded in everything that we do – including the way that we plan our distribution system.

Figure 3: Xcel Energy Strategic Priorities – Applied to Distribution



Distribution planning has historically – and still largely today –involved analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels, and utilization rates of major system components such as substations and feeders. Customers traditionally have had limited information about their energy usage and few choices in how they received information, had questions answered, and paid utility bills or conducted other necessary business with their utilities. For the most part, customers were content to receive a monthly paper bill from their utilities and were unaware and unengaged in whether the energy came from renewable or non-renewable sources.

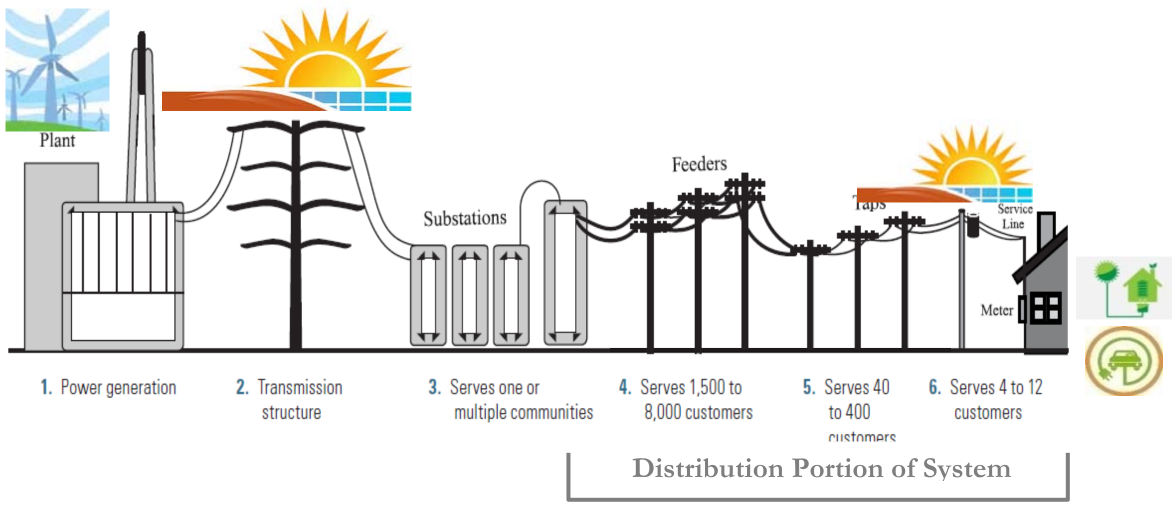
Now, instead of planning just for load, utilities will need to analyze the system for future connections that may be load *or* generation. Also, utilities will increasingly need to view their operations and customer tools from their customers' perspectives. This step change in the distribution utility business will require utilities to plan their systems differently, which will involve not only new processes and methodologies but also new and different tools and capabilities.

Like other aspects of the industry that are transitioning and advancing, we are on the forefront of integrated distribution planning. We submitted the first Integrated Distribution Plan (IDP) in Minnesota November 1, 2018 – which was also among some of the first IDPs nationally. We are taking steps to align and integrate our distribution, transmission, and resource planning processes. We also are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

A. System Overview

The electrical grid is composed of generating resources, high voltage transmission, and the distribution system, which is the vital final link that allows the safe and reliable flow of electricity to serve our customers. We provide an illustration of a modern electrical grid below.

Figure 4: Illustrative Electrical Grid



The poles, lines, and cables that comprise the distribution system connect individual residents and business to the larger electrical grid. The system has been developed for the efficient distribution of power, with lines routed as directly as possible. Geography, however, plays a dominant role in the ultimate design of the system; the location of lakes, road and developments dictate the siting of much of the distribution infrastructure.

Distribution substations are sized for anticipated load at a particular site, and often consist of one to three transformers. Site selection for substations is based on the availability of a transmission source, proximity to the load being served, total ownership costs and reliability considerations. Incremental transformers and feeders may be planned at substation sites to meet future load demand. Where possible, redundancy is built into the system to maintain reliability. Taps are the smaller line segments that leave the mainline and fuses or reclosers are installed at those connection points, which open if a fault develops on the tap. This prevents the remainder of the system on that feeder from having their service interrupted, thus isolating the outage to just the customers beyond that fuse. At the customers' site, service transformers feed lower voltage secondary conductors. These conductors deliver the low voltage power to meters at customers' homes and businesses.

The NSPM electric distribution system serves 1.5 million customers (1.3 million in Minnesota) – and is composed of 1,177 Feeders, approximately 15,000 circuit miles of overhead conductor, and over 11,000 circuit miles of underground cable.[17] The distribution portion of the grid, and the services that the Distribution organization provides, are generally the aspects of our electric service that are most visible to our customers. In terms of reliability, we rank nationally in the 1st quartile.[18]

Key Distribution functions include operating the distribution system, restoring service to customers after outages, performing routine maintenance, constructing new infrastructure to serve new customers, and making upgrades necessary to improve the performance and reliability of the distribution system. We are also out in the community during and after severe weather events as part of our industry-leading storm response efforts to ensure safety, and to promptly restore service to customers.

Key overall Electric Distribution business priorities are:

- *Operational Excellence.* Improve reliability performance level.
- *Grid Modernization.* Install key equipment and systems to operate the new modern grid including monitoring and control, Advanced Distribution Management System, and system efficiency. Targeted renewal of aging, unreliable, or obsolete components and systems (i.e. underground cable, poles, 4kV systems)
- *System Health.* Targeted maintenance of key assets designed to improve reliability and safety – wood poles, substations transformers & breakers, vegetation management.
- *System Capacity Additions.* Installation or reinforcement of key substations and feeders to serve new load and provide backup under emergency conditions (focus on high consequence events).

Distribution priorities and budgets recognize that customers want reliable and uninterrupted power. We therefore must not only proactively maintain our system by making capital improvements when necessary to improve reliability and safety for our customers – we must also manage our budgets to be able to respond to outages

[17] In this context, the number of customers is based on the number of electric meters.
[18] Results for the NSPM operating company, as measured by SAIDI and SAIFI. *See IEEE Benchmark Year 2018, Results for 2017 Data* at:
http://grouper.ieee.org/groups/td/dist/sd/doc/Benchmarking-Results-2017.pdf

caused by severe weather, mandatory work such as relocation of our facilities, and other conditions that cannot be foreseen with a high degree of accuracy. While the immediacy of customer reliability is a reality and a primary focus, in addition to these core activities, our investment plan reflects strategic investments to advance distribution grid capabilities, increase our system visibility and control, and enable expanded customer options and benefits. We are also planning for enhanced distribution planning tools that will equip our system planners with the capabilities to perform DER scenario analysis in our annual planning processes, better facilitate our incorporation of non-wires analysis (NWA) into the analysis we perform to ascertain the best way to meet system capacity needs, and begin in earnest the integration of planning activities at all levels of the grid.

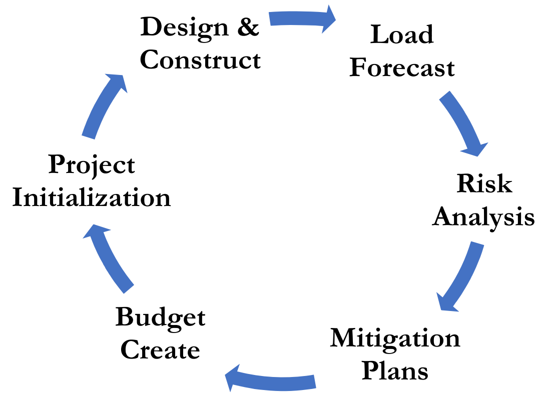
B. System Planning

An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve existing and future electricity loads by evaluating the historical and forecasted load levels and utilization rates of major system components such as substations and feeders. We also consider Hosting Capacity analysis an important aspect of our system planning. We discuss both of these planning activities in this section.

1. Annual System Planning

We do this annually, and additionally conduct analyses during the year in response to new information, such as new customer loads, or changes in system conditions. The process begins with the forecast of peak customer load and concludes with the design and construction of prioritized and funded capacity projects, as illustrated in the below Figure.

Figure 5: Annual Distribution Planning Process



Planning Engineers rely on a set of tools to perform the annual full system snapshot, ongoing distribution system assessments – including assessment of specific DER interconnections – and long-range area assessments. We see our planning practices evolving to analyze future electricity *connections*, rather than just loads. However, we will need to advance our planning tools and capabilities to facilitate greater capabilities to factor-in DER and to more systematically be able to evaluate NWA. Enhanced planning tools have started to emerge in the industry, but will take some time to mature. Toward that end, we have been participating with others in the industry to examine the types of capabilities that may be needed. We also are in the process of evaluating and procuring the next generation of distribution planning tools, which are needed to increase our forecasting and analysis capabilities and impact the integration of planning processes.

2. Non-Wires Alternatives

Non-Wires Alternatives (NWAs) are emerging as another advanced distribution planning application. While a nascent concept only a few years ago, the United States has seen a significant rise in the number of NWA projects proposed and being implemented. States with high DER penetration and/or aggressive regulatory reform, like New York, California, Oregon, and Arizona, are leading the way. Decreasing DER costs in combination with slow or flat load growth may present opportunities for utilities to address pockets of load growth using DER over traditional build out of distribution infrastructure, like reconductoring, transformer replacement, or even new substations. Unlike traditional infrastructure projects, which typically offer fixed capacity increases at known locations, non-traditional solutions often have varying operating characteristics based on their location or the time of day they are used.

More tactically, NWA analysis processes consider several things: a set of criteria for determining which traditional projects are suitable candidates for NWA, processes to develop portfolios of solutions (including both third party resources and non-traditional utility assets), a mechanism to evaluate the costs and benefits of the NWA relative to the traditional solution, procurement processes, and standards to ensure equitable reliability and performance. For implementation and deployment, currently we are seeing NWA solutions which require a disparate set of systems to separately operate the different elements of equipment that would comprise an NWA portfolio solution (e.g. a battery- only platform or demand response- only mode).

Without integration across different systems, this makes the facilitation of NWA a custom, one-off solution that requires extensive oversight and management. To-date, analysis we have performed has determined that the cost of incorporating DER as the primary risk mitigation is at this time still more costly than traditional solutions. However, as technology advances and manufacturing evolves, DERs have the potential to quickly become a cost competitive option. As such, we are working diligently with research groups, internal and external stakeholders, and other utilities that are also incorporating DER planning in order to refine the process of having NWAs solve traditional distribution system deficiencies.

3. Hosting Capacity

We recognize hosting capacity as a key element in the future of distribution system planning. We anticipate it has the potential to further enable DER integration by guiding future installations and identifying areas of constraint. In compliance with Minn. Stat. § 216B.2425 and by order of the Commission, we conducted and submitted annual hosting capacity studies in 2016, 2017, and 2018.[19] We use the EPRI DRIVE tool for our analysis. EPRI defines hosting capacity as the amount of DER that can be accommodated on the existing system without adversely impacting power quality or reliability – and introduced the DRIVE tool as a means to automate and streamline hosting capacity analysis. Our studies have provided hosting capacity results by feeder to serve three purposes: (1) provide an indication of distribution feeder capacity for DER, (2) streamline interconnection studies, and (3) inform annual long-term distribution planning.[20] We expect to continue to evolve our hosting capacity analysis to meet emerging trends and customer needs.

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[19] *See* Distribution System Study, Docket No. E002/M-15-962 (December 1, 2016), Hosting Capacity Report, Docket No. E002/M-17-777 (November 1, 2017), and Hosting Capacity Report, Docket No E002/M-18-684 (November 1, 2018).
[20] See Integrated Distribution Planning Report Prepared for the Minnesota Public Utilities Commission, ICF International (August 2016).

C. Distributed Energy Resources

We continuously evaluate new technologies, new system designs, new equipment, and new operational methods in order to continue to meet the needs of the distribution system in a changing energy environment. These new technologies include emerging advanced grid tools or other advanced field devices with monitoring, controlling, and other capabilities that better enable DER and provide for a more adaptable system.

Some customers are choosing DER, which can reduce customer consumption and even provide energy back to our system from decentralized locations on the grid. Examples of DER include, but are not limited to: rooftop solar panels, energy storage, community solar gardens, or the energy efficiency and demand response enabled by a smart thermostat or time of use electric rate. We are anticipating and preparing for increasing DER penetration levels on our system.

Our customers' adoption of DER and new types of load mean that consumption patterns from our centralized power system are changing. This can represent an opportunity: if we can harness the benefits of these resources to make demand more flexible, we can use this to better match demand to energy production from our large, variable renewable resources. For example, we could utilize managed or "smart" charging of electric vehicles (EVs), to delay charging to off-peak hours or to times when renewable output is the highest. We could also use advanced metering technology alongside customer programs and tariffs to more readily enable load shifting away from peak hours.

DER is also coming onto our system in the form of electric transportation options – enabling not only flexible load opportunities but also broader economy-wide emissions reduction – and we have developed several programs and rate options to encourage that adoption. However, we still often do not have visibility into which technologies, and at what pace, customers will adopt and thus, how we should plan for that changing load to affect our grid needs in the future. While the opportunities are exciting, it is also important to recognize that customer adoption of DER and new types of load behind the meter introduces uncertainties in our planning processes, particularly if we do not have adequate visibility into how and when that new DER or demand is coming onto our system.

The distribution system was initially built to support one-directional flows of energy. Increased DER penetration levels pose new challenges to the distribution system to accommodate two-directional flows. As DER installations increase in an area, feeders or substations may require further analysis to ensure this equipment is adequate to continue providing sufficient power quality and reliable service. Safety is a key concern with higher volumes of distributed energy, as are operational challenges presented by the variability of sources like solar photovoltaic and electric vehicles. DER is also increasingly expected to impact the transmission system, so distribution and transmission planning processes are becoming increasing interrelated.

The Federal Energy Regulatory Commission (FERC) has engaged in the DER trend through its Order No. 841, which addresses participation of storage resources at the transmission and at the distribution level in wholesale markets. We support Order No. 841 as it relates to resources interconnected at transmission level, but have concerns about its implementation as it relates to storage resources interconnected at distribution level.[21] We also have concerns about FERC's proposal in Docket No. RM18-9-000, Participation of Distributed Energy Resource Aggregations in Markets Operated by Regional Transmission Organizations and Independent System Operators, which would expand the requirements of FERC Order No. 841 to all types of DER interconnected at distribution level, not just storage resources.[22]

We addressed what we see as current challenges, which become more significant at higher penetration levels, in comments submitted to FERC. These challenges include:

- *Metering*. Participation of distribution-interconnected storage resources raises the question about how metering will distinguish between charging for wholesale purposes as opposed to charging for retail usage in the case of dual-use facilities. Charging for retail usage should be subject to state-regulated retail rates while charging for wholesale purposes would, under Order 841, be subject to FERC regulated wholesale rates. We are not aware of any metering arrangement that can distinguish between charging for wholesale purposes and charging for retail purposes in the case of a dual-use facility. It should be incumbent upon the resource owner to provide sufficient documentation to ensure that any dual-use resource can be metered in a manner that can distinguish between charging for retail use as opposed to charging for wholesale use. Otherwise, cost shifts to other retail customers will occur as a result of such a resource avoiding payment of full retail rates when it is charging a storage resource for what will ultimately be usage for a retail purpose.

[21] XES filed a request rehearing of various aspects of FERC Order No. 841 as it relates to resources interconnected at distribution level. A copy of XES's request for rehearing is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14651369

[22] A copy of XES's comments in FERC Docket No. RM18-9-000 is available at this link: https://elibrary.ferc.gov/idmws/file_list.asp?document_id=14682284. These comments largely capture input provided in XES's original comments in Docket Nos. RM16-23-000 and AD16-20-000 and XES's request for rehearing in those dockets. FERC declined to accept these comments into the record in Docket No. RM18-9-000 because FERC deemed they were duplicative.

- *Distribution Operations.* Distribution system operators (DSO) need to have the capability to monitor activities of DER in the wholesale market and potentially take action to curtail market sales if such sales will impair reliable distribution system operations. The need for such capabilities will increase as DER penetration increases. The mechanisms to manage these operations will require enhanced communications systems between the DSO, DER, and market operator; software that can monitor distribution system impacts and identify reliability issues and solutions; and additional operations personnel to effectively manage the impacts of DER participation in markets. Cost causation principles dictate that the DER owners and operators should be responsible for the costs associated with these enhancements because such costs would not be incurred "but for" the participation of DERs in wholesale markets. However, absent fairly significant DER penetration levels it is not clear how these costs can be effectively allocated and recovered. At low penetrations there will simply be an insufficient number of customers to bear the costs of these infrastructure upgrades. FERC has not proposed a mechanism to address this issue. In the meantime, DSO will have to find ways to manage DER resource participation reliably, cost-effectively, and in a manner that does not shift costs to other customers.

- *Distribution system upgrades.* Existing distribution systems were not built to manage large outflows of energy that would be associated with market sales. Further, distribution systems are not as flexible as transmission systems and therefore are less able to effectively handle the types of system flows that will occur with DERs participating in markets. Distribution interconnection studies will be more complex and will identify potentially significant feeder and substation upgrades needed to enable market participation by DERs. The costs of such upgrades should be directly assigned to the DER causing such costs to be incurred.

- *Wholesale market issues.* In addition to the direct distribution-level impacts of DERs participating in markets, there are a variety of other issues that must be addressed at the wholesale market level. These issues include the ability to determine where individual DERs involved in an aggregation are located in order to ensure that resources are paid the appropriate nodal price, whether technology exists to effectively manage the state of charge of storage resources, and whether market software can effectively be deployed to manage large numbers of relatively small resources.

MISO was required to make a compliance filing with FERC by December 3, 2018 and has a year thereafter to implement provisions of its compliance filing. One of the key aspects of MISO's compliance filing was relationship between MISO, the DER, and the applicable DSO. FERC is currently evaluating MISO's plans to implement Order 841. Implementation is required by the end of 2019 absent an extension. The Company is also evaluating whether additional steps may be needed to handle the interface between itself, the owners of DER resources, and MISO. Issues that the Company is evaluating include direct assignment of distribution system upgrade costs incurred due to DER participation in wholesale markets, distribution wheeling rates, the need for a DER to establish to the satisfaction of the utility that it has metering capability needed to ensure that it does not charge a storage resource at wholesale rates for retail usage, mechanisms to limit DER output to the extent that reliability of the distribution system is compromised by the DER's activities, and cost recovery for services provided by the distribution system operator to the DER.

We plan to evaluate this issue further and take appropriate steps to move forward to ensure that DER participation in wholesale markets is not subsidized by other retail customers and that such participation is conducted in a manner that does not threaten reliability of the distribution system.

We are taking action to improve our planning tools and modernize our system to more readily integrate increasing levels of DER that we believe are inevitable. We discuss these plans as part of our overall advanced grid initiatives in Part _ below.

D. Advanced Grid Initiative

We are on the forefront of many of the issues and changes underway in the industry and have developed our advanced grid initiative to address them. In addition to the significant steps we have taken to implement and improve our hosting capacity analysis, we are in the process of implementing an Advanced Distribution Management System (ADMS). The ADMS is foundational to advanced grid capabilities that will provide the visibility and control necessary for enhanced planning and significant DER integration. We are also implementing a Time of Use (TOU) pilot, which implements new residential TOU rates, and the installation of Advanced Metering Infrastructure (AMI) meters, in two communities in the Twin Cities metropolitan area, providing select customers with pricing specific to the time of day energy is consumed. This pilot also provides participants with increased energy usage information, education, and support to encourage shifting energy usage to daily periods when the system is experiencing low load conditions.

We also are poised to propose further foundational advanced grid capabilities, including a full AMI implementation, a secure and robust Field Area Network (FAN), and significant reliability improvements for customers through Fault Location, Isolation, and Service Restoration (FLISR). In addition to transforming the customer experience, these foundational investments will allow us to advance our technical abilities to deliver reliable, safe, and resilient energy that customers value. As an example, FLISR and ADMS will reconfigure the grid to reduce the numbers of customers affected by an outage and provide better information to outage restoration crews to speed up their response or avoid those outages in the first place. These foundational investments also lay the groundwork for later years. The secure, resilient communication networks and controllable field devices deployed today through these investments will become more valuable in the future as additional sensors and customer technologies are integrated and coordinated.

We envision that our customer strategy will leverage the more refined customer usage data captured by AMI meters and communicated to utility systems through the FAN to enable new rate, billing, and program options that allow customers to adjust their usage to save money or participate in cost saving programs, using their devices. AMI and FAN also will improve our existing customer portal (MyAccount) information to provide more personalized insights to help customers understand how and where energy is being used and provide ways to help them save money.

However, fundamentally we must replace our present Automated Meter Reading (AMR) system. While it has delivered substantial value for customers since it was implemented in the mid-1990s, our vendor has announced that the technology will no longer be supported after the early-2020s – and they plan to discontinue support for AMR technology entirely in the mid-2020s. At the same time, the AMI technology and market have matured, which has driven many other vendors to also discontinue support of AMR. According to the U.S. Energy Information Administration, AMI adoption surpassed AMR in 2012, and the gap has widened as AMR rollouts have flattened.

We expect three primary outcomes from our deployment of advanced grid infrastructure and advanced technologies: (1) a transformed customer experience, (2) improved core operations, and (3) facilitation of future capabilities.

Transformed customer experience. Advanced grid investments combine to provide greater visibility and insight into customer consumption and behavior. We will utilize this information to transform the customer experience through new programs and service offerings, engaging digital experiences, enhanced billing and rate options, and timely outage communications. These options will provide customers greater convenience and control to save money, access to rates and billing options that suit their budgets and lifestyles, and more personalized and actionable communications. We expect our early initiatives will focus on the execution of services that benefit all customers. Other customer choice programs enabled or enhanced by advanced grid initiatives may include smart thermostats, home area networks, rooftop solar, community solar gardens, optimized EV charging, and other DER offerings.

Improved core operations and capabilities. We also will improve our core operations, making investments to more efficiently and effectively deliver the safe and reliable electricity that our customers expect. While we have historically provided reliable service, we need to continue to invest in new technologies to maintain our performance in the top third of U.S. utilities, particularly as we deliver power from more diverse and distributed resources, and as industry standards continue to improve.[23] Our advanced grid investments provide technologies to manage the complexities of a more dynamic electric grid through additional monitoring, control, analytics, and automation. This will benefit customers through less frequent, shorter, and less impactful outages; more effective communication from the Company when they are impacted by an outage; and reduced costs from our more efficient use and management of assets.

Facilitation of future capabilities. Designing for interoperability enables a cost-effective approach to technology investments and means we are able to extend our communications to more grid technologies, customer devices, and third-party systems in a stepwise fashion, which unlocks new offerings and benefits that build on one another. This building-block approach, starting with the foundational systems, is in alignment with industry standards and frameworks (such as the Department of Energy's Next Generation Distribution Platform (DSPx) framework).[24] It also allows us to sequence the investments to yield the greatest near- and long-term customer value while preserving the flexibility to adapt to the evolving customer and technology landscape. By adhering to industry standards and designing for interoperability, we are well positioned to adapt to these changes as the needs of our customers and grid evolve.

Adherence to industry standards also allows us to better secure the grid and the devices we have connected to it. The increasing number of interfaces associated with grid modernization increases our cybersecurity exposure. As we move forward into the next generation of intelligent, interactive electric distribution, every facet of the electric network must be evaluated for cybersecurity risk. All aspects of the advanced grid must be inventoried, securely configured, and monitored regularly and

[23] See Leading the Energy Future 2017 Corporate Responsibility Report, Page 85, Xcel Energy (May 2018).
[24] See Modern Distribution Grid, Volume III: Decision Guide, U.S. Department of Energy Office of Electricity Delivery and Energy Reliability (June 2017).

thoroughly.

These investments also will produce a wealth of customer and grid data, which will, in turn, enable us to provide the new services described here and enhance existing services. These data-related efforts have begun, and next steps will include identifying the analytics capabilities needed to add additional value to customer offerings or improve utility operations. Data analytics in the utility industry continues to mature, so as grid modernization investments are deployed, these capabilities will evolve as well.

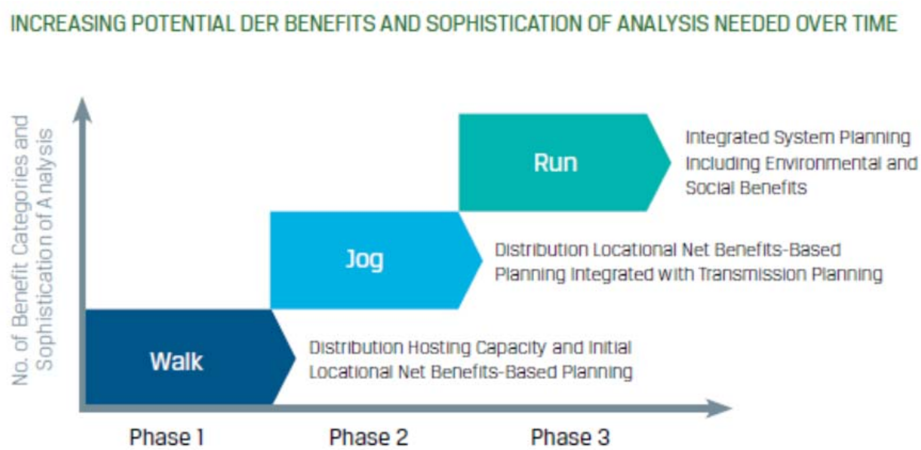
E. Transmission and Distribution Planning are Becoming More Interrelated

Although increasing DER penetration levels will drive integrated resource planning and distribution planning closer together, there are fundamental differences in how these two planning activities assess and develop plans to meet customers' needs. Distribution planning, like Integrated Resource Planning (IRP), charts a path to meet customers' energy and capacity needs, but is more immediate and subject to emergent circumstances because distribution is the connection with customers. Unlike IRPs, five-year plans are considered long-term in a distribution context; and, IRPs are concerned with size, type, and timing, whereas the primary focus of distribution planning is location. Thus distribution loads and resources are evaluated for each major segment of the system – on a feeder and substation-transformer basis – rather than in aggregate, like occurs with an IRP. Before a greater integration of distribution planning, transmission planning, and IRP can occur, distribution planning will need to become even more granular than it is today to address the challenges – and harness the benefits – of DER.

Today, the distribution and transmission planning groups work together as their respective planning processes impact or rely on one another. For example, distribution planning supplies transmission planning with substation load forecasts that are an input into the transmission planning process. These two groups also interact when distribution planning identifies the need for additional electrical supply to the distribution system – and similarly with interconnections, distribution is on point, and involves the appropriate planning resource as needed. The work that we are doing now on customer adoption-based of DER and electrification is helping to bring these planning processes closer together – and we believe will result in better informed sensitivities to ultimately inform both IRP and IDP. However, there are fundamental differences in these planning processes that will continue to challenge integration, at least in the near-term.

Minnesota is among a few states, including California, New York, and Hawaii, on the forefront of advancing its distribution planning as part of its grid modernization efforts. However, each is driven by differing policies and considerations; each is taking a different approach; and, each may result in its own solution that may not fit the circumstances elsewhere. While there are no definitive answers at this point, experts generally agree that a deliberate, staged approach to increased sophistication in planning analyses – commonly referred to as "walk, jog, run" – is important. The below Figure illustrates he stages below.

Figure 6: Staged Approach to Enhanced Planning Analyses



(*Source*: ICF White Paper, *The Value in Distributed Energy: It's all About Location, Location, Location* by Steve Fine, Paul De Martini, Samir Succar, and Matt Robison.

Movement from one stage to another is generally driven by growth in volume and diversity of distribution-connected, DER, the level of evolution of supporting planning practices and tools, and integration with other planning efforts, such as transmission, or resource planning.

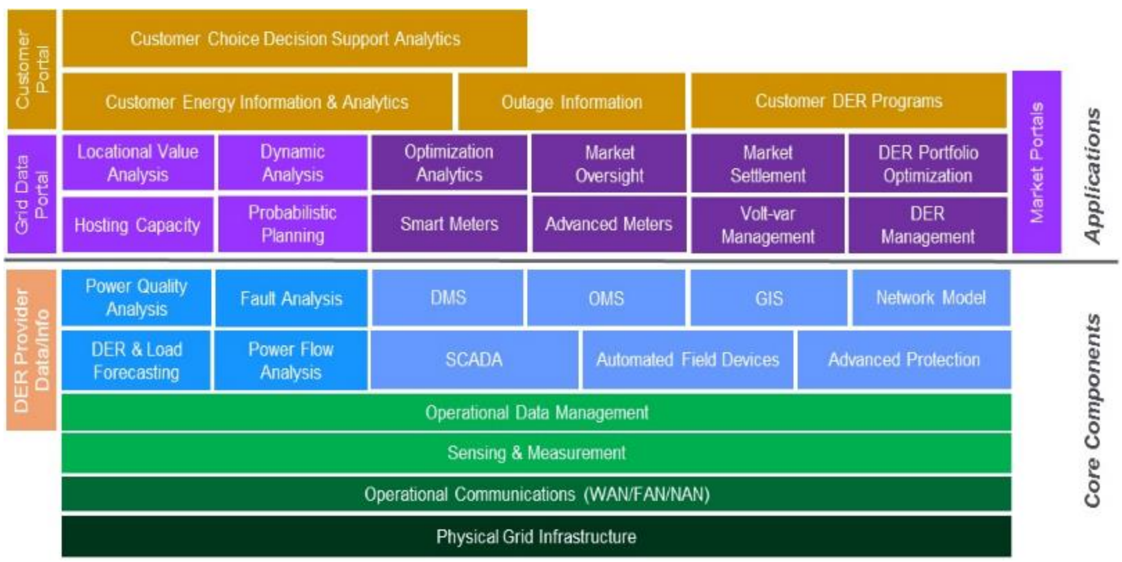
Similarly, the Berkeley Lab report, *Distribution Systems in a High Distributed Energy Resources Future, Planning, Market Design, Operation and Oversight* proposes a three-stage evolutionary structure for characterizing current and future state DER growth, with stages defined by the volume and diversity of DER penetration – plus the regulatory, market and contractual framework in which DERs can provide products and services to the distribution utility, end-use customers and potentially each other.[25] The report emphasizes the need to ensure reliable, safe and efficient operation of the physical electric system, DERs and the bulk electric system, which correlates to Minnesota utility requirements under Minn. Stat. § 216B.04 to furnish safe, adequate, efficient,

[25] Future Electric Utility Regulation series (Report No. 2), by Paul De Martini and Lorenzo Kristov (October 2015). *See* https://emp.lbl.gov/publications/distribution-systems-high-distributed

and reasonable service. The report describes Stage 1 as having low adoption of DERs, where the focus is on new planning studies when DER expansion is anticipated, which also correlates to where we are in Minnesota presently.

The U.S. Department of Energy (DOE), as part of its collaboration with state commissions and industry to define grid modernization in the context of states' policies is developing a guide for modern grid implementation that similarly recognizes foundational elements upon which increased utility tools and information and changes in infrastructure planning, grid operations, energy markets, regulatory frameworks, ratemaking, and utility business models rest, as shown in the below Figure.

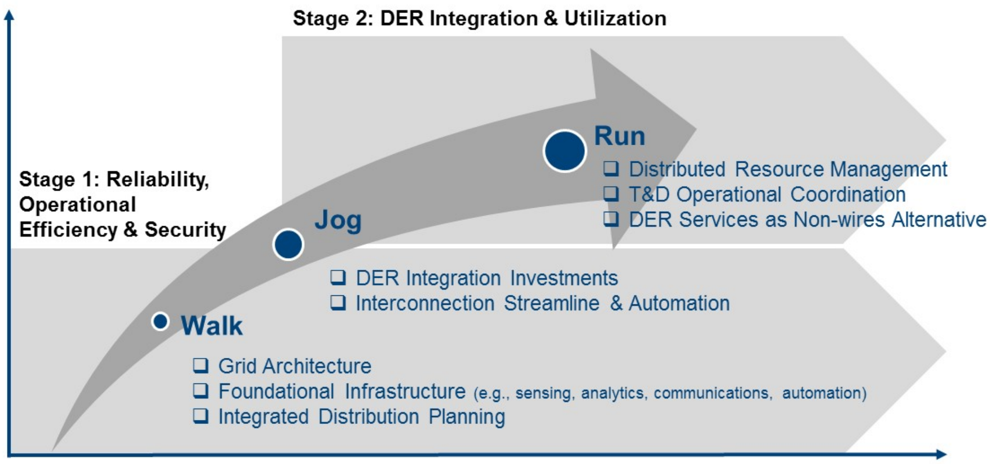
Figure 7: Platform Considerations



Source: *Considerations for a Modern Distribution Grid*, Pacific Coat Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017).

The DOE's efforts also recognize timing and pace considerations, as shown in Figure 8 below.

Figure 8: Timing and Pace Considerations



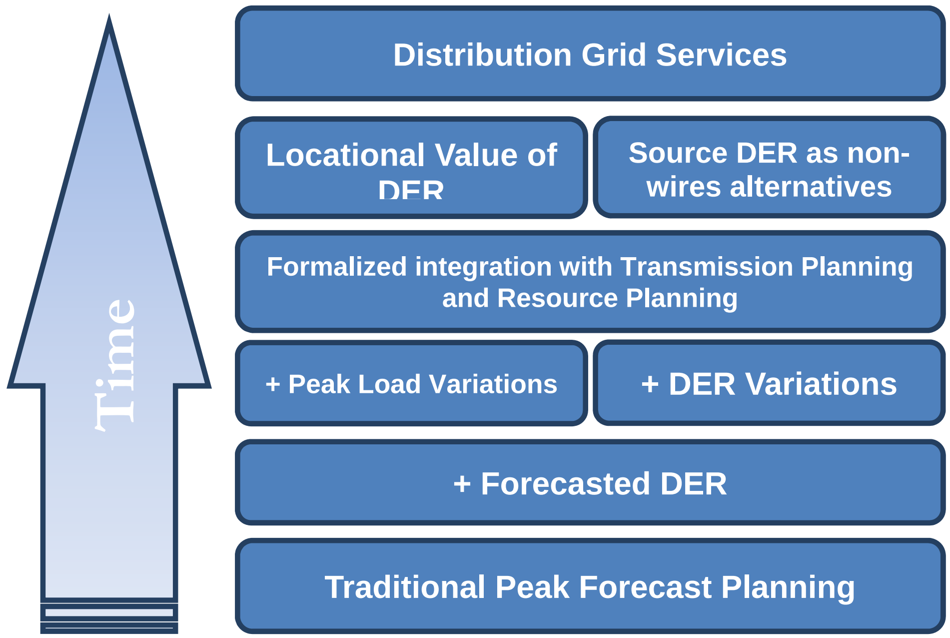
Source: *Considerations for a Modern Distribution Grid*, Pacific Coast Inter-Staff Collaboration Summit by DOE Office of Electricity Delivery & Energy Reliability (May 24, 2017).

As part of the May 24, 2017 Pacific Coast Inter-Staff Collaboration Summit, DOE observed that the U.S. distribution system is currently in Stage 1, with the issue being whether and how fast to transition to Stage 2. Underlying this question however, is the issue of identifying customer needs and state policy objectives – with a goal to implement proportionally to customer value – all of which will differ significantly across states. We agree that Minnesota is in Stage 1. We are focused on foundational infrastructure and starting to evolve our planning tools to enable integrated distribution planning.

A potential progression in planning practices could involve the evolution shown in Figure 9 below, with the drivers of progress being:

- Customer value, such as need, public policy, and cost/benefit,
- Utility readiness, including proper foundational tools and systems, and
- Supporting regulatory frameworks that address cost recovery, and any changes in federal or state market operations, etc.

Figure 9: Potential Evolution in Planning Practices



We expect this progression will need to occur over time as tools improve, policy drivers become clear, and customer value is determined.

Evolving distribution planning to be more like integrated resource planning will need to be thoughtful and planful. Today, IRPs are grounded in Minnesota statutes and rules – and chart a long-term direction of how load can be served in a broad service area. The IRP process is grounded in Minn. R. 7843, which prescribes the purpose and scope, filing requirements and procedures, content, the Commission's review of resource plans, and plans' relationship to other Commission processes, including certificates of need and the potential for contested case proceedings.[26] These processes work for IRPs due to the long-term nature of macro resource additions and changes.

However, distribution planning is more immediate; its full planning horizon correlates to the five-year action plan period of an IRP, which is generally a continuation of past

[26] Minn. R. 7843.0500, subp. 3 prescribes the factors for the Commission to consider in reviewing IRPs. "The Commission shall consider the characteristics of the available resource options and of the proposed plan as a whole. Resource options and resource plans must be evaluated on their ability to: maintain or improve the adequacy and reliability of utility service; keep the customers' bills and the utility's rates as low as practicable, given regulatory and other constraints; minimize adverse socioeconomic effects and adverse effects upon the environment; enhance the utility's ability to respond to changes in the financial, social, and technological factors affecting its operations; and limit the risk of adverse effects on the utility and its customers from financial, social, and technological factors that the utility cannot control."

IRPs. Distribution systems are utilities' point of connection for customers. While an unexpected loss of a macro system component, such as a power plant, can often be covered by the MISO system without interruption of power to customers, loss of a distribution system component often results in a power outage to the customers it was serving. While there is some redundancy in the system to avoid this circumstance, the types of issues addressed by distribution planning are typically much more immediate than IRPs – and do not have a back-up like MISO. Therefore, evolving distribution planning practices will need to be thoughtful – and ensure the focus remains on the immediacy of customer reliability.

While the timeline remains uncertain, it is clear that the distribution grid of the future will look and perform differently than it has over the past 100+ years. Minnesota is in the forefront on the issue of advancing its distribution planning practices with other leaders such as California, New York, and Hawaii. Lessons learned from these states that Paul De Martini, ICF International, shared as part of his presentation at the Commission's October 24, 2016 grid modernization distribution planning workshop included:

- Changes to distribution planning should proactively align with state policy objectives and pace of customer DER adoption.
- Define clear planning objectives, expected outcomes and regulatory oversight – avoid micromanaging the engineering methods.
- Define the level of transparency required for distribution planning process, assumptions and results.
- Engage utilities and stakeholders to redefine planning processes and identify needed enhancements.
- Stage implementation in a walk, jog, run manner to logically increase the complexity, scope, and scale as desired.

No one state has yet figured out the progression of distributing planning enhancements; each is taking a different approach to address the complexities inherent in implementing changes at the right pace and that is proportional to both customer and grid needs – and that realizes net value and benefits for all customers. While the national perspective and other state actions provide helpful points of reference, Minnesota has long been a leader in developing supportive regulatory frameworks to align achievement of policy objectives with business objectives. The increasing complexity of our industry requires a rethinking of the current framework to ensure it is still aligned.

We support the evolution of the grid, and are taking actions to evolve our planning tools and improve our foundational capabilities to support our customers' expanding energy needs and expectations. We support a shift toward more integrated system planning, where utilities assess opportunities to reduce peak demand using DER and to supply customers' energy needs from a mix of centralized and distributed generation resources. However, at a measured pace that correlates to Minnesota policy objectives and customer value.

We are currently evaluating our existing planning processes and tools to determine how to better align and integrate the distribution, transmission, and resource planning processes in the future. Fundamentally, they are rooted in contradictory planning paradigms – with resource planning concerned with size, type, and timing, distribution concerned with location, and transmission somewhere in between. In the near term, we are using the same customer adoption-based DER forecasts and electrification in the IRP and the IDP to the extent practicable – with the IRP having the ability to consider sensitivities. As these planning processes continue to evolve together, it will allow greater ability to consider more potential outcomes – and think about how we can design an optimal portfolio of resources that best meets our overall customer load needs under a range of potential outcomes.

III. CONCLUSION

Our transmission and distribution systems are critical to our ability to serve our customers in a reliable and safe manner, and to deliver growing choice and increasing renewable energy. As we actively prepare our distribution system for the needs of the future, we consider the need for thoughtful investments to meet our core obligation, safely and reliably deliver energy to our customers, and adopt smarter technologies to further enable DER on our system. We recognize and will continue to respond to customer interest in increased DER.

The transmission grid is also facing new challenges and opportunities as traditional baseload units retire, large scale renewables significantly increase, and DER are increasingly adopted. In some cases, such as increasing consideration of distribution-level DER on the transmission grid, changes in the market and planning constructs are underway. Other changes are just coming into view and the planning constructs have not yet caught-up. Overall, we envision building toward an integrated grid in the future that supports the Company's clean energy transition – leveraging the strength of an interconnected system to make the best use of available resources and continue to serve our customers with resilient and reliable power.

APPENDIX J1 – XCEL ENERGY BASELOAD STUDY

I. INTRODUCTION

In our last Resource Plan, we discussed the rapid evolution of our industry due to changing technology, enhanced customer expectations, and the increasing consensus around the importance of carbon reduction. In that plan, we described our vision of an energy future that transitions our generation fleet such that we will achieve a dramatic reduction in carbon. We explained that taking action now to transition our fleet mitigates the costs and risks of retiring a significant proportion of our baseload generation in the same time period. We specifically proposed to accelerate our transition away from coal by ceasing operation of our Sherburne County (Sherco) Units 1 and 2 in 2026 and 2023, respectively.

We provided robust technical analysis supporting our proposed retirement of those coal units, including Midcontinent Independent System Operator (MISO) preliminary retirement studies, a technical analysis that we performed in conjunction with Siemens Power Technologies, and an analysis of our Black Start Plan. We concluded that the most cost-effective way to mitigate technical issues resulting from the unit retirements and continue to meet our customers' load requirements would be to build an intermediate natural gas-fueled plant at the existing Sherco site. The Commission approved our proposed schedule to retire Sherco Units 1 and 2,[1] and found that more likely than not there will be a need for approximately 750 MW of intermediate capacity coinciding with the retirement of Sherco Unit 1 in 2026.[2]

The Commission also required further study of an orderly and cost-effective retirement of our remaining baseload units in our next Resource Plan, as follows:[3]

> In its next resource plan filing, Xcel shall… describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island.

The Baseload Study we performed in support of this Resource Plan builds on the outcomes of our previous plan and includes industry insights, and technical and

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[1] *See* In the Matter of Xcel Energy's 2016-2030 Integrated Resource Plan, ORDER APPROVING PLAN WITH MODIFICATIONS AND ESTABLISHING REQUIREMENTS FOR FUTURE RESOURCE PLAN FILINGS, Ordering Point No. 7, Docket No. E002/RP-15-21 (January 11, 2017).

[2] *Id.* at Ordering Point No. 8. While the Order also addressed next steps for the replacement generation at Sherco, legislation was passed as part of the 2017 Legislative Session that in summary, allows the Company to proceed with the construction of the replacement unit at Sherco in accordance with the parameters specified in the legislation, and without a certificate of need. [Laws of Minnesota 2017, chapter 5—H.F. No. 113, section 1]

[3] *Id.* at Ordering Point No. 14(a).

economic analyses of retirement of our Allen S. King plant, Sherco Unit 3, Monticello Nuclear, and Prairie Island Nuclear Units 1 and 2.

To understand the technical impacts of retiring one or more baseload generating units, we perform engineering analyses on simulations of the Unit changes that assess the results against established industry reliability and operating criteria. The studies use the best available information at the point in time that they were conducted. However, the grid is dynamic, and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured; in addition, reliability measurement criteria may change. The results therefore are a point-in-time representation of the technical issues we expect would occur in a studied scenario.

The Baseload Study we conducted is comprised of four primary components:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

The results of this Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Other conclusions and insights from this Study include:

- The retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units.

- We must maintain sufficient firm dispatchable, load supporting resources to ensure customer reliability and to support integration of higher levels of renewable resources.
- Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day.
- Significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.
- From an economic perspective, the scenarios that included early coal retirements and nuclear extensions had the most favorable present value.

Insights gained from this Study also helped to inform our development of a Reliability Requirement (discussed in Appendix J2), which bridges the gap between current regional planning requirements and necessary changes to account for: (1) the variable contribution renewable resources provide to the system, (2) the lack of long-term regional system planning guidance for the expected contribution of renewable resources as penetration levels rise, and (3) the need for sufficient firm dispatchable, load supporting resources to reliably integrate increasing levels of renewable resources.

We believe the increasing trend toward a clean energy future, along with rapidly advancing technologies and aging generation assets will significantly change the generation mix in Minnesota and across the United States over the next 15-plus years. We have done a comprehensive analysis of the impacts of cost-effective and orderly retirement of our baseload fleet in compliance with the Commission's Order – and in support of our clean energy vision.

The plan we propose in this Resource Plan sets the NSP System on a trajectory to a clean energy future that will continue to power our customer's lives and possibilities with energy they can trust to be safe, reliable, affordable, and progressively clean. It also provides strategic flexibility to adjust as technologies continue to develop; as the industry collectively furthers its understanding of the impacts from the significant changes in the generation mix that are underway; and, while we and others ready the grid with increased transmission capabilities.

This Baseload Study is organized as follows:

I. Introduction
II. Grid Function, Design, and Attributes

III. The Grid is Evolving
IV. Xcel Energy Baseload Retirement Study
V. Summary and Conclusions

II. GRID FUNCTION, DESIGN, AND ATTRIBUTES

The electric "grid" is a large complex machine consisting of generation, transmission and distribution facilities that operate across a very large geographic area. The NSP System is part of MISO, which is part of the Eastern Interconnection that connects the generation and transmission assets of the electrical grids from the Rocky Mountains to the East Coast and from Canada to the Gulf of Mexico. This interconnected network of generating resources and transmission infrastructure works together to seamlessly respond and adjust to dynamic and sometimes adverse circumstances to provide an adequate and reliable supply of electricity to customers. Each resource and system component plays a unique role based on its size, type and location on the system – and because the grid is so integrated, generation changes made to one utility's system impact other portions of the system.

At its core, to preserve system stability and customer reliability, the system must balance generation with changing load conditions and fluctuations caused by other disturbances. Large generating units like our current baseload units afford the capability for the system to "ride through" these disturbances by virtue of their sheer mass. Without the inertia, or resistance to a change in state of motion, afforded by these large units, system stability could be compromised. Similarly, the frequency regulation of the transmission system is governed by the connected generating units. If system frequency deviates beyond allowable levels, protective devices will disconnect generation and/or customer load from the rest of the system. These disconnections can further exacerbate any imbalance between load and generation, which may cause cascading events.

A. Traditional Grid Function

Transmission, in its most basic sense is the connection between generation resources and the customer demand it is intended to serve. Because of that, the transmission system that we have today was traditionally meant to send power from large centralized power stations to the load centers utilizing high voltage transmission lines. These power stations were typically located by the areas of higher customer demand, which would minimize the amount of transmission needed to serve that demand. During the early electrification era, which made modern conveniences like electric lighting commonplace, each utility built, owned and operated their own generation resources and transmission systems meant to serve their customers.

During, and after this initial phase of electrification, growing customer demand for electricity was the primary driver for new, larger and more efficient generation resources and transmission sources meant to deliver that power. Demand growth was overall fairly steady, which allowed for effective long-term planning process to develop. Because of this predictability and the efficiencies found through economies of scale, most generation resources consisted of large coal, nuclear, or hydro facilities. Smaller, more nimble units were also utilized to supplement these large, centralized resources to meet the added stress of summer loads. Regional Coordination, and the "grid" as we know it today, was not a consideration for power companies at this time.

As these individual power companies began to identify efficiencies through coordination with other local power companies that could reduce costs, the full value the centralized power stations provided to the system was also realized. These large scale synchronous generation resources provided the backbone of the stable system we have today. The ability of these generators to provide the primary system support for adverse system conditions such as faults and loss of transmission elements, allowed for increased interconnection between local utilities and greater system reliability.

After the Northeast Blackout in 1965, the benefits of greater coordination, both locally and regionally, were recognized, and Power Pools were formed to share excess resources that each area had. To increase the ability of these resources to be shared amongst the Power Pool members, large bulk transmission facilities were developed to interconnect neighboring utilities and allow for large amounts of power to be transferred in emergencies. As a way to ensure these resources were not stretched too thin, Power Pools also set the amount of generation resources each company was required to keep in order to maintain adequate supply of power.

B. Grid Oversight and Evolution

As the initial phase of electrification was in full swing, the United States Congress established the Federal Power Commission (FPC) to coordinate the hydroelectric project under federal control. The Federal Power Act and Natural Gas Act, passed in 1935 and 1938 respectively, granted the FPC the power to regulate the sale and transportation of electricity and natural gas across state lines. Because of the chronic brownouts of the 1960's and the OPEC embargo in the 1970's, the FPC was reorganized and designated as the Federal Energy Regulatory Commission to oversee federal energy policy and the deregulation of the natural gas industry. The first FERC Order directed specifically at the restructuring of the electric industry was issued in 1996 as Order No. 888. Known as the Open Access Order, the intention of Order

888 was to ensure open and non-discriminatory access to the electric transmission system and encouraged the development of Price Exchanges to increase transparency in energy clearing prices.

Order 888 was followed shortly after by Order 889 to require the posting of transmission availability on a public bulletin board, referred to as the Open Access Same-Time Information System, or OASIS. The issuance of these Orders led to the development of Independent System Operators (ISOs) to facilitate the new requirements, in large part for existing Power Pools, set in place by Orders 888 and 889. In 1999, FERC issued Order 2000, which encouraged participation in Regional Transmission Organizations (RTOs) with the expectation that these RTOs would establish whole electricity markets to enable efficient use of the available resources and transmission system.

1. *The Energy Policy Act of 2005 Created the Present FERC*

The last major development, which led to the FERC we know today, was the passing of the Energy Policy Act of 2005, which greatly increased the authority FERC had over the jurisdictional entities across the country. This included the enforcement of transmission system reliability standards, the ability to levy fines for non-compliance, and other increased authorities. Today, FERC regulates interstate transmission of electricity, natural gas, and oil. Since the passing of the Energy Policy Act of 2005, FERC has issued several major orders to ensure the planning of the most efficient and cost effective transmission system possible through long-term planning requirements as well as ensuring the fair and non-discriminatory operation of wholesale electricity markets across the country.

2. *NERC Oversees and Enforces Grid Reliability*

NERC, created through FERC's increased authority under the Energy Policy Act of 2005, is a non-profit entity that oversees the eight regional reliability systems that stretch from Canada to Mexico. NERC is designated by the FERC as the Electric Reliability Organization, which is the independent entity that develops and enforces mandatory standards for the reliable operation and planning of the bulk electric system (BES) throughout North America. NERC's primary responsibility is to develop power system standards, the monitoring and enforcement of those standards, and ensure power system operators are qualified through training.[4] Analysis of BES impacts from new generation and transmission facilities and changes to existing generation or transmission facilities are measured against NERC standards and

[44] NERC is also responsible for investigating power system outages that have a significant impact.

requirements. We provide an abbreviated outline of NERC Event Category definitions below:

Table 1: Abbreviated List of NERC Event Category Definitions[5]

P1	Single Contingency – Loss of one of the following:
	* Generator * Transmission Circuit * Shunt Device * Transformer * Single Pole of a DC line
P2	Single Contingency – * Opening of a line section w/o a fault * Internal Breaker fault (non-Bus-tie-Breaker) * Bus Section fault * Internal Breaker Fault (bus-tie Breaker)
P3	Multiple Contingency – Loss of one of the following: * Generator * Shunt Device * Transmission circuit * Single pole of a DC line * Transformer
P4	Multiple Contingency – (*Fault plus stuck breaker*) Loss of multiple elements caused by a stuck breaker (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: * Generator * Bus Section * Transmission Circuit * Loss of multiple elements caused by a stuck breaker (Bus-tie * Transformer Breaker) attempting to clear a Fault on the associated bus * Shunt Device
P5	Multiple Contingency (*Fault plus relay failure to operate)* – Delayed Fault Clearing due to the failure of a non-redundant relay protecting the Faulted element to operate as designed, for one of the following: * Generator * Shunt Device * Transmission Circuit * Bus Section * Transformer
P6	Multiple Contingency (*two overlapping single contingencies)* – Loss of one of the following: * Transmission Circuit * Shunt Device * Transformer * Single pole of a DC line
P7	Multiple Contingency (*Common Structure)* – The loss of: * Any two adjacent (vertically or horizontally) circuits on common structure * Loss of a bipolar DC line

NERC additionally authorizes regional entities, which in the Upper Midwest is the Midwest Reliability Organization (MRO). The MRO is a regional entity spanning from Manitoba and Saskatchewan Canada through the United States Midwest. The MRO is primarily tasked with ensuring compliance with reliability standards for the BES. The MRO conducts individual company assessments for any possible areas of improvement or violations.

[5] For a full description of NERC's event categories, *please see*: http://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf beginning at page 8.

3. *Midcontinent Independent System Operator*

The first regional transmission organization to obtain approval by FERC was the Midwest (now Midcontinent) Independent System Operator (MISO); MISO is the ISO for the Upper Midwest. MISO is an independent, not-for-profit company authorized by FERC to provide open-access transmission service, operate the transmission grid, administrate a wholesale energy market, and perform regional transmission planning in 15 states throughout the Midwest, southern United States, and Manitoba, Canada.[6] The Xcel Energy operating companies that comprise the NSP System (Northern States Power Company-Minnesota and Northern States Power Company-Wisconsin) are signatories to the MISO Transmission Owners Agreement and are therefore members of MISO and thus subject to MISO Tariffs and requirements.

MISO's primary function is to ensure open and fair access to the transmission system. In addition, MISO administers the wholesale energy market for the same region.

C. Grid Basics

In this section, we provide an overview of the NSP System, factors effecting reliability, and the role played by baseload generating resources on our system.

1. *NSP System Transmission Overview*

The Twin Cities metro area is surrounded by a double circuit 345 kV *bulk* transmission system that extends from Benton County in the north, east to Chisago County, south to Dakota County, west to Scott County, and back north to Becker, Minnesota. This 600 mile ring of 345 kV lines encompassing nearly 1,300 square miles forms the backbone of the bulk transmission system feeding the Twin Cities load center. This 345 kV ring is connected through several bulk 345 kV lines tying to our neighboring utilities, and a 500 kV bulk transmission line to Manitoba Hydro in the north. These tie-lines connect the Twin Cities load center to the MISO generation market and the Eastern Interconnection – providing important "back-up," should there be an unexpected event that requires the Company to rely on the grid to maintain reliability for our customers.

[6] Independent System Operators grew out of FERC Orders Nos. 888/889 where FERC suggested the concept of an Independent System Operator as one way for existing tight power pools to satisfy the requirement of providing non-discriminatory access to transmission. Subsequently, in Order No. 2000, FERC encouraged the voluntary formation of Regional Transmission Organizations to administer the transmission grid on a regional basis throughout North America (including Canada).

The 345 kV ring that surrounds the Twin Cities feeds the underlying Twin Cities 115 kV transmission grid, which connects to our low voltage distribution system that delivers the power directly to businesses, houses and other loads. The transmission system and the lower voltage distribution system in the Twin Cities area has developed over the past 100 years to serve the growing area, and is constantly being analyzed and updated to ensure optimal and reliable power delivery.

Our BES is currently anchored at the corners by several large coal and nuclear generators that act as the baseload generation for the NSP System. They include Sherco and Monticello in the northwest, and King and Prairie Island in the east and southeast. Together these plants provide over 4,350 MW of capacity[7] and over 29,000 GWh of energy to our customers, which represents 47 percent of the NSP System accredited generating capacity and 65 percent of the system energy.[8] This generation is supplemented by several natural gas generating plants located on the 115 kV system in the Twin Cities. These generating units include Riverside, Highbridge, Black Dog, and Blue Lake.

The 500 kV line that ties into Chisago County substation in the northeast connects the hydro power produced by Manitoba Hydro to the Twin Cities load center. A significant proportion of our wind power is located in southwest Minnesota and is tied into the Twin Cities through a number of lines developed over a period of years to connect the wind-rich areas in southwest Minnesota and South Dakota to the Twin Cities load center. A robust transmission system such as this facilitates the provision of reliable, low cost power to our customers from a diverse mix of generation resources, and mitigates risk from catastrophic events.

The existing grid is a valuable asset and an enabler that has and will continue to support the evolution and growth of our system. The grid has facilitated integration of substantial wind generation onto the NSP System by absorbing the inherent fluctuations of this variable generation type over a large area. Transmission enables the transfer of wind and solar and other types of generation from where it is most effectively located to customer load located elsewhere where it can be utilized to the fullest extent.

2. *A Reliable Grid Must Weather Unexpected Failures and Events*

NERC defines a reliable BES as one that is able to meet the electricity needs of end-use customers even when unexpected equipment failures or other factors reduce the

[7] Nameplate capacity ratings.
[8] MISO accredited capacity values.

amount of available electricity, and divides reliability into two categories:[9]

- *Adequacy*. Adequacy means having sufficient resources to provide customers with a continuous supply of electricity at the proper voltage and frequency, virtually all of the time. Maintaining adequacy requires system operators and planners to take into account scheduled and reasonably expected unscheduled outages of equipment, while maintaining a constant balance between supply and demand.
- *Security*. For decades, NERC and the bulk power industry defined system security as the ability of the bulk-power system to withstand sudden, unexpected disturbances, such as short circuits or unanticipated loss of system elements due to natural causes. In today's world, the security focus of NERC and the industry has expanded to include withstanding disturbances caused by manmade physical or cyber-attacks. The BES must be planned, designed, built and operated in a manner that takes into account these modern threats, as well as more traditional risks to security.

Electrical system reliability can be defined as the ability of the electrical grid, which includes transmission, generation, distribution and related components, to serve customer load under any system condition. Maintaining a reliable electricity supply for customers requires that generation, load and electrical losses balance – and maintain a 60 Hz frequency. If the frequency varies only one or two tenths of a hertz from 60 Hz, it can cause damage to equipment, and automated protection schemes will disconnect pieces of the grid to avoid damaging equipment.

A strong transmission system improves the reliability of the electric power system, and facilitates a diverse and low cost resource portfolio for customers – allowing lower cost resources with diverse fuel types, and resource types not available in the immediate area to be efficiently transported to serve their needs. For example, wind resources need to be constructed where the wind is strongest and most consistent; large-scale solar resources where there is sufficient land and the most consistent sunshine – both of which are generally away from large population centers. A robust transmission system brings together varied generating units – some built to run continually, others only to run at peak times when they are most needed, and renewable resources on an intermittent basis – together into an integrated grid.

The system must also be able to facilitate both "active" and "reactive" power, which are typically produced by non-renewable generating unit types. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power,

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[9] http://www.nerc.com/AboutNERC/Documents/NERC%20FAQs%20AUG13.pdf

measured in volt-amperes reactive (VARs), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If reactive power cannot be supplied promptly and in sufficient quantity, voltages deteriorate and, in extreme cases, can result in a voltage collapse.

The grid must also be able to adjust to changing customer loads, the availability of diverse resources, and have sufficient redundancy built-in, making it capable to withstand the failure of its most critical lines, generators, or other components. As customer load changes over the course of a day, generation must change to accommodate the load at any given time. With the high penetration of renewables on the NSP System, we must ensure that we have adequate firm dispatchable, load supporting generation to both accommodate the load and whatever generation mix we have at each point in time. We must also maintain a spinning reserve – generation that is available at a moment's notice – to account for the largest contingency in the area.[10] Having large coal generating units has helped, because they have the ability to be "turned up" and "turned down" based on the level of renewable generation being delivered to the system at any given time. With our proposed plan to retire the remaining coal units on the NSP System, other load supporting generating resources will be needed to perform these important reliability functions.

3. *Role of Baseload Generating Resources*

As we have discussed, the ability to provide reliable electric service depends on a complex and interconnected network of generating resources and transmission infrastructure that provides capacity and delivers energy to customers. Each resource and system component in the network plays a unique role based on its size, type and location on the system. In fact, the Upper Midwest grid and the NSP System has been designed around the current baseload units, and relies on the unique aspects of these units to not only generate capacity and energy for our customers, but also to provide numerous essential system operational services.

When analyzing the impacts of ceasing operations at one of our existing coal or nuclear units, it is important to consider these operating and technical characteristics beyond just the unit's energy output. These include:

[10] Spinning Reserve is unloaded operating capacity available on units connected to and synchronized with the interconnected electric system and ready to take load immediately in response to a frequency deviation.

- *Power Deliverability*. The existing transmission system has been developed to be able to receive the approximately 2,400 MW of power injected from Sherco,[11] 671 MW injected from Monticello, 598 MW injected from King, and 1,150 MW injected from Prairie Island and to deliver it to various area substations to meet the electrical power demands of customers.[12] This power deliverability capability is often referred to as "transfer capability" or "thermal limits" of the system. Transmission systems are made capable of receiving and moving power from specific generators at specific locations; changing generator characteristics or locations requires corresponding changes to grid capabilities.

- *Dynamic Stability*. The transmission grid is a vast interconnected machine with many parts. There are a mix of large and small gears in this machine, all spinning at the same rate (i.e. synchronous), simultaneously producing and delivering electricity to customers. Generating units are the spinning gears in this machine. Large generators like Sherco Unit 3 and King have large spinning shafts that provide a strong backbone for the machine's operation. With enough of these big "gears" spinning, the machine can stay electrically stable and continue operating without interruption when small gears drop in and out of operation (like when the wind stops blowing or sun stops shining), or when another big gear drops out, or a "contingency," happens to some part of the machine. These large gears are also more likely to stay connected to the grid during a contingency than the small gears because large rotating masses have more inertia and are therefore not as easily jarred, or disrupted by a disturbance. Having the large gears in place also enables more small gears to be connected to the machine because they don't have as much impact with the large gears in place. The large generating units thus provide "dynamic stability" to the grid.

- *Fault Current*. Large synchronous generating units provide "fault current," which is necessary for the system protection equipment to function properly. If the system has too little fault current, it is difficult for system protection systems to differentiate customer load from an electric fault, which could cause the protection system to not function properly.[13] The protection system is the overarching electrical monitoring scheme that assesses the real time condition of the transmission grid and acts to prevent damage to system components and prevent cascading failures. The large generating units operating today are important sources of fault current, and the protection

[11] Nameplate capacity ratings of entire site. SMMPA owns 41% of Unit 3 (approximately 380 MW).
[12] Nameplate capacity ratings.
[13] For example, the protective equipment could misinterpret the load as a fault, and de-energize an unfaulted circuit.

system and existing deployed assets rely on sufficient fault current for the protection system and other electrical facilities to work as designed. Many of the electric devices that are deployed on the grid and in service today, such as wind generators and other assets, are engineered and designed to function properly with the amount of fault current that has been historically available on the grid. Therefore, changing the amount of fault current on the grid could not only impact protection systems, but could also impact other electric assets.

- *Black Start Capability.* In the event of a major regional grid outage, firm dispatchable generating units with a secure fuel source are an integral resource to restoring power to the electrical grid, or "restarting the machine." Only firm dispatchable generating units of a certain size that are capable of creating and absorbing reactive power are eligible to perform black start functions. Once Sherco Units 1 and 2 retire, the Sherco Combined Cycle (CC) will be an important part of our black start plan. Renewable generation, such as solar and wind are not currently considered eligible Target Units due to their inherent intermittent nature, and their inability to provide or absorb reactive power. A large battery energy storage system can be configured to be technically capable of providing black start service, likely as part of a relatively small Initial Black Start Unit. However, they may not yet be economically viable for this purpose. There are also technical concerns with regard to how batteries can absorb reactive power, which would be needed if the battery was not paired with another type of generation asset.

- *Voltage Support.* The real time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. Large synchronous power sources like our current baseload units, provide significant system voltage support along with necessary "reactive power." Reactive power is required to start and run motors, like in air conditioners and industrial equipment (called "inductive loads"). Large population centers generally require large generating units located reasonably nearby to support system voltage effectively. As in the dynamic stability discussion, without enough large units in place, the machine isn't as capable and robust when it runs.

- *System Regulation.* System regulation essentially means the ability of the system to respond to changes in usage, i.e. keeping the generators and loads matched at all times. Combined cycle generating units have the electrical characteristics to provide this fast response balancing in real time. The system frequency, required to be maintained at 60 Hz in the US grid, is an active measure of this balance. When there are changes to the generation/load balance, as when wind speeds drop or a large industrial load comes online, the frequency drops if there is insufficient regulation capability on the system. This is another aspect of the dynamic stability of the system, typically in a longer timeframe.

The National Academies of Sciences, Engineering, and Medicine observed that large-scale interconnected generating units have two significant advantages:

(1) *Reliability*. By interconnecting hundreds or thousands of large generators in a network of high-voltage transmission lines, the failure of a single generator or transmission line is usually inconsequential, and

(2) *Economics*. By being part of an interconnected grid, electric utilities can take advantage of variations in the electric load levels and differing generation costs to buy and sell electricity across the interconnect. This provides incentive to operate the transmission grid so as to maximize the amount of electric power that can be transmitted.

However, large interconnections also have the undesirable side effect that problems in one part of the grid can rapidly propagate across a wide region, resulting in the potential for large-scale blackouts such as occurred in the Eastern Interconnection on August 14, 2003. Hence there is a need to optimally plan and operate what amounts to a giant electric circuit so as to maximize the benefits while minimizing the risks.[14]

D. Planning Overview

The MISO long-term planning process, defined in Attachment FF to the MISO Tariff, is an eighteen month, overlapping process through which annual transmission expansion plans are developed and approved. This process is made up of three distinct long term planning efforts: Reliability Planning, Economic Planning and Resource Adequacy. MISO has recognized that its present planning processes require update to recognize the increasing levels of renewable resources on the grid, as well as increasing levels of energy efficiency, demand response, and distributed energy resources (DER). We discuss this further in Part III below.

1. Reliability Planning

As a NERC registered Transmission Planner, the Company works jointly with MISO and neighboring utilities to develop long term transmission plan to ensure a reliable transmission system. This is accomplished through several local and regional planning efforts, as follows:

[14] National Academies of Sciences, Engineering, and Medicine 2016. *Analytic Research Foundations for the Next-Generation Electric Grid*. Washington, DC: The National Academies Press, page 10. https://doi.org/10.17226/21919

Biennial Transmission Projects Report. In compliance with Minn. Stat. § 216B.2425, the Company participates in the Biennial Transmission Project Report efforts with other Transmission Owners. Starting in 2001, this effort completed its ninth iteration with the 2017 report. In 2003, the Minnesota Public Utilities Commission established six transmission planning zones across the state in 2003. Those six transmission planning zones are the Northwest Zone, the Northeast Zone, the West Central Zone, the Twin Cities Zone, the Southwest Zone, and the Southeast Zone. The Biennial Report identifies the present and reasonably foreseeable transmission "inadequacies" in the transmission system that exist in each of these six transmission planning zones. With information about each inadequacy identified provided. The Biennial Report also provides an update on the status of the utilities' efforts to meet state Renewable Energy Standard deadlines. We summarize our most recent Biennial Report in Appendix I: Supporting Infrastructure: Transmission & Distribution.

NERC Transmission Planner Registration. To satisfy the obligations associated with the Transmission Planner registration with NERC, the Company also participates in the annual Minnesota Transmission Assessment and Compliance Team (MNTACT) to perform annual long-term transmission planning studies in accordance with federal, state and local transmission reliability standards and criteria. The Company utilizes the results of these analyses to inform the regional planning efforts undertaken by MISO.

MISO Membership and FERC Order Obligations. In accordance with the obligations of MISO membership and FERC Orders 890 and 1000, the Company also participates in regional long-term planning efforts facilitated by MISO. While these efforts replicate work already undertaken by the Company in other planning efforts, participation in MISO reliability planning process provides an open and transparent planning process that allows input and discussion amongst a wide range of stakeholder and public advocacy groups. Based on the requirements of the MISO Transmission Owners agreement, MISO approval is also required for inclusion of new transmission facilities under MISO's functional control.

2. *Economic Planning*

In addition to the long-term transmission reliability analyses, participation in the MISO planning processes also includes an annual economic-based planning analysis to identify inefficiencies in the transmission system leading to less than ideal wholesale electricity market dispatch. Starting with a stakeholder-approved set of wide-ranging future scenarios, this analysis first identifies these areas of system inefficiencies – after which, stakeholder submitted solutions are analyzed to determine if there is a cost effective solution. The Huntley–Wilmarth 345 kV Project is an example of a cost effective solution analyzed to develop the most cost-effective market possible.[15]

3. *Resource Adequacy*

The Resource Adequacy process facilitated through the MISO process is designed to ensure enough capacity is available to meet the needs of all consumers in the MISO footprint during all time frames and at just, reasonable rates. Although the responsibility for resource adequacy, MISO's process provides support in their members individual resource adequacy efforts and provide forums to increase transparency into these more localized efforts. These support efforts include calculation of the Planning Reserve Margin, which defines the level of reserve generation capacity needed to ensure an adequacy supply of energy based on probabilistic analyses. Also facilitated in this process is the Deliverables to the Planning Resource Auction, including peak forecasted demand and Import/Export limitations for the following year.

Through the participation and outcomes of the different planning processes the Company participates in, several vital pieces of the long-term planning picture are analyzed and updated on an annual basis. This enables development of the most cost effective and efficient solutions and direction in the long-term use of the transmission system at a local, regional and interconnection-wide level.

4. *Black Start*

At a high level, a Black Start Plan specifies the process we use to restore our grid to full operation without relying on the external transmission network, following a full- or partial-black out. Black Start Plans are required by NERC, developed in concert with neighboring utilities, and are subject to review and approval by MISO. Developing such a plan involves developing models, strategies and procedures to configure the system such that one or more generators can be brought online – and at the same time, picking-up sufficient customer load to satisfy the generator's minimum requirements for stability. The longer the system is down, the harder it is to restore, so we work to determine the most efficient paths possible.[16]

The restoration is initiated under the instruction of the Transmission Operator and

[15] *See* Docket No. E002, ET6675/CN-17-184 or www.huntleywilmarth.com)
[16] The longer the system is down, equipment and facilities cool. Additional impacts include effects such as the fact that substation batteries will only keep the substations operational for a limited time. If the substation batteries deplete, we cannot easily isolate or energize the substation.

proceeds under the general guidance of a site specific restoration plan. Not all power generation units have, or are required to have, this Black Start capability. Black Start-capable generating units have specific configurations, additional on-site emergency generators and must be held to the highest reliability standards to ensure responsiveness in the face of an emergency.

III. THE GRID IS EVOLVING

A. The Introduction of Energy Markets

The electrical transmission system has moved from being a locally-owned and operated power system that was weakly tied to one another through high-voltage transmission lines to a regional model focused on efficiency and reliability.

Through the incorporation and membership in the regional RTOs, locally-owned transmission facilities have been turned over to the function control of regional grid operators to participate in open and effective wholesale energy markets. Through the creation and operations of the wholesale electrical markets, MISO has effectively delivered a more efficient system. Where the old power pool had reserve requirements up to and exceeding 25 percent of the utility's demand, MISO – using modern modeling and markets operations – has been able to significantly reduce spinning reserve requirements (the most costly reserve requirement) for the region. In addition to the more efficient use of existing resources, this construct has allowed for more of the older, less efficient power plants to retire while maintaining system reliability.

MISO's open access Generator Interconnection Queue allows for new generation that has requested interconnection service to be studied for inclusion into the transmission system. This process ensures that there is a fair and transparent process for all generators to have unbiased access to the regions transmission system and allows competitive participation in the wholesale energy market. MISO's Wholesale Energy Market allows for the region to have the lowest cost generation mix available at the time while maintaining system reliability through a process referred to as a Security Constrained Economic Dispatch (SCED). One key aspect of market participation enables each generator owner to bid into the market at competitive prices ensuring the lowest wholesale energy cost for the customers across the MISO footprint. We discuss the current status and challenges with the MISO interconnection queue that are creating uncertainty for planning purposes in Appendix I: Supporting Infrastructure: Transmission & Distribution.

B. Shifting Resource Types and Mix

One major benefit realized through the implementation of an open and competitive wholesale energy market is the ability for zero-emission and renewable sources of generation being allowed to compete on a fair and equitable basis with more traditional forms of generation. Due to this, renewable development has grown in the MISO region largely through expansion of wind resources to-date – with significant growth in solar expected. The current significant wind resources are primarily in southwest Minnesota and northern Iowa, but over time have also expanded to almost every part of the MISO system.

1. Rapid Increase in Renewables

In the year 2000, there were approximately 2,500 MW of wind on the transmission system across the entire United States. Today, there is over 18,000 MW of wind just in the MISO footprint – with solar power now also being added to the mix. The initial drive for renewables was created through the development of public policy initiatives that allowed for tax credits to make the renewables more cost competitive against the more traditional coal and nuclear prices and set renewable energy goals for utilities subject to those local regulations. More recently, renewable forms of generation resources have been selected purely as the most economic resources. In addition to the more competitive renewable costs, public opinion has driven the push for a more carbon-neutral set of generating resources.

Since the first wind turbines were installed, the price for wind has dropped dramatically. As manufacturing processes have improved, and supply chain efficiencies incorporated, some economies of scale were realized, driving lower costs for new wind turbines. In addition to solely reducing installation costs, improvements in the power electronics have improved the performance of the new wind turbines to help with system reliability. Solar from both small and large utility-scale resources are increasingly part of the resource mix. Public policies for new solar coupled with dropping prices and tax incentives are helping to drive the increase. Solar has the added benefit of its peak output being closely correlated with peak demand.

Energy storage is just starting to be used in utility-scale settings, with processes only just now being developed to incorporate these technologies into long-term planning efforts. There are several energy storage methods that are being studied for commercial applications, one of which is battery storage. Battery storage is already being tested and incorporated in some electric markets around the world. Battery storage offers the ability to store excess power created that cannot reach customers at the time of generation, and release that stored energy when the system demands it.

Batteries have several benefits, including the ability to store power for the purposes of helping with grid stability through power electronics and small scale power injections and withdrawals as well as shifting energy production to hours with high demand. While batteries will play a roll in our carbon reduction goals, current technologies in the early stages of commercial use, and because of this, have not yet incorporated manufacturing and supply chain efficiencies that have made wind and solar generation resources more cost competitive.

2. The Changing Generation Mix is Putting Pressure on Area Reserve Requirements

In the wake of the electrical system transforming from local power pools to regional markets that include increasing levels of non-traditional and renewable resources, there has been an increase in the rate of retirements of aging baseload generating units. Most of the generation replacing these traditional, dispatchable units are from intermittent resources such as wind and solar. Because these intermittent resources are dependent on fuel availability (wind blowing or sun shining), their replacement of retired dispatchable units is putting extra pressure on the reserve requirements for the region, since wind and solar cannot be counted on at all times. While MISO recognizes this and is studying issues related to high renewable penetrations in its RIIA study, its planning construct has not yet adapted to recognize this reality. We discuss the RIIA study below, and in Appendix J2, along with our development of a Reliability Requirement as a bridge until the MISO planning construct changes.

In addition, most of the best locations to develop cost-effective wind and solar resources are located away, and in some cases, far away from populated areas and thus load centers. This requires a robust network of large bulk electric transmission lines to bring the renewable power to the load, which means that significant transmission development will be needed to support increasing levels of renewables. However, the more transmission infrastructure between the renewable resources and the load centers, the greater the risk that those resources will be unavailable to the load centers when needed. This is because long transmission line(s) are more likely than a short line to be impacted by severe weather or some other event that along the line – making it unavailable to deliver the energy from the resource(s). This reality lowers the accreditation of the renewable resource(s) – and increases the reserve requirements for the area.

3. Growing Penetrations of Distributed Energy Resources

In addition to baseload retirements and the rapid expansion of renewable generation resources, growing reliance on DER, including DR, introduce strains to the transmission system that have not been historically encountered. While both of these resources represent important and useful tools in planning for a reliable and cost-effective power system, they have indirect and sometimes counter-intuitive impacts on the transmission system. In levels that do not produce what would be considered reverse flows, resources originating on the distribution system and flowing onto the transmission system look similar to a localized reduction in demand on the transmission system. From a high level, this should only result in a reduction in the generation required to meet the demand. However, because of low market offer prices for renewable resources in the MISO market, when this localized reduction in demand occurs, it serves to increase long distance transfers on the transmission system, causing strain on those facilities.

4. Planning Impacts of the Shifting Resource Mix

A part of the MISO planning processes is an annual analysis of reserve levels. Planning reserves are the margin by which resources exceed expected customer demand. MISO's Resource Adequacy process establishes the margin by which each utility's resources are required to exceed demand in order to cover potential uncertainty in the availability of resources or level of demand.[17]

Reserve analysis is also incorporated into the NERC Long-Term Reliability Assessment (LTRA), which is an annual report highlighting national and regional trends and potential risks over a 10-year assessment period. While it is fairly common for a planning region to drop below the reference reserve margin levels in later years of the assessment period, the 2018 LTRA report specifically calls out MISO as one of three regions that are projected to drop below their reference reserve margin levels earlier than normally encountered – specifically by the year 2023.[18]

This report indicates that inclusion of generation with high likelihood of being incorporated into the MISO system (known as Tier 2 resources in the LTRA) would likely allow for the MISO footprint to preserve system reliability.[19] That being said, there has been an unprecedented rate of baseload generation retirements announced, but that are not yet taken into account in this analysis. There is also uncertainty regarding future capacity accreditation levels for renewable resources, particularly, as

[17] Factors affecting availability and demand include: Planned maintenance, Unplanned or forced outages of generating facilities, Deratings in resource capabilities, Variations in weather, and Load forecasting uncertainty.

[18] https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

[19] NERC defines Tier 2 resources as being in the interconnection queue and having a signed/approved completion of a feasibility study, signed/approved completion of a system impact study, signed/approved completion of a facilities study, requested Interconnection Service Agreement, or is included in an integrated resource plan or under a regulatory environment that mandates a resource adequacy requirement (Applies to RTOs/ISOs).

well as the potential for increased reserve requirements. This all combines to cast doubt on whether those Tier 2 resources relied upon in the LTRA alone are sufficient to provide adequate reserves to mitigate the identified risk. Further, when considering the findings from NERC's *Generator Retirement Scenario Special Study*, we believe there is an increased level of risk that baseload generation retirement requests may result in system support resource (SSR) (or something similar) designations[20] – as was the case with our Sherco Units 1 and 2 MISO Attachment Y2 study, discussed in our last Resource Plan.

C. Early Studies Did Not Fully Contemplate the Level of Change Underway

When the wind generation was first injecting energy into the system, it was in small amounts that were able to utilize the existing bulk and non-bulk AC power system. The existing AC power system was developed to deliver energy to customers from large centralized power stations usually located next to areas of the highest customer demand. As more and more renewables were added to the system the AC grid has had to morph into more a hybrid system that shifts power back and forth depending on the generation pattern for the day.

Early studies done on the system did not anticipate the impact that rapid adoption of renewables would have on the existing system. These studies also tended to underestimate the early retirement of existing resources that provide important support to the system. We discuss these early studies below.

1. Upper Midwest Transmission Development Initiative

The Upper Midwest Transmission Development Initiative (UMTDI) was developed in 2008 as a coordination effort between the States of Iowa, Minnesota, North Dakota, South Dakota and Wisconsin tasked with accomplishing two major tasks: (1) Establish a plan that will guide and encourage the construction of interstate transmission lines to serve the upper Midwest region's commitment to cost-effective renewable generation while maintaining reliability, and (2) Develop an equitable cost-sharing methodology for new transmission facilities.

A final report from the initiative provided five high-level areas that represented barriers to development of transmission to enable renewable generation:

- *The need for certainty in regional planning for transmission.* Developers and regulators

[20] In MISO, in some cases, a generator may be designated as a System Support Resource (SSR), which is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available.

need to know what the rules are for transmission planning. In the absence of such certainty, development stalls and the potential for inaccurate decision-making arises.

- *The right balance between remote and local renewable generation.* There is a need to cost effectively balance highly efficient renewable energy resources far from customers with local renewable energy resources closer to population centers.
- *Large transmission projects are expensive and will impact electric rates.* Billions of dollars of transmission investment may be necessary. Minimizing these costs through sound planning is critical to ensure that projects get built cost effectively.
- *Large transmission projects can cause large land-use impacts.* Transmission projects require the acquisition of sizeable tracts of land for right-of-way easements. Such acquisitions garner strong reactions from landowners and neighbors and the public at large. While recognizing that each state has the ultimate siting authority for transmission lines
- *Cost allocation for the needed transmission is contentious.* Arguably the largest hurdle to new construction is how the costs get distributed. In the absence of an equitable formula, projects will not get built, or parties not benefiting from the projects will end up paying for them.

Due to the significant overlap between the UMTDI effort and Regional Generation Outlet Study (RGOS) and Regional Expansion Criteria and Benefit Task Force being performed by MISO at the same time, the group transitioned its efforts to focus on advocacy in those regional efforts.

2. MISO Regional Generation Outlet Study

Beginning in 2008, MISO initiated the RGOS in response to the passing of Renewable Portfolio Standards by several of the MISO member states mandating the expansion of renewable energy resources in state utility portfolios. The purpose of this study was to determine a best fit solution in the form of a transmission overlay encompassing all MISO states – premised on a distributed set of wind zones – each with varying capacity factors and distances from load.

Despite this early and comprehensive study work, the unprecedented growth of renewable generation and the earlier than expected retirement of baseload generation have resulted in impacts to the current system that have far exceeded what was projected in the RGOS analyses.

3. *Regional Expansion Criteria and Benefits*

Concurrently with the development of the RGOS overlays, the MISO stakeholders developed the first significant round of cost allocation principles for transmission projects. This provided a formal process for assigning cost responsibility for transmission upgrades to in a way that is roughly commensurate with beneficiaries.

4. *Minnesota Renewable Energy Integration and Transmission Study*

In 2013, the Minnesota Renewable Energy Integration and Transmission Study (MRITS) was initiated to build upon prior work with respect to the integration of renewable energy, specifically looking at a potential increase of the Minnesota Renewable Energy Standard (RES) to 40 percent by 2030, and higher levels beyond that timeframe. The purpose of this study was to determine the reliability impacts of increase variable generation development as well as determining associated cost impacts.

The study consisted of three core analyses:

- *Power flow analysis* was utilized to develop a conceptual transmission plan, including transmission expansion required for both interconnection of additional variable resources as well as required expansion to allow the energy from those resources to reach the wider region.
- *Dynamics analysis* was utilized to determine issues with system stability and system strength.
- *Production Cost analysis* to determine more operationally focused challenges to the integration of significant levels of variable resources.

The results of this study stated that 40 percent of Minnesota's retail electricity sales can be reliably accommodate with upgrades to the existing system at the time of the analysis.

However, while there were several important pieces of information gleaned from the MRITS study, the unprecedented expansion of variable generation that has occurred combined with the retirement of several large baseload generators that was not fully anticipated at the time of this study, has made the assumptions that went into this analysis outdated – and as such, the full results cannot be directly applied to today's transmission system.

D. MISO Processes Must Further Evolve

To accommodate the rapid expansion of renewable generation resources in the region, MISO's generation interconnection process has undergone several process improvements, but does not yet fully reflect the state of the evolving grid. As additional variable generation replaces firm dispatchable resources, issues such as weak signal strength and system instability become more likely. Current interconnection processes study only two conditions (summer/peak and shoulder); current resource adequacy processes assign fixed annual capacity values to variable resources based on their *average* contribution to the grid. These practices do not properly assess other grid conditions for potential reliability impacts – nor do they recognize the portion of time that variable resources will provide less or no energy and capacity to serve customers.

When a large batch of inverter-based generation performs outside of what is expected, models typically show that the system can survive adverse conditions. But in 2016, the Australia power system experienced storm damage that forced several transmission lines to open. The wind farms that were being relied upon on at that time were not able to survive multiple ride-through capability cycles, and started to trip offline – resulting in a large-scale power outage in southern Australia. While there are standards and practices in place in the Eastern Interconnection, MISO and Minnesota transmission systems to help avoid this same scenario, the rapid escalation of renewable resources and the earlier than expected retirement of baseload generation places a greater strain on the transmission system to deliver more remote sources of generation, and increases the likelihood of events similar to the Australia power outage occurring on the local transmission system.

MISO's early generation queue was done in order of requests. While this process allowed for concrete identification of issues caused by individual generator interconnection requests, it was a slow and tedious process of study after study, followed by restudies when the inevitable request withdrawal happened.

As the rapid development of renewables continued, MISO shifted to group studies process to help deal with the volume of requests. This greatly increased the ability of the MISO process to analyze larger sets of interconnection requests, but failed to address the issues of restudies, queue parking and withdrawals. The most recent iteration of generator interconnection process changes incorporated elements to remove the ability to suspend requests, set higher hurdles for continuation through the process and incent early withdrawals of projects that are unable to complete the interconnection process at that time. While these studies are sufficient to determine network upgrades to allow interconnection of the requested facilities, they are performed with models of the existing system *at the time* of the study, which does not include future generation retirements, unless they are formally-confirmed.

Current generator interconnection studies are based on two conditions, summer and shoulder, and determine the system improvements needed for each study group. This is to represent two of the most strenuous scenarios for the transmission system – one during peak customer demand, in which all resources are employed to meet that demand – and the other, a scenario representing lower customer demand and high renewable generation output, leading to high levels of power transfers across the transmission system. Even though these two strenuous scenarios are analyzed, there are system conditions that exist that put a large strain on the system and are not studied as part of the generation interconnection process.

For example, MISO experienced a low wind day July 29, 2018, where wind produced below the accredited levels for more than 100 consecutive hours. Another example is during the most recent polar vortex when the vast majority of wind turbines shut down due to extreme cold temperatures, and output dropped sooner than the forecast had predicted. As a result, firm dispatchable resources were needed to fill the gap left by the forecast error and lack of wind. We discuss these case study days further in conjunction with the Reliability Requirement in Appendix J2.

As the grid further evolves to include increasing levels of renewable resources, there will be an increased need to identify impacts and propose solutions that ensure reliable delivery of energy every hour of every day, rather than relying on limited snapshots. These events that limit the availability of resources below what is expected are extreme and may represent only a small portion of potential operating conditions, but maintaining a reliable system through *all conditions* will be important in the changing future.

IV. XCEL ENERGY BASELOAD GENERATING RESOURCES STUDY

Order Point No. 14(a) of the Commission's January 11, 2017 Order in Docket No. E002/RP-15-21 required Company in its next Resource Plan to study the future of its baseload generating resources, and describe its plans and possible scenarios for cost-effective and orderly retirement of its aging baseload fleet, including Sherco, King, Monticello, and Prairie Island. In this section, we outline the four-pronged approach we took to conduct this analysis.

A. Overview

Aging baseload generator retirements and increasing levels of renewable generation on the grid are trends underway in the industry that are not yet fully understood. The current transmission system is developed, operated and maintained in accordance with several sets of standards and processes to ensure the safe, reliable and efficient delivery of power. Some of these include standards and recommendations from the Institute of Electrical and Electronics Engineers (IEEE), the National Electric Safety Code (NESC), the Nation Electric Code (NEC) and countless industry standards referred to as "Good Utility Practice." One of the most impactful to the development, planning and operation of the transmission system is the standards set by NERC, which through the authority of FERC, has the ability to enforce the established NERC standards under penalty of fines. NERC standards touch on everything from system modeling requirements to system operations, including both physical and cyber security standards. Embedded in these standards are local system practices and protocols from which the standards are formulated.

While these standards and protocols have worked well in the past, the changes underway on the grid are introducing new challenges. This requires additional foresight in planning processes to ensure reliable delivery of power to customers utilizing a cost-effective transmission system. Although the trend toward high penetration levels of intermittent generation has been commonplace for several years, the industry is just starting to analyze the impacts of these changes from a holistic point of view. MISO and individual utility planning and study practices will need to adapt to ensure we continue to have a resilient system and strong customer reliability.

That said, the work that we have done with this Baseload Study provides helpful insights into this complex intersection of the future grid. Further studies and an orderly plan will be key to ensuring reliability and resilience through the clean energy transition we envision for our system.

B. Approach

The NSP System has been developed over the past 100 years to serve the growing area, and is constantly being analyzed to ensure optimal and reliable power delivery. We have a great deal of experience both in studying the existing grid and operating it in many varying conditions (during high load, low load, high transfers, low transfers, storm conditions, outages or equipment). However, as noted above, planning and study practices have not fully adapted to trends underway. We believe however, that our technical and economic approach combined with relevant industry insights in this Study provides helpful insights to an orderly and cost-effective retirement of our current baseload generating units.

The components of our Study are as follows:

- **Midcontinent Integrated Systems Operator (MISO) Attachment Y2 preliminary retirement studies**, which assessed various single Unit and combined Unit retirement scenarios for thermal and voltage concerns,
- **Xcel Energy Transmission Reliability studies**, which examined system stability and response impacts associated with baseload generating resource changes on the NSP System and on neighboring systems,
- **Industry insights**, including the North American Electric Reliability Corporation (NERC) *Generator Retirement Scenario Special Study* and the MISO *Renewable Integration Impact Analysis* (RIIA), which provide important insights into the combined effects of baseload generator retirements in a region and grid impacts at increasing levels of renewables penetration, and
- **A focused Strategist analysis**, which examined the economic implications of various Unit and combined Unit retirements at different points in time.

When performing technical studies, we simulate a number of varied conditions that can consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid and search for places where the system might overload or fail, assuming specific circumstances. While these studies are essential and provide important insights, our decades of operating and studying the existing system also provides valuable insights and perspective toward assessing potential impacts from NSP System grid changes. We have incorporated this experience into our analysis of impacts. We also supplemented our technical study efforts with relevant industry initiatives that examine the compound impacts of aging baseload retirements and increasing levels of renewable generation – similar to the issues facing the NSP System.

The MISO Y2 and our Reliability Studies identify grid impacts and potential transmission mitigations necessary to resolve the respective issues the studies identified. MISO performed its Y2 Studies in accordance with their Business Practice Manuals, which generally focus on thermal and voltage issues.[21] We used the MISO planning level estimated mitigation costs from the Y2 studies as an input to our Strategist modeling of the baseload unit retirements. While these may not be the final mitigations, they provide a proxy of potential costs to inform the economic aspect of our Baseload Study. Our technical studies supplemented the MISO analysis to examine traditional NERC reliability measures such as system stability and response.

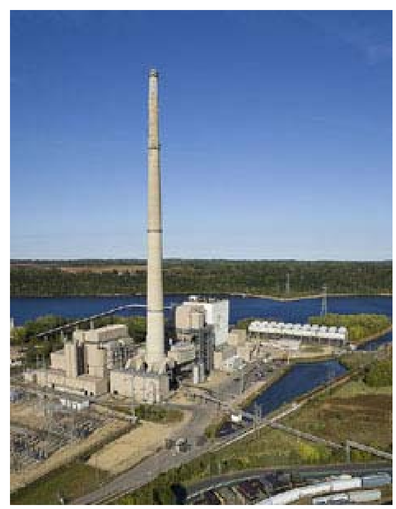
[21] *See* MISO Business Practice Manual BPM-020 at: https://www.misoenergy.org/Library/BusinessPracticesManuals/Pages/BusinessPracticesManuals.aspx

This is an important complement to the MISO Y2 studies to provide a more robust look at potential impacts from baseload changes on the NSP system and regional MISO grid.

All studies are essentially an attempt to predict what is going to happen in the future – and the conditions and underlying assumptions of a dynamic system are subject to change. These technical studies used the best information available at the time they were initiated. However, while the studies provide important insights, there are inherent limitations in any study effort. Technical studies simulating the removal/ absence of a generating unit(s) on the grid can only practicably analyze potential impacts with a point-in-time model in a limited set of grid conditions (i.e., peak, shoulder, etc.). Therefore, while they provide important insights for the limited number of scenarios studied, it is important to supplement the technical studies with industry insights and engineering judgement. We have attempted to offset these limitations by taking a multi-faceted approach to our Study, and note that further studies more proximate in time to the potential retirement dates will be necessary to determine actual impacts and actual mitigations.

C. Xcel Energy Baseload Resources Fleet

1. A. S. King



This plant was named in honor of Allen S. King, former president and chairman of Northern States Power Company, a predecessor to Xcel Energy. The King plant underwent a significant rehabilitation from 2004-2007 as part of Xcel Energy's Metro Emissions Reduction Project (MERP).

Key Facts

- *Power Production Capability:* 598 megawatts
- *Commercial Operation:* 1968
- *Generation Type:* Coal
- *Location:* Oak Park Heights, Minnesota, on the St. Croix River

In addition to generating electricity, A. S. King supplies hot water to neighboring Andersen Windows, a large window manufacturer. Located on the border of Minnesota and Wisconsin, King also provides stability to the Upper Midwest transmission grid.

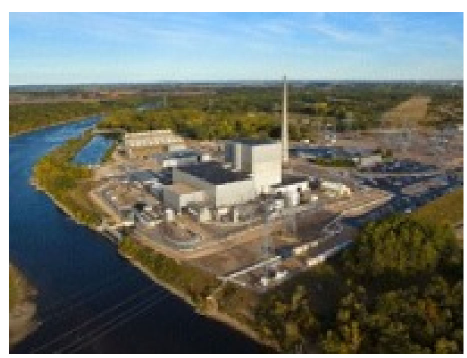
2. *Sherburne County (Sherco) Generating Station*

The Sherco plant is comprised of three generating Units with a total nameplate capacity of approximately 2,400 MW. Sherco is the largest plant in the Company's fleet in terms of square feet, steam production, and power generation capability. Units 1 and 2 are scheduled to retire in 2026 and 2023, respectively. This Resource Plan proposes to retire Unit 3 in 2030. Unit 3 is 41 percent owned by Southern Minnesota Municipal Power Agency, composed of municipal power companies operating on a cooperative basis.

<u>Key facts</u>

- Power Production Capability: 2,457 MW
  - Unit 1 – 765 MW
  - Unit 2 – 765 MW
  - Unit 3 – 927 MW
- *Commercial Operation:* Unit 1 - 1976; Unit 2- 1977; Unit 3 - 1987
- Generation Type: Steam Turbine
- *Location:* Becker, Minnesota, 45 miles northwest of the Twin Cities, on the Mississippi River

3. *Monticello Nuclear Generating Station*



The Monticello facility is among Xcel Energy's lowest-cost sources of electric generation on a per-megawatt basis and produces virtually no greenhouse gas emissions. As a base load 'always-on' plant, it runs essentially 24 hours a day, 7 days a week, except during refueling outages, which occur about every two years. Monti is a boiling water reactor plant is located on a 215-acre site 40 miles northwest of the Twin Cities. The plant generates approximately 10 percent of the electricity used by Xcel Energy's customers in the Upper Midwest.

Key Facts

- *Power Production Capability:* 671 Megawatts
- *Fuel Type:* Nuclear
- *Location:* Monticello, Minnesota

The plant received a 40-year operating license from the federal Nuclear Regulatory Commission in 1970, and it began commercial operation in 1971. In 2006, the NRC renewed the Monticello plant's license for 20 years, which allows operations until 2030. This Resource Plan proposes to extend the operation of the Monticello plant an additional 10 years, which will require a license extension from the NRC.

4. Prairie Island Nuclear Generating Station

The two pressurized water reactors at the Prairie Island facility generate about 20 percent of the electricity used by Xcel Energy's customers in the Upper Midwest. Prairie Island is among our lowest-cost sources of generation on a per megawatt-hour basis, and does not produce any greenhouse gas emissions. The plant runs essentially 24 hours a day, seven days per week, except during refueling outages, which occur approximately every 18 months and last about four to six weeks. The plant is about 40 miles southeast of Minneapolis-St. Paul and generates enough electricity to power about 1 million homes.

Key Facts

- *Power Production Capability:* 1,186 megawatts (593 MW per Unit)
- *Fuel Type:* Nuclear
- *Location:* Red Wing, Minnesota

The Unit 1 reactor began operating in December 1973 and the Unit 2 reactor in December 1974. The Nuclear Regulatory Commission first licensed the reactors for 40 years of operation and extended those licenses for an additional 20 years, until 2033 and 2034.

The Prairie Island and Monticello nuclear generating plants help Xcel Energy avoid producing hundreds of millions of tons of greenhouse gases or emissions. The plants avoid 13 million tons of carbon dioxide annually compared to fossil fuel plants, the equivalent of removing 2 million cars from the road each year.

D. Industry Studies and Outlook

We also considered industry trends and relevant studies on the effects of aging baseload units and the cumulative effects of higher renewables penetrations. Two of these studies were the MISO *Renewable Integration Impact Assessment* (RIIA) study, which is ongoing, and the December 2018 NERC *Generator Retirement Scenario Special Reliability Assessment.*

1. Industry Study – MISO Renewable Integration Impact Assessment

In 2017, MISO initiated a detailed exploration of assumptions regarding the way the electrical grid will work in the future in light the "profound" change in the types of generating resources across its operating area and the implications that such a shift means for long-standing power system design and operational practices. Under current practices, renewable resources are relied on mostly for their energy production attributes, but as they continue to replace existing assets, they will be expected to increase their contribution to grid reliability.

Given the current structure (physical infrastructure, operational practices, regulations, etc.) of the electric system in MISO and beyond, there are limitations on the maximum penetration of renewable energy. The complexity of overcoming these limitations are dependent on the types and distribution of renewable resources, the current layout of existing assets, and the actions of neighboring regions. Because the exact points of these limitations are not yet known, a framework is needed to examine renewable integration over a wide range of penetration levels, starting with the system we have today and examining penetration levels up to very high percentages of annual energy. This framework, when completed, will reflect and inform the conversations that MISO and other entities within the electricity sector have been having on the impacts of the evolving resource mix on the BES.

The study has three focus areas: (1) Resource Adequacy, or the ability to maintain the Planning Reserve Margin; (2) Energy Adequacy, or the ability to operate within generator limits such as ramp rates, min/max capacity, etc., transmission limits/ratings, and system limits such as energy balance and operating reserves; and (3) Operating Reliability, or the ability to operate the system within acceptable voltage and thermal limits and the ability to maintain stable frequency and voltage, and meet system performance requirements. The study is being conducted in phases, with each phase examining increased levels renewable penetration. Phase II was completed in Q1 2019, and examined region-wide renewable penetrations in the 40-50 percent range.

This is being accomplished by identifying "milestones" or inflection points of integration complexity, initially identified through four modules:

- *Operational Adequacy*. Simulation of the Day-Ahead (DA) and Real-Time (RT) to examine the Ancillary Services Market (ASM), including aspects such as ramping, emergency/dump energy, reserve requirements, congestion, etc..
- *Transmission Adequacy*. Analysis of the power system utilizing more traditional power system analyses. This analysis examines peak demand, shoulder demand and low demand scenarios to assess the ability of the transmission system at each milestone.
- *System Stability*. Analysis of the very short term capabilities of the transmission system to maintain system stability. This analysis utilizes scenarios similar to the Transmission Adequacy module, but focuses on the sub-second to multiple second response timeframe to determine the ability to maintain voltage and transient stability and ensure adequate system response capability is available.
- *Resource Adequacy Limitations*. Determination of the impacts to resource reserve margins and load carrying capability of intermittent resources and interdependencies between resource types.

These modules are being applied through three Phases that study these impacts at increasing levels of renewable resources.

a. Key Takeaways To-Date

One of MISO's key conclusions to-date is that integration complexity increases dramatically between 30 percent and 40 percent. At a 40 percent MISO-wide renewables penetration level, curtailments are encountered during almost all non-summer days, reaching nearly 7,000 GWh of curtailments in the worst month of the base case at this level. Other interim conclusions relevant to our study of an orderly cost-effective transition of our baseload units thus far include:

- Renewable integration complexity increases sharply from 30 percent to 40 percent penetration. Currently synchronous baseload units provide necessary services to the grid that mitigate the impacts of the inherent variability of renewable generation.
- As wind and solar penetration increases, its contribution to peak load conditions reduces because the risk of losing load compresses into a smaller number of hours and shifts to later in the day (from 3:00 p.m. to 6:00 p.m). As a result, the available energy from wind and solar during high risk hours

decreases, and the marginal contribution of renewables reaches a plateau. We discuss this further in Part IV.D below, and in conjunction with the Reliability Requirement we developed for this Resource Plan, discussed in Appendix J2. This issue is both a current and future risk to system resilience and reliability that is not currently addressed in the MISO planning construct.

- As renewable penetration grows, renewable curtailment becomes increasingly significant; enhanced transmission reduces curtailment. With increased levels of renewables inevitable to achieve significant carbon reductions, substantial transmission development will be necessary.
- As renewable penetration increases, the number of thermal units online increases during off-peak hours despite a decrease in average output – and fewer thermal units are operating at their minimum stable level.
- Thermal overloads and voltage violations increase as penetration levels increase, with solution complexity (cost of the transmission fixes) also increasing with penetration level. North Dakota and parts of Minnesota start to show severe thermal and short circuit issues due to vast amount of wind resources sited in those locations and relatively limited transmission capacity.
- Diversity of technologies and geography improves the ability of renewables to meet load.
- Overall, the 40 percent scenario increased the instances of dynamic stability issues, operational stressors, and resource adequacy requirement increases.

In observing that the level of renewable resources in the MISO footprint is growing at a rate of about 1.5 GW per year since being nearly non-existent in 2005, MISO acknowledged challenges along the way – and is taking action to evaluate the impacts of renewable resources growing to even higher levels over the long-term. As described by MISO, its RIIA assessment will give MISO and its stakeholders specific areas around which to focus effort and help inform the sequencing of actions required to manage certain renewable penetration levels. The assessment will illustrate specific areas of system weakness, show when those weaknesses could become problematic and identify potential means to address them – and will seek to facilitate a broader conversation about renewable integration impacts on the reliability of the electric system.[22] The study is now continuing on to Phase III.

[22] *See* https://www.misoenergy.org/planning/policy-studies/Renewable-integration-impact-assessment/#t=10&p=0&s=&sd=

2. *Industry Study – NERC Special Reliability Assessment – Generation Retirement Scenario*

Below we summarize a recent special report from NERC that implies there may be potential for delay or cancellation of announced retirements due to insufficient system support services provided by synchronous generation being available in some regions.

NERC published a Generation Retirement Scenario Special Reliability Assessment December 18, 2018 as part of its ongoing efforts to assess the potential implications of the changing generation resource mix on the reliability of the North American BES. In initiating this special assessment NERC observed that the BES is undergoing a significant transformation, marked by growth in new natural gas, wind, and solar resources replacing retiring fossil-fired and nuclear generating resources. The drivers underlying this shift that NERC cited include federal and state policies, continued low natural gas prices, wholesale market forces, customer preference, and low and improving technology costs.

NERC also observed that managing generator retirements and the transition to replacement resources is a complex process. The report characterizes the changes currently underway with the generation resource mix as "revolutionary," and observes that the changes alter the operating characteristics and constraints of the BES. The report stresses that these changing characteristics must be well understood and incorporated into planning to assure continued reliability.[23]

NERC's key conclusion is that the generator retirements that are occurring disproportionately affect large baseload, solid-fuel generation (coal and nuclear). If these retirements happen faster than the system can respond with replacement generation, including any necessary transmission facilities or replacement fuel infrastructure, significant reliability problems could occur. Resource planners at all levels should use their full suite of tools to manage the pace of retirements and ensure replacement infrastructure can be developed and placed in service. Ensuring reliability throughout a significant retirement transition will likely include construction of new transmission and fuel infrastructure

This NERC study underscores the importance of taking a measured approach to baseload unit retirement that includes thorough examination of potential reliability implications. This also supports our belief that appropriate analysis may require supplemental study beyond the studies prescribed in present protocols.

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[23] Executive Summary, NERC Special Reliability Assessment: Generation Retirement Scenario (December 18, 2018).

As part of its oversight and governance activities, NERC also conducts an annual reserve margin analysis across all system operators in North America in a report called the LTRA, discussed earlier in this Study. The 2018 LTRA indicated that MISO is one of three regions that are projected to drop below their reference reserve margin levels by the year 2023, unless certain measures are taken.[24] This report indicates that inclusion of Tier 2 resources (those that are in more advanced stages of planning but not yet under construction) would likely allow for the MISO footprint to preserve system reliability. However, the unprecedented rate of announced, but not yet evaluated, baseload generation retirements and uncertainty in future firm capacity additions creates a tension between maintaining reliability and transitioning away from baseload generation.

E. MISO Retirement Studies

The current process for retirement of generation resources in the MISO footprint is generally governed by Attachment Y to the MISO Tariff. Preliminary retirement studies fall under Attachment Y2, which is a confidential MISO analysis to determine if any adverse system impacts would occur as a result of potential generating resource retirement – without/prior to committing to retire or suspend the resource. If adverse impacts are identified, they provide an indication of the mitigations that would need to occur prior to actual unit retirement. As we discuss below, we submitted requests for several Attachment Y2 studies as part of this Baseload Study.

Final determination of adverse impacts however, occurs with an Attachment Y notice – or new provisions under Attachment X of the MISO Tariff, if the notice of retirement includes replacement generation. In May 2019, FERC approved changes to the Attachment X Tariff that allows current generation owners to retain and reuse the interconnection rights when a resource retires, within certain technical and timing limitations on the new generator.[25] The new generating units could be developed on the same site, or on a site in close proximity that uses the same grid interconnection point. The resulting studies under this provision of Attachment X, the generation replacement is considered as part of MISO's analysis of potential adverse impacts. We discuss Attachment X and its importance in achieving the fleet transformation we

[24] *See* "NERC Long Term Reliability Assessment 2018" at 14. Available at: https://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/NERC_LTRA_2018_12202018.pdf

[25] In summary, these changes allow for transfer of interconnection rights from a retiring generation resource to a replacement resource that: (1) Is located at the same point of interconnection as the retiring resource, (2) Is less than or equal to the generating capacity of the retiring resource, (3) Does not result in an adverse impact to the transmission system. *See*: https://www.ferc.gov/CalendarFiles/20190515181059-ER19-1065-000.pdf

envision in Appendix I: Supporting Infrastructure: Transmission & Distribution provide with this Resource Plan.

1. *Preliminary Retirement Studies of NSP System Baseload Units*

Attachment Y2 studies assess current, point-in-time system impacts in the absence of the identified generating resource(s). The study impacts are measured based on the criteria set forth in the MISO Business Practices Manuals, The studies assess transmission system performance to identify any violations of planning criteria due to the unavailability of the generation resource. The relevant MISO Transmission Owner and/or regional reliability criteria are used for monitoring such violations. The Attachment Y2 studies are not intended to determine long-term system reliability impacts, which is why we supplemented them with other reliability studies to provide further insights into impacts from potential retirement scenarios. It is important to note that the assumptions used in the MISO Y2 studies are based on expected conditions at the time they were initiated in 2018, plus the addition of certain pending and proposed generating units, including the Sherco CC and our approved and in-progress wind projects.[26]

For purposes of this Baseload Study, we submitted seven Attachment Y2 study requests with MISO – all of which use a retirement date of May 31, 2027, on models developed to depict 2030 system conditions as follows:

<u>Y2 Baseload Unit(s) Retirement Scenarios</u>
Sherco Unit 3
Allen S. King (King)
Prairie Island (PI)
Monticello (Monti)
All Nuclear (Monti and PI)
All Coal (Sherco 3 and King)
All Coal and All Nuclear

2. *Y2 Study Results*

Generally, the studies found that reconductoring (or line rebuilds) and transformer replacement would be needed to achieve adequate performance for all the scenarios analyzed. In addition, the observed voltage violations would require installation of

[26] MTEP17 (built for the 2017 MISO planning cycle) model series 2027 scenarios that were scaled to represent 2030 load levels. The model also included the following pending and proposed generating units: Crowned Ridge 1 Wind, Crowned Ridge 2 Wind, Crowned Ridge 3 Wind, Blazing Star 1 Wind, Blazing Star 2 Wind, Sherco CC.

extensive reactive devices throughout the region due to the loss of dynamic reactive support from the large amount of retiring resources.

The studies also found that if Xcel Energy were to retire all of its remaining baseload units about the same time, which would be the majority of the large power producing units in the Upper Midwest, it would put a substantial strain on the BES to import power from the rest of MISO. It would also substantially impact MISO's ability to balance out the system to allow for the needed high renewable transfers to other parts of MISO. The Y2 study that examined the combined retirement of the Monticello Unit 1, Prairie Island Units 1 & 2, King Unit 1 and Sherco Unit 3 at the same time stated the following:

> The combined retirement…causes extensive thermal overloads and numerous voltage issues that would require substantial reinforcements to fully address the issues and permit retirement. It is unlikely that the large number of upgrades needed to alleviate thermal overloading and voltage issues would be completed before the planned retirement date resulting in the need for one or more generators to be retained as System Support Resources.

MISO currently is able to use the large Xcel Energy baseload generating units to help balance out the system and provide significant amounts of system response – allowing for high renewable transfers to other parts of MISO. On low wind days, the large generating units are also needed to replace the lost energy from the renewable sources to reliably serve customers' needs. An orderly retirement schedule with sufficient lead times is necessary to ensure reliability mitigations and adequate support of renewables integration and transfers, including generator replacements and transmission development.

Incremental retirements identified more manageable impacts. In the case of a King-only or Sherco 3-only retirement, neither resulted in thermal or voltage degradation such that the Unit would be designated as a SSR.[27] However, the All Coal/King and Sherco 3 combined study found the need for an estimated $38.2 million to address several thermal overloads. The Monticello Y2 study showed some thermal overloads that could be addressed with system readjustment. Some voltage issues would additionally need to be addressed before it could retire. The retirement of Prairie Island would require some voltage mitigation, but there were no thermal overload

[27] In some cases, a generator may be designated as a System Support Resource (SSR), which is determined by the presence of unresolved violations of reliability criteria that can only be alleviated by the SSR generator and where no other mitigation is available. Evaluation of mitigation solutions will consider the use of operating procedures and practices such as equipment switching and post-contingent Load Shedding plans allowed in the operating horizon.

issues. Retirement of all nuclear units would result in some thermal and voltage issues that would need mitigation before they could be retired.

As noted above, the All-Coal and All-Nuclear Retirement scenario resulted in major thermal and voltage violations. This scenario would require significant system upgrades to eliminate all of the thermal and voltage issues; the MISO planning level estimates for all transmission facilities improvements to address the steady state thermal and voltage issues was estimated to be $299.3 million. As transmission development, permitting and construction processes generally involve rather long timeframes of 5-7 years on the low end and as much as 15-20 years in some cases, we expect that addressing all of the system violations would involve an extensive effort over a relatively long timeframe to be complete.

That said, the MISO system is dynamic and expected conditions will change when new generation comes online, existing generation retires, new transmission lines are constructed, or existing lines are reconfigured. These results are indicative of issues requiring mitigation at the time of these studies. A more comprehensive analysis will be necessary in conjunction with a notice under Attachment Y or Attachment X in closer proximity to the planned retirements to determine final adverse impacts and to develop mitigation options.

The Y2 Studies identified planning level costs, which are estimates provided only as an indication of the upgrades needed to mitigate issues caused by the retirement(s) and are based on assumptions that include new proposed generation resources without any of the associated network upgrades.[28] The Y2 reports clarify that further analysis is required in a subsequent retirement study to fully consider only those interconnected resources with executed interconnection agreements in order to more accurately determine costs of the mitigation upgrades.

For purposes of this Baseload Study, we incorporated the MISO planning level estimated costs from the Y2 studies into our economic modeling of the baseload retirement scenarios. We outline our Strategist analysis in Part G below, and discuss it in more detail in Chapter 4: Preferred Plan, Chapter 5: Economic Modeling Framework, and Appendix F2: Strategist Modeling Assumptions & Inputs.

[28] Costs specified in the Attachment Y2 studies are based on the "MISO Transmission and Substation Cost Estimation Guide for MTEP" except where costs were established for previously identified upgrades and are subject to change.

F. Xcel Energy Transmission Reliability Studies

As discussed above, the MISO Y2 study process focuses on maintaining transmission system elements within their thermal and voltage limits.[29] While this provides a thorough analysis of the impacts of the retiring generation resource in those two areas, it does not adequately capture the impacts that resource(s) has on the stability of the power system, which requires a more focused area of study around the retiring resource.

Historically, limiting the study to voltage and thermal assessments was sufficient. This was because individual generating unit changes had limited impact on overall system reliability because there were excess capabilities from the remaining generation fleet to replace/adequately perform the necessary stability services. However, as the system moves further away from large synchronous generating facilities, system stability and response becomes a significantly greater risk for generation retirement than voltage violations or thermal constraints. Therefore, a more robust study that includes consideration of other grid impacts is necessary to ensure system reliability and resilience. The complementary studies we undertook studied other grid impacts of various generation retirement scenarios using a more traditional NERC reliability assessment approach.

Combined with the Y2 results, these studies provide a more robust analysis of the potential retirement of our remaining baseload units. The results from our analysis indicate the following:

- There will be several thermal and voltage violations that will need to be addressed to remain NERC compliant.
- The location of resources plays a large part in the ability of the system to respond to faults. In the absence of large synchronous resources replacing retiring units in place, significant transmission infrastructure development will be necessary. See Figures 2 and 3 (Stability Plots) below.
- While a zero baseload future may be able meet certain aspects of a reliable power system, current technologies cannot maintain system stability, adequately recover from contingencies, nor can they ensure reliable service to customers every hour of every day without the assistance of a sufficient level of synchronous generation.

Final system impacts will depend on the scenario, the specific Unit retirement(s), and

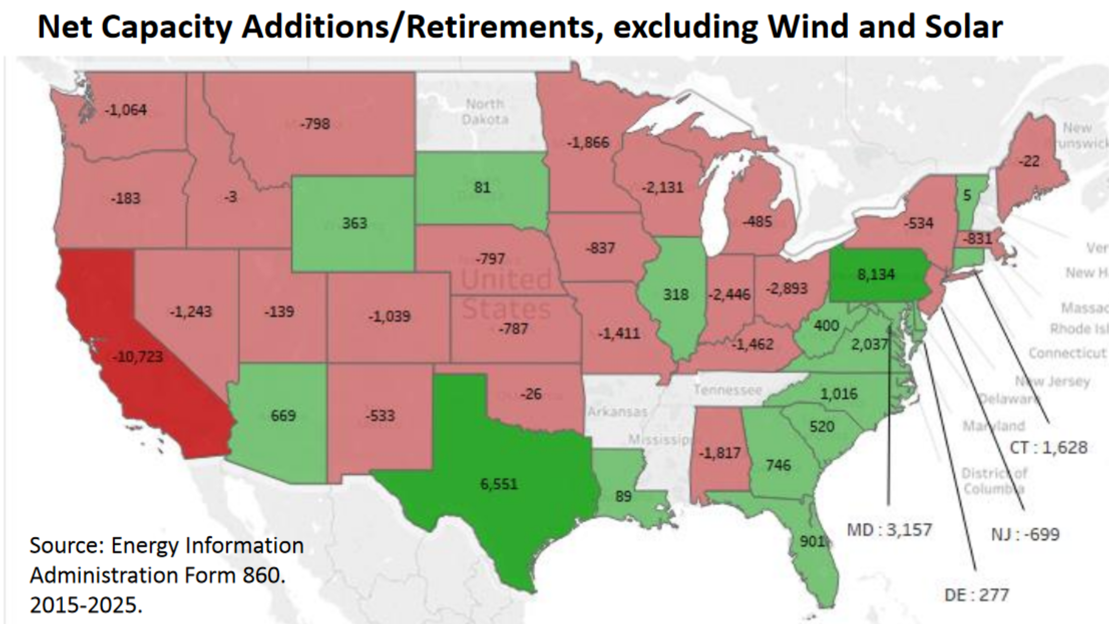
[29] MISO will perform limited stability analysis upon request.

what, if anything, will replace the Unit(s).

1. Approach

We undertook these studies at a point in time in the industry when there are more large generating units retiring than being added to the grid. As shown below, the capacity availability in the MISO states is projected to fall by nearly 8,700 MW by 2025 from 2015 totals.

Figure 1: Net Capacity Additions, Excluding Wind and Solar



With the trend of declining levels of large synchronous generating units being largely replaced with renewable and intermittent resources in mind, we undertook two study efforts to determine the impact of baseload retirements on the Upper Midwest grid:

- **Metro Stability Study** – analyzed the capability of the Twin Cities metro area to remain stable utilizing a scenario in which large scale baseload retirements took place both on the NSP System, as well as neighboring systems.
- **NSP Resource Contribution to System Stability** – analyzed the stability of the Upper Midwest grid when only the NSP System reduced its baseload generating resources.

These technical studies simulate a number of varied conditions that consider changes in customer loads, projected changes to the generation mix, and ways to use the transmission system most efficiently. The studies generally analyze the way power flows over the grid, and search for places where the system might fail to maintain a stable power signal, assuming specific circumstances. Study 1 focused on regional (neighboring utilities') changes to determine local (Twin Cities Metro) impacts. Study 2 was to determine the regional impact of NSP System changes.

2. *Study 1: Metro Stability Study*

The goal of this study was to determine the minimum amount of system services required to maintain a stable major demand center, which in this case was the Twin Cities Metro area, with major changes to the surrounding system. The results indicate that while a zero baseload future may be able meet certain requirements for a reliable power system, the current technologies on the system today cannot maintain system stability without the assistance of a sufficient level of synchronous generation.

a. Study Assumptions and Approach

For the purposes of this Study, we utilized three natural gas generators located at strong points on the system to determine the *minimum amount* of system services necessary to maintain a stable major demand center with major changes to the surrounding system.[30] We performed the stability assessment using the 2018 MTEP dynamic model, representing light load with 90 percent wind output conditions in the year 2023. We assumed no load growth between 2023 and 2030 to limit the number of variables potentially affecting the results.

Consistent with the industry trends and our clean energy vision, we expect substantial additions of renewable energy to be added to the system as we transition the our generating fleet. For purposes of this Study, we assumed the addition of 5,800 MW of nameplate renewable generation dispatched at 4,440 MW to depict a higher reliance on renewable energy resources – and which would replace the assumed retirements. We show the renewable additions in Table 2 below.

[30] This does not take into account maintenance, forced outages, or economic factors into the ability of those services to be provided in all hours by the three units utilized in the analysis, which can increase the total number of units required to provide sufficient levels of service in all hours.

Table 2: Stability Study – Renewable Generation Additions Modeled

Location	State	Fuel	kV	Number of Megawatts: Nameplate	Number of Megawatts: Dispatched (Pgen)
Alexandria	MN	Solar	345	100	60
Quarry	MN	Solar	345	100	60
Chub Lake	MN	Solar	345	100	60
Prairie Island	MN	Solar	345	200	120
North Rochester	MN	Solar	345	150	90
Byron	MN	Solar	345	150	90
Pleasant Valley	MN	Solar	345	150	90
Sheas lake	MN	Solar	345	100	60
Wilmarth	MN	Solar	345	100	60
Adams	MN	Solar	345	100	60
Cedar Mountain	MN	Solar	345	150	90
Big Stone	MN	Solar	345	150	90
Hazel Creek	MN	Solar	345	150	90
Lyon County	MN	Solar	345	150	90
Nobles	MN	Solar	345	150	90
Split Rock	MN	Solar	345	150	90
Owatonna	MN	Solar	161	100	60
Fort Ridgley	MN	Solar	115	100	60
Chanarambie	MN	Solar	115	100	60
Brookings	SD	Solar	345	150	90
Lyon County	MN	Wind	345	350	315
Hazel Creek	MN	Wind	345	250	225
Nobles	MN	Wind	345	250	225
Split Rock	MN	Wind	345	250	225
Lakefield	MN	Wind	345	200	180
Cedar Mountain	MN	Wind	345	250	225
Pleasant Valley	MN	Wind	345	250	225
Mchenry	ND	Wind	230	200	180
Ellendale	ND	Wind	345	200	180
Bison	ND	Wind	345	300	270
Big Stone	SD	Wind	345	400	360
Brookings	SD	Wind	345	300	270
Total				5,800	4,440

Table 3 below shows the resource retirements we applied in this analysis, which are intended to reflect a regional trend of baseload unit retirements in the Upper Midwest. These are not intended to represent actual Unit retirement plans; these are only assumptions utilized to develop a model representing the intended scenario.

Table 3: Generation Turned Off In Analysis

Bus Name	Pgen (MW) in MTEP Model	New Pgen (MW)
[PR IS31G 20.000]	553	0
[PR IS32G 20.000]	552	0
[MNTCE31G 22.000]	592.9	0
[FEP CT G 18.000]	63.4	0
[FEP ST G 13.800]	50	0
[ARNOLD1G 22.000]	651	0
[OTTUMW1G 24.000]	457.3	0
[COL G1 22.000]	585	0
[COL G2 22.000]	585	0
[WES G4 19.000]	600	0

b. Study Methodology and Results

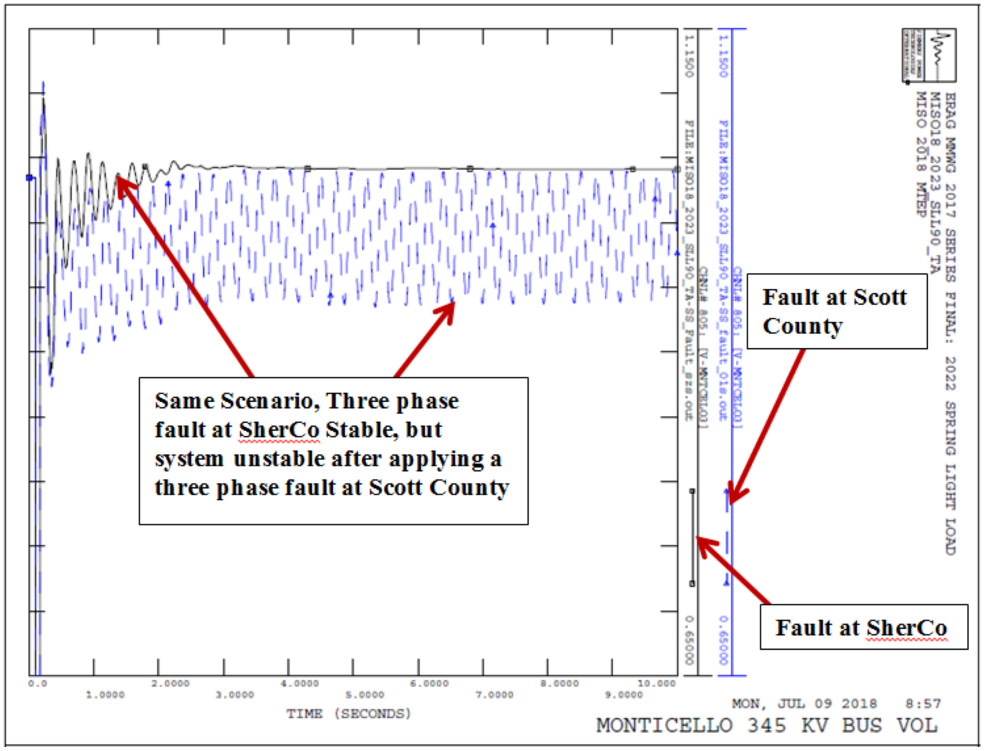
We then introduced faults on the system to assess the ability of the grid to recover and return to a normal state. We outline the fault events that we analyzed in Table 4.

Table 4: Major Faults Analyzed

Fault Name	Fault Description	Result
Fault_01s	Normal close in 3 phase fault on Scott County - Helena 345 kV line near Scott County	Unstable
Fault_02s	Normal close in 3 phase fault on Scott County - Helena 345 kV line near Helena	Unstable
Fault_03s	Loss both Cedar Mountain – Helena circuit with normal clearing	Unstable
Fault_szs	Normal close in 3 phase fault on SherCo - Coon Creek 345 kV line near SherCo	Stable

Figure 2 illustrates the importance of location and siting on system stability. This scenario is demonstrating the effect of a single fault on the system. The black line represents a fault near our Sherco facility, which in this scenario has our future Sherco CC online; the system recovers rather quickly. The blue line represents a similar fault at Scott County, where there is no nearby generating resource – and the system becomes unstable.

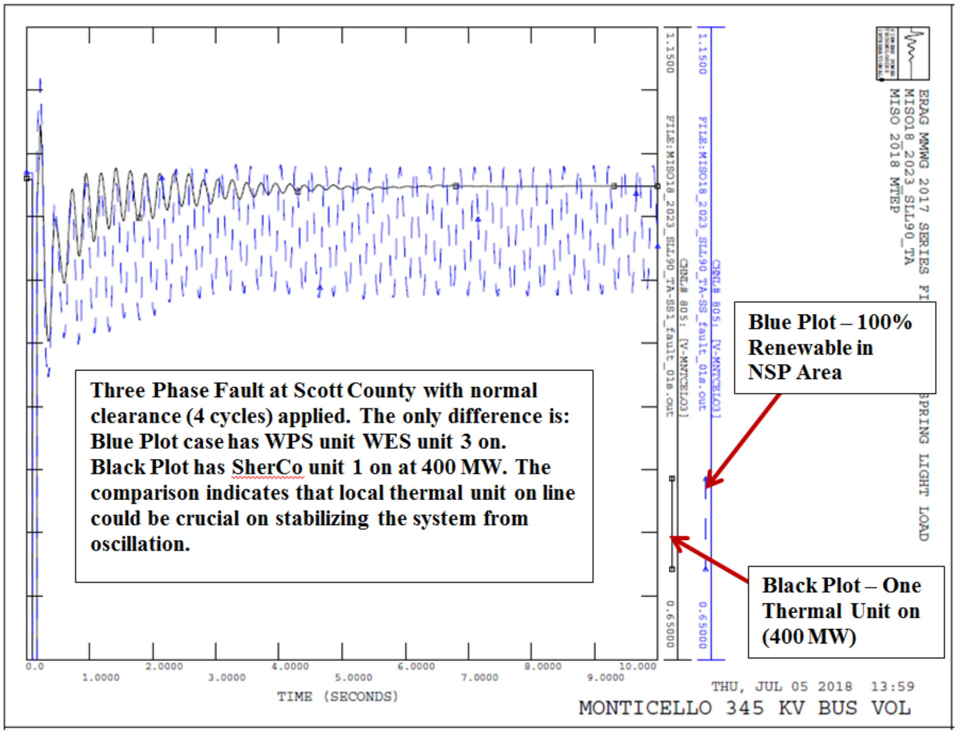
Figure 2: Stability Plot – Importance of Resource Siting on Stability



The results of this scenario demonstrate that the system remains stable when a fault occurs on a part of the transmission system where sufficient system stability services – in this case, a large synchronous generator – are available nearby. Whereas, experiencing a fault at a location with distant synchronous resources connected through long transmission lines to demand centers greatly increases the risk of system instability.

Similar to how system stability differs based on the location of the fault in relation to a system stability resource, the location of synchronous resources plays a large part in the ability of the system to respond to faults. As shown in the stability plot in Figure 3 below, the system response to a fault at Scott County is unstable when relying on energy imports from non-NSP System resources. When we moved a same-sized resource to a location nearer to the Twin Cities Metro area, the system regains stability with little issue after experiencing the same fault.

Figure 3: Stability Plot – Importance of Resource Siting on System Response



As the transition to increased reliance on renewable resources continues, replacement of synchronous resources at current resource locations or substantial transmission infrastructure development will be fundamentally essential to the reliable delivery of energy.

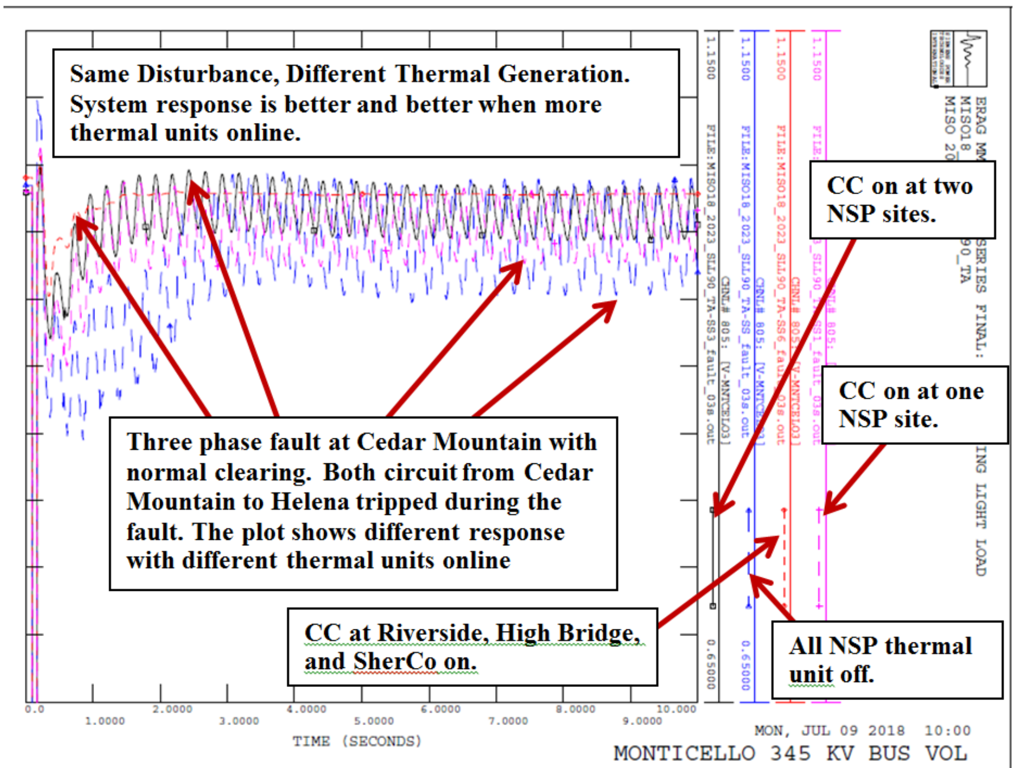
c. Step-by-Step Re-Aaddition of Gas Units in Metro to Regain System Stability

Moving away from the specific locational aspects of faults and resources, we analyzed a wider range of events of differing severities to determine what is needed to maintain system stability with high reliance on renewable resources.

To determine the level of stability services needed, we stepped through turning generating units retired in earlier scenarios back on to analyze the impacts under severe conditions. In this scenario, we turned-off all of the Upper Midwest synchronous generating units, and a major transmission path for renewable generation to get to the Metro area.

As shown in the results of this analysis below, while a zero baseload future may be able meet certain requirements for a reliable power system, the current technologies on the grid today cannot maintain system stability without the assistance of a sufficient level of synchronous generation. An equivalent level of system services as provided in the model by Riverside, High Bridge, and the Sherco CC are all required to be operating at all times to ensure the system remains stable and can sufficiently recover from contingencies on the transmission system.

Figure 4: Incremental Steps to Result in 3-Unit Metro Equivalent Services



Every generation resource on the system can have significant impacts on the stability of the system, which may differ based on the order in which they are retired or replaced. This study demonstrates that it is vital to perform a system stability analysis, and resolve any issues, for each potential unit retirement proximate to the planned retirement, so the analysis as closely as possible mirrors expected actual conditions at the time of unit retirement.

3.   Study 2: NSP Resource Contribution to System Stability

The second study also analyzed the stability of the grid in the Upper Midwest – however when only the NSP System reduced its baseload generating resources. In this analysis, we analyzed the effects of local/NSP System baseload reductions on a regional basis. Our objective with this Study was to determine the importance of retaining sufficient system services in high demand areas (such as the Twin Cities Metro area) in order to understand the role that current NSP System baseload generating resources have on the stability of the Upper Midwest BES and the ability of non-metro locations to remain stable in low Metro-area baseload scenarios.

The results of this analysis found that the reduction in synchronous generation resources on the NSP System can have wide-ranging impacts on system stability and reliability. In particular, the retirement of NSP System baseload units without similar replacements at or near their current locations results in insufficient margin on the system during summer peak scenarios and system instability in light load scenarios.

a. Study Assumptions and Scenarios

We analyzed light load, summer shoulder, and summer peak scenarios for the year 2023 in this study. Renewables in the NSP System are modeled at an 80 percent level in all three models, while the existing natural gas CCs are turned-on to represent 20 percent firm dispatchable generation in each model. We outline the dispatch assumptions we made in the three different load scenarios in Table 5 below.

Table 5: Dispatch Assumptions

Year	Season	Load Level	20% Thermal
2023	Light Load	5,150 MW	1,030 MW
2023	Summer Shoulder	7,195 MW	1,440 MW
2023	Summer Peak	10,250 MW	2,050 MW

As with Study 1, we applied baseload unit retirements in this analysis that are not intended to represent actual retirement plans. Rather, the assumptions in Table 6 below were only used to develop a model representing the intended scenario.

Table 6: Generation Turned-Off in Analysis

Baseload Generator	Year 2023 Summer Light Load	Summer Shoulder	Summer Peak
Sherco #1	Offline	478.3 MW	730 MW
Sherco #2	Offline	427.2 MW	730 MW
Sherco #3	Offline	608 MW	925 MW
King	Offline	560 MW	560 MW
Monticello	593 MW	637 MW	637 MW
Prairie Island 1	553 MW	553 MW	553 MW
Prairie Island 2	552 MW	552 MW	552 MW

Table 7 below outlines the resources we used to replace energy supply in the absence of the assumed retirements above.

Table 7: Additional Generation Assumptions

Bus Number	Bus Name	Unit	2023 Summer Light Load	Summer Shoulder	Summer Peak
600007	RIVRS77G 16.000	7	160 MW	160 MW	Online
600070	RIVRSIDEG9 718.000	9	158 MW	158 MW	Online
600071	RIVRSIDG10 718.000	10	158 MW	158 MW	Online
600065	HBR C71G 18.000	7	162 MW	162 MW	Online
600066	HBR C72G 18.000	8	162 MW	162 MW	Online
600067	HBR S73G 13.800	9	226 MW	226 MW	Online
600012	BLK D72G 13.800	2	N/A	115 MW	Online
600164	J399 BLK D7618.000	6	N/A	214 MW	Online
600047	G261 MEC-CT115.000	1	N/A	N/A	Online
600172	G261 MEC CT215.000	1	N/A	N/A	Online
600046	G261 MEC-ST 19.500	1	N/A	N/A	Online

In this Study, we compare the transmission line outages to a Base scenario that has no outages, as follows:

- Base: No Outages
- Outage #1 (PO1): Sheas Lake – Helena 345 kV line
- Outage #2 (PO2): Scott County – Helena 345 kV line
- Outage #3 (PO3): Chub Lake – Helena 345 kV line

Finally, Table 8 below outlines the various faults that we analyzed for each of the above Outage Scenarios.

Table 8: Faults Analyzed

Name	Description
Fault_PI	5 Cycle 3 PH fault at PI
Chisago-345	5 Cycle Three phase fault at Chisago
Fault_eks	5 Cycle Three phase fault at King
Fault_odell	5 Cycle Three phase fault at CRANDAL
Fault_01s	5 Cycle Three phase fault at SherCo
Fault_05s	5 Cycle Three phase fault at Helena on Helena - Sheas Lake line
Fault_04s	4 Cycle Three phase fault at Chisago 500 kV
Monti-slf2	SLGF at Monticello
Monti-3ph2	5 Cycle Three phase fault at Monticello
Fault_pys	SLGF at PI
fault_02s	5 Cycle Three phase fault at Helena on Helena - Scott County line
Fault_03s	5 Cycle Three phase fault at Helena with common structure out
Fault_mcs	SLGBF fault at Sherco on Coon Creek #3 line with 8M40 Stuck
Fault_mts	SLGBF fault at Monticello with 8N6 stuck
Fault_pcs	SLG fault at King-Eau Claire line with a breaker failure at king
Fault_n03s	12 Cycle SLG fault at Red Rock 345 kv bus with failure of 8P24
Fault_mw3s	3 phase fault at Wilmarth on Wilmarth - Sheas Lake 345 kV line
Fault_mqs	SLGBF fault at Sherco on Unit #3
Fault_mjs	SLGBF fault at CHISAGO
Fault_m6s	5 Cycle 3 PH fault at Parkers Lake 345 kV
Fault_m5s	10 Cycle 3 PH fault at Coon Creek 345 kV bus with failure of 8M40
Fault_m4s	10 Cycle 3 PH fault at Terminal
3P_Terminal_TR9_B3s	3 phase fault at Terminal 345 kV bus, normal clearing
3P_Adams_Mitch	Three phase fault at Adams
3P_Briggs_NorthMad	Three phase fault at Briggs Road
3P_Brookings_Hawks	Three phase fault at Brookings County
3P_ChubFault_OpentoHelena	Three phase fault at Chub lake on Chub Lake - Helena line
3P_HelenaFault_OpentoChub	Three phase fault at Helena on Chub Lake - Helena line
3P_Lakefield_Huntly	Three phase fault on Lakefield JCt - Huntley line
3P_Lakefield_LakeJct	Three phase fault on Lakefield JCt - Lakefield line
3P_Lakefield_Obrien	Three phase fault on Lakefield JCt - Obrien line
3P_Sioux_SplitRock	Three phase fault on Sioux - Split Rock line
3P_Split_Nobles	Three phase fault on Split Rock - Nobles County line
SLG_Alexandria_BKR3325	SLG fault at Alexandria with breaker 3325 stuck
SLG_Hawksnest_8N82_Stuck	SLG fault at Hawksnest with breaker 8N82 stuck
SLG_Lakefield	SLG fault at Lakefield with breaker stuck
SLG_Wilmarth_8S23_Stuck	SLG fault at Wilmarth with breaker 8S23 stuck

b. Study 2 Results

In general, the lack of system margin from the significant absence of synchronous generation results in the inability of the system to recover from system events.

This lack of margin is also evident when analyzing the loss of a major transmission source to the Twin Cities Metro area. If enough of these sources are unavailable, the system can become unstable, even with non-NSP System baseload generation resources available as they are today. In addition to the reliability and stability implications of insufficient resource availability in the correct locations, heavy reliance on renewable resources located only in the highest capacity factor/highest concentration locations, such as southwestern Minnesota, results in a less resilient system. In these scenarios, utilizing the current transmission system creates a single point of failure that can result in an inability to operate the system. This further demonstrates that it is likely that significant transmission development will be necessary as current baseload generating resources retire and renewable resources take an increasingly large role on the Upper Midwest grid.

Table 9 below shows the results for the scenarios (Base, PO1, PO2, PO3) for each of the outage events – with the yellow highlights being thermal overloads. We note that in Summer Peak conditions for PO1 and PO2, the model could not converge toa solution, meaning significant upgrades would be required if only to create a stable enough system and enable the analysis of other system impacts.

Table 9: Thermal Overload Results

Facility	2023 SLL				2023 SH90				2023 SUM			
	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3
Helena – Scott County 345 kV	1078 MW	678 MW	N/A	1602 MW 118%*	1545.2 MW 118%*	1158.5 MW	N/A	2232.5 MW 173%	1737.3 MW 138%	No Solution	No Solution	2323 MW 188%
Helena – Chub Lake 345 kV	720 MW	394 MW	1391 MW	N/A	1001 MW	695.2 MW	1931 MW 117%	N/A	868.5 MW			N/A
Sheas Lake – Helena 345 kV	1040 MW	N/A	809 MW	905.4 MW	1125.3 MW	N/A	780.4 MW	930 MW	1721.8 MW 137%			1544.5 MW 125%

*The line rating is calculated based on the bus voltage

Similar to the thermal overloads above, Table 10 outlines the voltage violations in the same grid conditions, scenarios, and outage conditions. In this case, the violations occur only in summer peak conditions. However, again, there are two cases where the model was unable to solve the violation.

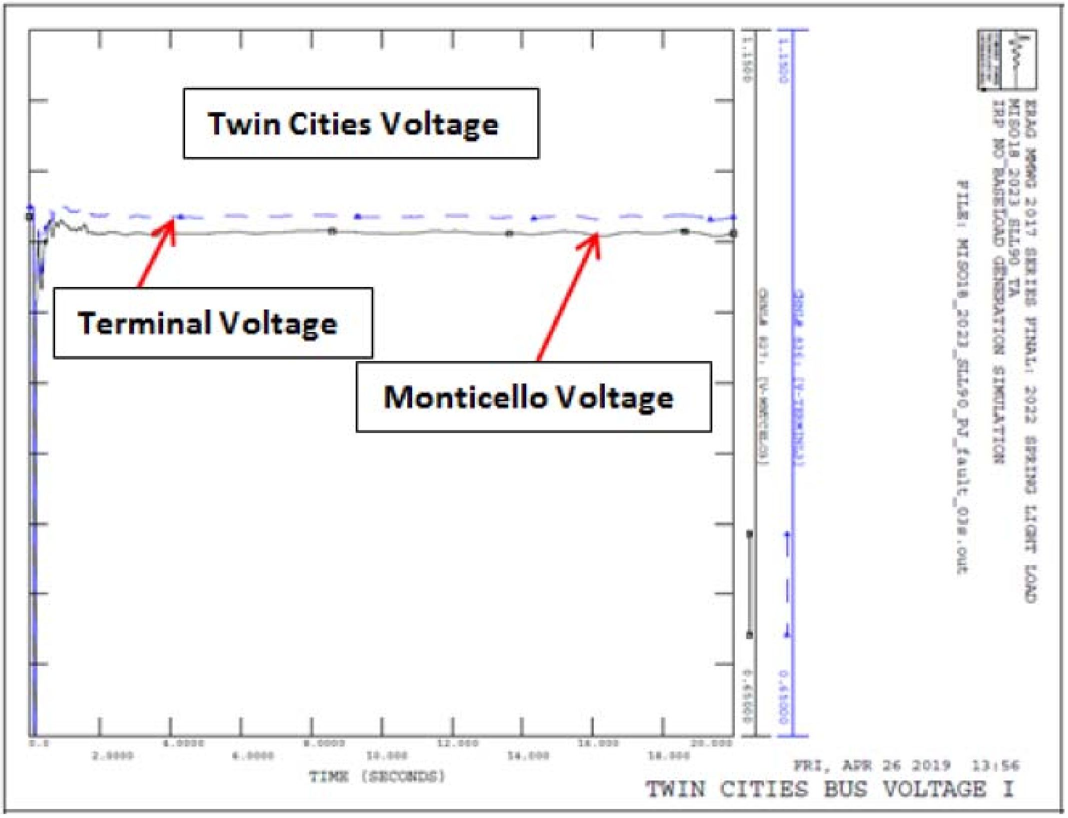
Table 10: Voltage Violation Results

Facility	2023 SLL				2023 SH90				2023 SUM			
	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3	Base	PO1	PO2	PO3
Helena 345 kV	1.006	1.011	0.987	0.990	0.954	0.954	0.920	0.938	0.921	No Solution	No Solution	0.896
Sheas Lake 345 kV	1.001	1.006	0.986	0.988	0.951	0.978	0.924	0.938	0.917			0.898
Scott County 345 kV	1.015	1.017	1.016	0.999	0.968	0.972	0.975	0.948	0.940			0.910

As a result of increased reliance on renewable resources sited in locations to take advantage of higher capacity factors, the transmission system between those high capacity factor/concentration areas and areas of high energy usage become overly stressed, resulting in violations of facility ratings. As is the case in the summer peak scenarios, insufficient margin is available to come to a solution during higher demand scenarios.

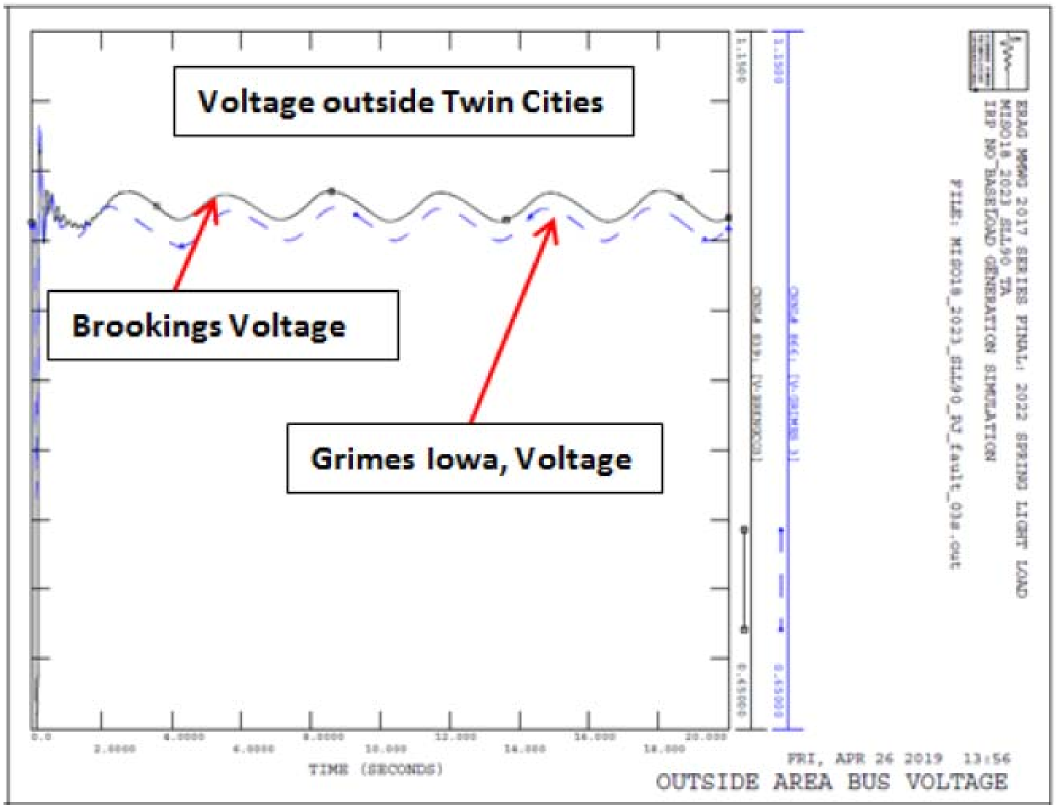
The stability plots in Figures 5 and 6 below show this effect. While the Twin Cities Metro area is able to mostly recover from an event, in all system disturbances tested, the ability of the system in southwest Minnesota and Iowa where there are large concentrations of renewables experience difficulty recovering voltage stability in light load cases.

Figure 5: Stability Plot – Insufficient System Damping
Twin Cities Metro Area Voltage



Damping is the flattening of the line as time progresses. Figure 5 above and Figure 6 below show that, while the Twin Cities Metro area can maintain stability, other areas outside of the Twin Cities Metro are unable to do so.

Figure 6: Stability Plot – Insufficient System Damping
Outside Twin Cities Metro Area Voltage



While the scenarios developed for the light load cases were able to fully solve, despite some inability to remain stable, the summer scenarios with high levels of energy demand that are shown as "no solution" in yellow highlight in Tables 9 and 10 above resulted in system collapse due to insufficient resource margin available on the system to rebalance and regain stability after an event is experienced..

Figures 7 and 8 below demonstrate the system collapse, which is would result in widespread power outages and require black start procedures for MISO Load Resource Zone 1 to rejoin the grid once the system regained stability.

Figure 7: System Collapse – Summer 2023 P01 Case

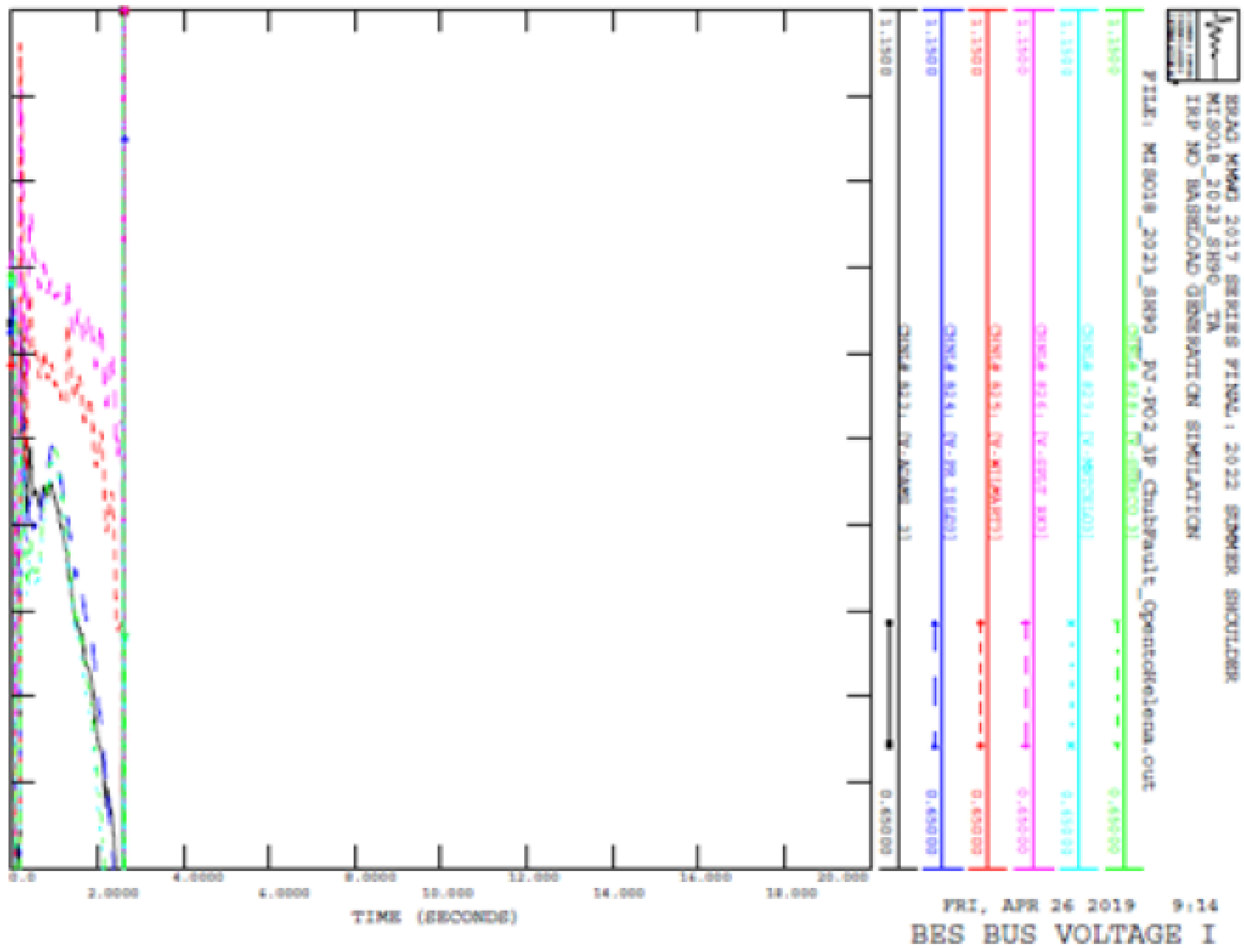
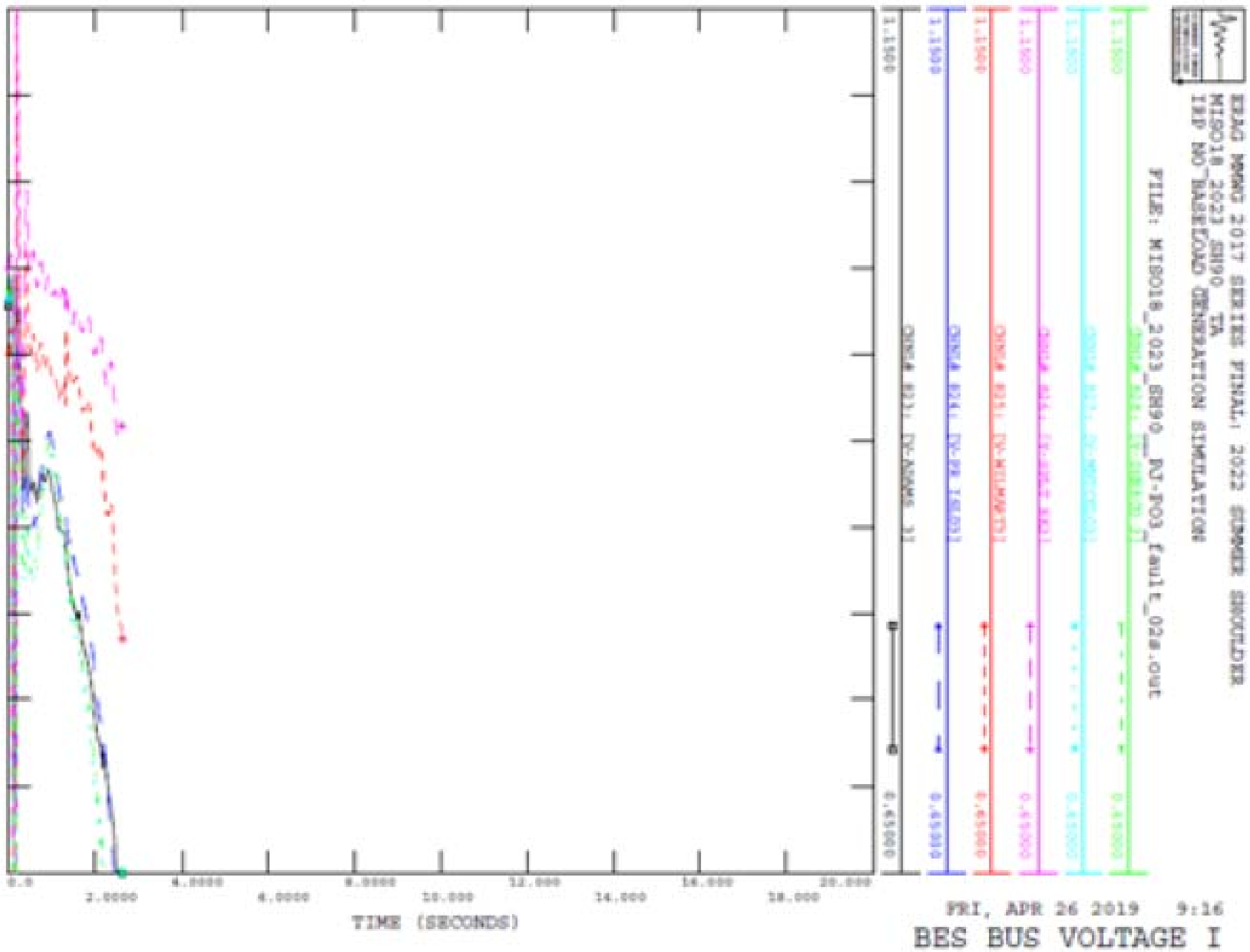


Figure 8: System Collapse – Summer 2023 P02 Case



4. *Summary of Results*

As shown by the results of this analysis, the reduction in synchronous generation resources on the NSP System can have wide-ranging impacts on system stability and reliability. In particular, the retirement of NSP System baseload units without similar replacements at or near their current locations results in insufficient margin on the system during summer peak scenarios, and system instability in light load scenarios.

The lack of system margin results in the inability of the system to recovery from any of the system events analyzed in either the base summer peak scenario or the prior outage summer peak scenario. This lack of margin is also evident when analyzing the loss of a major source to the Twin Cities metro area. If enough of these sources are unavailable, the system can become unstable, even with non-NSP System base load generation resources available as they are today.

In addition to the reliability and stability implications of insufficient resource availability in the correct locations, heavy reliance on renewable resources located only in the highest capacity factor locations results in a less resilient system. In these scenarios, utilizing the current transmission system results in a single point of failure that can result in an inability to operate the system. Additional transmission development will likely be necessary to improve system resilience and facilitate increased levels of renewable resources in the Upper Midwest.

These two efforts help to better understand the impacts of increased baseload retirement on system stability and reliability trend toward the same conclusion. Without sufficient dispatchable and synchronous generation resources available to maintain sufficient margin, the system cannot remain stable resulting in even minor disturbances leading to the potential for cascading failures and system collapse. In addition, increased reliance on renewable resources without utilizing current interconnection rights and transmission system capabilities will result in significant transmission expansion required to maintain system reliability and ensure the safe, resilient and cost effective delivery of power.

G. Strategist Baseload Economic Analysis

To help inform our Preferred Plan with an economic view of an orderly, cost—effective baseload retirement schedule, we developed fifteen Strategist scenarios with varying combinations and timing of baseload unit retirements. These scenarios also identified the size, type, and timing of new resources needed to continue meeting customers' needs and achieve our 2030 carbon reduction goals.

We compared these scenarios to a Reference Scenario, which is essentially an extension of our most recent Resource Plan with respect to all of the baseload units retiring at their currently scheduled retirement dates.[31] These scenarios are generally grouped into "families," which we outline below. First, however, we summarize the retirement dates for the respective baseload units in the Table 11.

[31] The Scenarios and Sensitivities are discussed in Chapter 5: Economic Modeling Framework and Appendix F2: Strategist Modeling Assumptions & Inputs.

Table 11: Economic Analysis – Baseload Unit Retirement Date Assumptions

Baseload Unit	Current Schedule/ Reference Case	Early Retirement	Life/License Extension
A.S. King	2037	2028	NA
Sherco Unit 3	2040	2030	NA
Monticello	2030	2026	2040
Prairie Island Unit 1	2033	2024	2043
Prairie Island Unit 2	2034	2025	2044

Early Coal Family. These scenarios are designed to evaluate the economics of retiring King and/or Sherco 3 early.

- Scenario 2 *(Early King)* – King is retired early; Sherco 3 and the nuclear units are unchanged.
- Scenario 3 *(Early Sherco 3)* – Sherco 3 is retired early; King and the nuclear units are unchanged.
- Scenario 4 *(Early All Coal)* - King and Sherco 3 are retired early; the nuclear units are unchanged.

Early Nuclear Family. This family of scenarios is designed to test the economics of retiring Monticello and/or Prairie Island early, either alone or together – and with the combination of early coal retirements.

- Scenario 5 *(Early Monticello)* – Monticello is retired at the end of 2026; coal and Prairie Island are unchanged.
- Scenario 6 *(Early Prairie Island)* – Prairie Island is retired by the end of 2025; coal units and Monticello are unchanged.
- Scenario 7 *(Early All Nuclear)* – Prairie Island and Monticello are both retired early; coal units are unchanged.
- Scenario 8 *(Early All Baseload)* – All baseload units (coal and nuclear) are retired early.

Extend Nuclear Family. This family of scenario is designed to test the economics of re-licensing Monticello and/or Prairie Island and extending the operational life by ten years beyond the current end of license dates.

- Scenario 9 *(Early Coal, Extend Monticello)* – All coal is retired at the early dates; Monticello is extended for 10 years; Prairie Island is unchanged.

- Scenario 10 *(Early King, Extend Monticello)* – King is retired early; Monticello is extended for 10 years; Sherco 3 and Prairie Island are unchanged.
- Scenario 11 *(Early Coal, Extend Prairie Island)* – All coal is retired early; Prairie Island is extended for 10 years; Monticello is unchanged.
- Scenario 12 *(Early Coal, Extend All Nuclear)* – All coal is retired early; Monticello and Prairie Island are extended.
- Scenario 13 *(Extend Monticello)* –Monticello is extended; King, Sherco 3, and Prairie Island are unchanged.
- Scenario 14 *(Extend Prairie Island)* – Prairie Island is extended; King, Sherco 3, and Monticello are unchanged.
- Scenario 15 *(Extend All Nuclear)* – Both Monticello and Prairie Island are extended; King and Sherco 3 are unchanged.

After identifying the scenarios for analysis, we utilized the Strategist modeling tool to identify sets of resources needed to continue to meet customer needs for each scenario, along with their resultant costs and emissions impacts. We also included the planning level mitigation cost estimates from the MISO Y2 studies – and we applied the Reliability Requirement, discussed in detail in Appendix J2.

From a modeling perspective, the Present Value Revenue Requirement (PVRR) and Present Value Societal Cost (PVSC) results are primary indicators of the economics of various scenarios, or paths forward. The modeling indicated that the nuclear extension scenarios paired with early coal retirements yielded the most attractive present value compared to the Reference Case. This economic view of various options provided helpful insights that informed the Preferred Plan we propose in this Resource Plan, which correlates to Scenario 9.

In summary, the baseload retirement aspects of our Preferred Plan include:

(1) Retirement of our remaining two coal units early: King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early).

(2) Operating our Monticello unit through 2040 (10 years longer than its current license) and operate both Prairie Island units through the end of their current licenses (PI Unit 1 to 2033 and PI Unit 2 to 2034).

We discuss results of our Strategist modeling in more detail in Chapter 4: Preferred Plan and Appendix F2: Strategist Modeling Assumptions & Inputs of this Resource Plan.

V. CONCLUSION

We believe the increasing trend toward a clean energy future, along with rapidly advancing technologies and aging generation assets will significantly change the generation mix in Minnesota and across the United States over the next 15-plus years. We have done a comprehensive analysis of the impacts of cost-effective and orderly retirement of our baseload fleet in compliance with the Commission's Order – and in support of our clean energy vision. The results of this Baseload Study informed the Preferred Plan we propose in this Resource Plan, which includes the following baseload actions: (1) Retire our remaining two coal units early – King in 2028 (nine years early) and Sherco 3 in 2030 (ten years early), and (2) Extend the operation of Monticello nuclear 10 years through a license extension, to 2040.

Through this work we believe the retirement of our current baseload units must be orderly, and will be impacted by decisions other MISO generation owners make regarding their baseload units. It will be important to maintain sufficient firm dispatchable, load supporting resources to support integration of renewable resources, and ensure customer reliability and system resilience. Changes in the MISO planning construct are necessary to properly recognize the inherent variable and intermittent nature of renewable resources in meeting customer needs every hour of every day. Finally, we also believe significant new regional transmission development will be necessary to support increased levels of renewable resources and to support the retirement of baseload units.

APPENDIX J2 – RELIABILITY REQUIREMENT

As the Company increases the amount of renewable generation on our system, it is important to recognize that these resources cannot alone reliably provide customers the energy they demand every hour of every day, or maintain the stability of the grid. Until such time as new technologies develop to fully transition the grid to carbon-free resources, some level of load-supporting, firm dispatchable resources is necessary for grid resilience and customer reliability.

As penetration of variable and intermittent resources like wind and solar increase on the grid, it requires a new planning paradigm. The traditional method of planning on a capacity-basis for a single system peak will no longer ensure we meet our customers' needs in every hour. Our planning needs to become energy-oriented and be able to match available generation and customer load as available resources and customer load go up and down every day. A winter peak, while much lower than summer, can be just as challenging to meet if we do not have sufficient resources at the time of the peak. The January 2019 polar vortex is an example of this – but severe winter weather is not the only time this issue can occur. As we discuss below, it can also occur on an otherwise normal winter or summer day.

This planning concern is not limited to the NSP System, but rather across all of MISO's footprint – and in other regions with increasing levels of renewables. Although MISO recognizes these challenges, its current planning constructs do not fully incorporate measures to address them. We have therefore developed a Reliability Requirement to inform this Resource Plan and mitigate risks to customer reliability and system resilience as MISO determines how to incorporate these issues into its planning process. The Reliability Requirement will ensure we have a sufficient level of dispatchable load supporting resources that can quickly respond to fill gaps between customer demand and energy supply at times of low or non-existent renewable generation. In short, it ensures that we can serve customers with reliable energy every hour of every day.

Below, we discuss the specific system conditions and events we believe call for the addition of the Reliability Requirement. We also discuss how we derived this requirement, and how we applied it in the modeling underlying this Resource Plan. Because the Reliability Requirement involves consideration of the level of market reliance we can reasonably depend on, we start with an overview of MISO and its resource zones.

I. MIDCONTINENT INDEPENDENT SYSTEM OPERATOR OVERVIEW

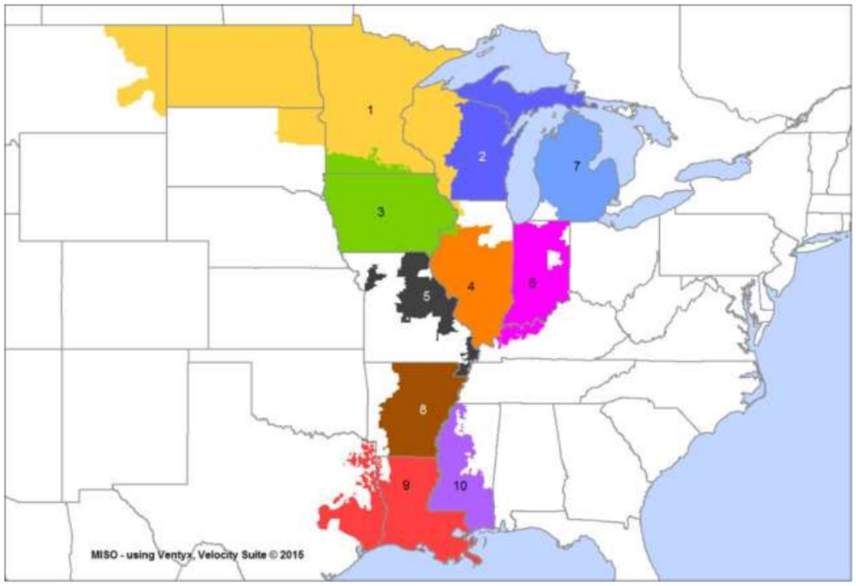
The current wholesale energy market in MISO is a subsection of the Eastern Interconnection, which is the electric transmission grid that spans from the east coast of the United States to the central plains and from the Hudson Bay in Canada to the Gulf of Mexico. Wholesale energy markets, including MISO, rely on a large pool of resources with geographically diverse needs and resources that aim to allow excess resources in one part of the footprint to meet customer demand in another through use of the transmission grid. This diversity helps to mitigate the need to locate generation in close proximity to areas of demand, and can level variability in renewable resources by taking advantage of weather differences across the entire market's footprint.

While today's interconnected grid of transmission facilities reliably transfers large amounts of energy over long distances to meet customer demand, the grid was not originally developed to serve regular (*i.e.,* "base system") customer demand across distant geographies for significant durations throughout the year; nor was it designed to serve customers from densely-sited renewable generation, like it does now. And while these individual systems are interconnected, the there is not sufficient transmission infrastructure to be able to operate the MISO footprint like one of the original utility footprints. Therefore, one of the reliability measures that MISO instituted was to develop Local Resource Zones (LRZ) and inter-LRZ transfer limits to ensure ongoing reliable system operation.

The Figure below portrays the geographic diversity of the current MISO footprint and shows the different LRZs by number and color.

Figure 1: MISO Local Resource Zones

Map of MEP Local Resource Zone Boundaries



Source: Attachment WW of the MISO Tariff.

The NSP System is in LRZ1 along with Dairyland Power Cooperative, Great River Energy, Montana-Dakota Utilities, Minnesota Power, Ottertail Power Company, and Southern Minnesota Municipal Power Association.

This has worked well, however, the fundamental nature of the resource side of the equation is changing, which drastically changes the dynamics on the grid. There are more distributed, intermittent generating sources – and large synchronous generating units are retiring from the system. Inverter-connected resources at high levels of penetration generally do not provide the system services necessary for utilities to operate reliably. Without the inertia from the large generating units, system stability could be compromised – and the system is much more susceptible to the effects from what traditionally would have been inconsequential disturbances. As the level reliance on these interver-based resources continues to increase, new approaches to system planning are needed, as the current state of those processes cannot sufficiently address the differences in these resource types.

II. CURRENT MISO RENEWABLE CAPACITY VALUE DETERMINATIONS

On today's system, MISO has an annual processes to assign capacity values to generating resources that vary by resource type, and that establish resource adequacy requirements for load serving entities such as the Company. These values come from the availability of the resource type as evaluated over a long base of operating experience at a specific hour of the year. The set of resources with specific performance attributes are put into a Loss of Load Expectation (LOLE) study and mixed with simultaneous probabilities (i.e. Monte Carlo type analyses) of when those outages may occur across the grid. This analysis also considers transmission performance capabilities and thus probabilities of loss of a transmission element. These analyses combine to ensure that the chosen resource mix and the specific grid will allow for load to be served to a load loss standard usually of no more than one day loss in 10 years. These capacity valuation mechanisms include the MISO Effective Load Carrying Capability (ELCC) analysis[1] and Wind and Solar Capacity report. The resource capacity values are commonly known as "accredited" amounts of capacity that can be relied upon to meet customer demand for planning purposes. MISO's resource adequacy process also establishes the margin by which the Company's resources are required to exceed demand in order to cover potential uncertainty in the availability of resources or level of demand.

If there are larger amounts of resources with the same performance attributes included in this analysis, the probability of loss of all those resources at the same time increases – and thus, the probability of impact on the load loss standard increases. For transmission for example, a consideration is the proportion of longer lines, which are more susceptible to weather or other types of disruptions, compared to shorter lines. As we discuss in more detail below, this is the reason that higher proportions of intermittent or variable resources erodes the capacity value for *more* of that resource – because the probabiblity of loss increases. Diversity in the type and location of a resource mix has always been important, and that will only become more important as the grid continues to evolve.

MISO's current resource adequacy requirements do not consider this expected marginal decline in load carrying capability from renewables as penetration increases, which we believe could ultimately result in a resource deficiency. The capacity accreditation also does not take into account the seasonal and weather-related variability that we have observed in both winter and summer instances, where renewables have vastly underperformed their expected contribution to load. In these circumstances, firm dispatchable, load supporting resources have been needed to fill the gap. Our Reliability Requirement is intended to recognize this new normal that is emerging. We outline the current MISO processes that determine resource adequacy requirements and capacity accreditation for wind and solar resources below.

[1] ELCC is a measure for estimating a resource's capacity value to meet customer needs with no net change in reliability.

A. Loss of Load Expectation Study

A Loss of Load Expectation (LOLE) study is intended to assess the overall probability that there will be a shortage of power, and is defined as the expected number of days per year for which the available generation capacity is insufficient to serve the demand at least once per day. The MISO LOLE is performed annually, analyzing a two-year horizon. From this study, several threshold requirements used in resource planning efforts are established for the following year – including a margin of resources the Company is required to maintain over and above its expected customer demand. This resource adequacy margin is the amount of generating capacity, over-and-above expected customer load that needs to be present on the system to ensure reliability in all but the most extreme circumstances; this margin does not however, currently account for the intermittent nature of renewable resources. As we describe below, renewable resources are assigned an accredited capacity value based on their annual average contribution to the system peak, rather than their ability to contribute to customer needs every hour of every day.

After these general obligations have been determined, we consider the type of resources suitable to meet that requirement. MISO's tariff and business practices set forth procedures to enable various types of resources to be used to achieve our requirement. These resources are referred to as "Planning Resources," which include the following sub-types:

- *Capacity Resources*: Physical Generation Resources (i.e. physical assets and purchase agreements), External Resources if located outside of MISO's footprint, and Demand Response (DR)resources participating in MISO's energy and operating reserves market, available during emergencies.
- *Load Modifying Resources*: Behind-the-Meter Generation and Demand Resources available during emergencies, which reduces the demand for energy supplies coming from the load-serving entity (LSE).
- *Energy Efficiency Resources*: Installed measures on retail customer facilities designed and tested to achieve a permanent reduction in electric energy usage while maintaining a comparable quality of service.

The Planning Reserve Margin (PRM) process establishes PRM values on both an installed capacity (ICAP) basis, which reflects the nameplate capacity of a resource, and on an unforced capacity (UCAP) basis, which incorporates the resource's operation, maintenance and utilization characteristics. Utility planning for system needs, including the planning we do as part of Minnesota Integrated Resource

Planning process, focuses on UCAP values, so we can plan to the measure of a resource's reliable contribution to system needs.

Physical generating resources and registered DR are assigned a UCAP value by applying a discount to their installed capacity. For a generator, the discount represents its forced outage rate. For DR, MISO uses a documented process of assessing the resource's observed responsiveness and effectiveness at reducing load. Intermittent Resources—including large-scale Solar, Wind, and Hydro–are assigned UCAP values that are determined by the individual unit's historical performance during the peak hours of the planning period.[2] As we discuss above, we are entering a new planning paradigm, and planning for a single system peak will no longer ensure customer reliability.

B. Wind and Solar Capacity Credit Report

Using the data from the LOLE study, MISO creates an annual Wind and Solar Capacity Credit Report that establishes MISO-wide capacity values for all wind and solar resources for the next planning year. MISO currently uses a probabilistic analysis as the first step in determining the ELCC for wind and solar resources. The second portion of the analysis utilizes a deterministic approach using historical wind resource output data, which incorporates the resource location. Combining these two sets of analyses, MISO then aggregates the characteristics to the nearest Commercial Pricing Node (CPNode) to determine a localized Wind Capacity Credit for each CPNode.

The 2018 report utilized installed wind capacity as of June 30, 2018, which included 18,210 MW of nameplate generating capacity assigned to 215 individual CPNodes. The values from this report are intended for incorporation into the following planning year – in this case, 2019. These values are as follows:

- Wind Capacity Credit (MISO system-wide):[3] 15.7%
- Solar Capacity Credit:[4] 50%

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[2] Currently, these units are measured on historical performance during the operating hours of 1500 to 1700 in the months of June-August over the three most recent summers. Each site must have one complete historic period of data prior to unit accreditation.
[3] The calculation of the Wind Capacity Credit is the Individual CPNode Capacity Credit % = Peak Metric * K, where K is the coefficient representing the ratio between the calculated ELCC and the sum of the individual CPNode peak metrics.
[4] As of December 2018, MISO had a registered total of 313 MW of installed solar capacity. Because of the relatively low volume, MISO assigns each new solar unit a 50 percent capacity credit until additional operational data is available.

MISO also conducts studies on an LRZ-level to ensure regional reliability.

C. Relevant Regional Planning Considerations

MISO has the largest geographical footprint of any regional transmission organization. This provides valuable geographic diversity and access to additional resources when needed for back-up purposes. However, there are limitations on the amount of energy that can be shared between LRZs, and the amount of energy that can be imported or exported between MISO and other regional transmission organizations. As a result, MISO has developed localized studies that address the resources needed within each LRZ, as well as the limitations on transferring energy between LRZs, as follows:

- *Local Reliability Requirement.* This value is calculated to determine the amount of resource capacity needed on a LRZ level to ensure reliable service of customer demand during peak usage.
- *Capacity Transfer Limitations.* Capacity Import Limitation (CIL) and Capacity Export Limitation (CEL) values are determined through a capacity transfer study that signals the levels of capacity that can be both imported into a LRZ and exported to a LRZ while maintaining reliability.

Despite its broad geographic diversity, MISO remains susceptible to variations in resource availability based on, among other things, weather. As we have explained, today's interconnected grid is not the same as the traditional utility-specific grids that were built to serve local customer loads. There is not sufficient transmission infrastructure within MISO to transfer any resource type any distance – nor can it import limitless resources from other regional grids. Weather has taken out all of a certain type of resource – specifically wind, in the case of the 2019 polar vortex. Similarly, a day in July 2018 was an especially windless day and in one hour, the wind turbines that were online were taking more power than they were producing. This hour was also part of an approximately *110 hour* sustained stretch in which the combined output of all wind resources in the MISO footprint fell well below the accredited values used in present planning processes.

Individual utilities therefore must consider what level of reliance on the MISO market is reasonable to fulfill their system needs without exposing their customers to potential shortfalls or high prices, particularly in the event of high system stress conditions. We take our responsibility to ensure we have access to a sufficient level of resources in all grid conditions to meet our customers' needs seriously. The future

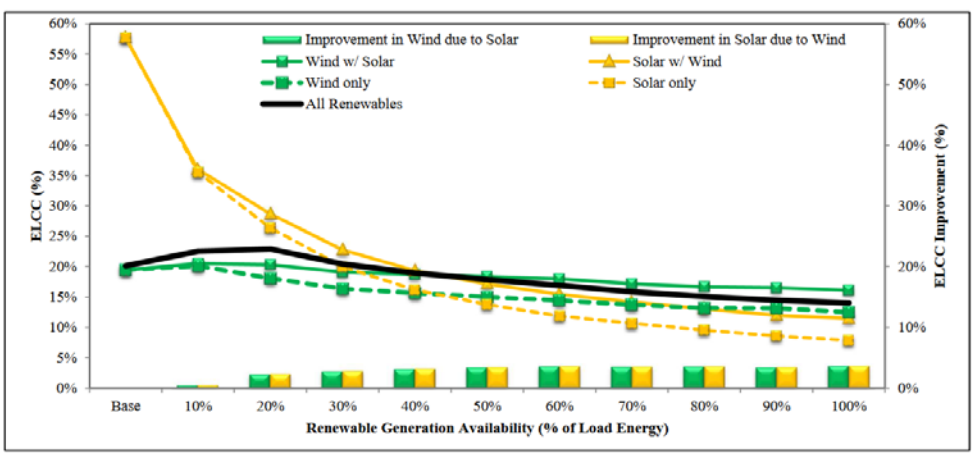
MISO grid will rebalance the new resource mix and the new transmission configuration needed to support it. We expect there will be many transitional stages between now and then to achieve this resource shift reliably. Determining our level of market reliance as part of our Reliability Requirement is a necessary part of this transition.

III. HIGH LEVELS OF RENEWABLES RESULT IN DECLINING CAPACITY VALUE

The industry is beginning to recognize and adapt planning processes to incorporate declining capacity values for wind and solar resources as penetration levels increase. However, MISO has not yet changed its planning processes to account for these limitations.

In 2017, MISO initiated its *Renewable Integration Impact Assessment* (RIIA) to examine issues surrounding effective integration of high levels of renewable resources. The figure shown below is an excerpt from an April 18, 2018 MISO presentation showing that, as wind and solar approach 100 percent penetration, their ELCC values decline significantly and approach 10 percent. When the generation fleet is diversified by including both wind and solar, the relative ELCC value for each is higher, but there is still a significant decrease in value as combined penetration approaches 100 percent.

**Figure 2: MISO RIIA Study Finding –
Declining ELCC Value for Wind and Solar Resources**



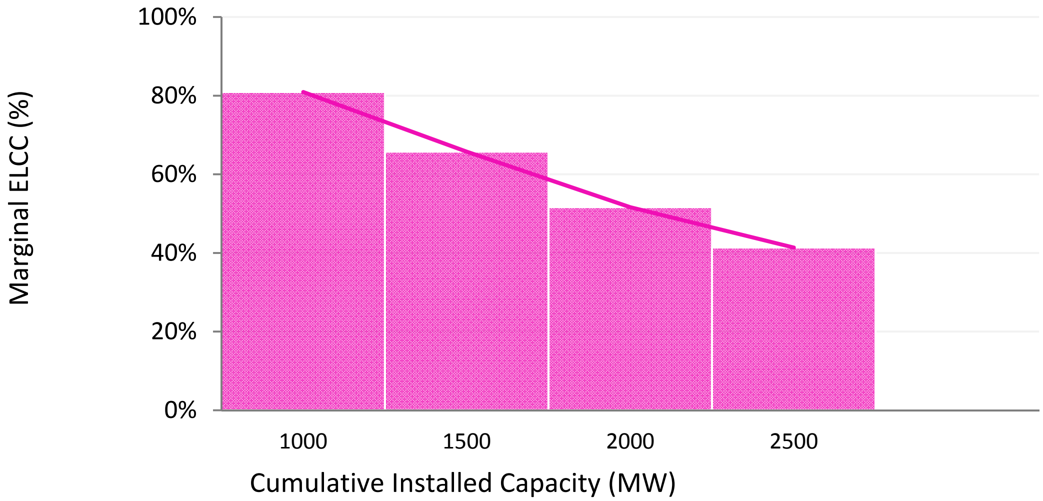
Source: MISO April 18, 2018 RIIA presentation at page 8.[5]

Notably, solar and wind are not the only resources whose capacity values decrease as

[5] https://cdn.misoenergy.org/20180418%20PAC%20Item%2003d%20RIIA174068.pdf

penetration increases. As shown in the analysis performed by E3 in connection with this Resource Plan, demand management programs also have decreasing relative effectiveness as participation increases.

Figure 3: E3 Marginal ELCC (%) – Four-Hour Demand Response



Source: E3 RECAP Analysis

Although early in the process and mainly focusing on their Resource Availability and Need (RAN) initiative,[6] MISO also recognizes that its current approach of using historical load shapes to predict the long-term future is no longer sufficient as Distributed Energy Resources (DER), Demand Response (DR), and energy efficiency become more prevalent. MISO likewise acknowledges that impact of these resources on demand, energy, and corresponding load shapes needs to be better understood and accounted for in its planning construct.

IV. RECENT ACTUAL LOW RENEWABLES PERFORMANCE EVENTS

In addition to these future planning – or accreditation – limitations, the actual performance of renewable resources reveals certain limitations with their ability to ensure reliability under all conditions and at all times without the support of some amount of dispatchable generation. To show this, we consider a number of actual case studies from the last 12 months below.

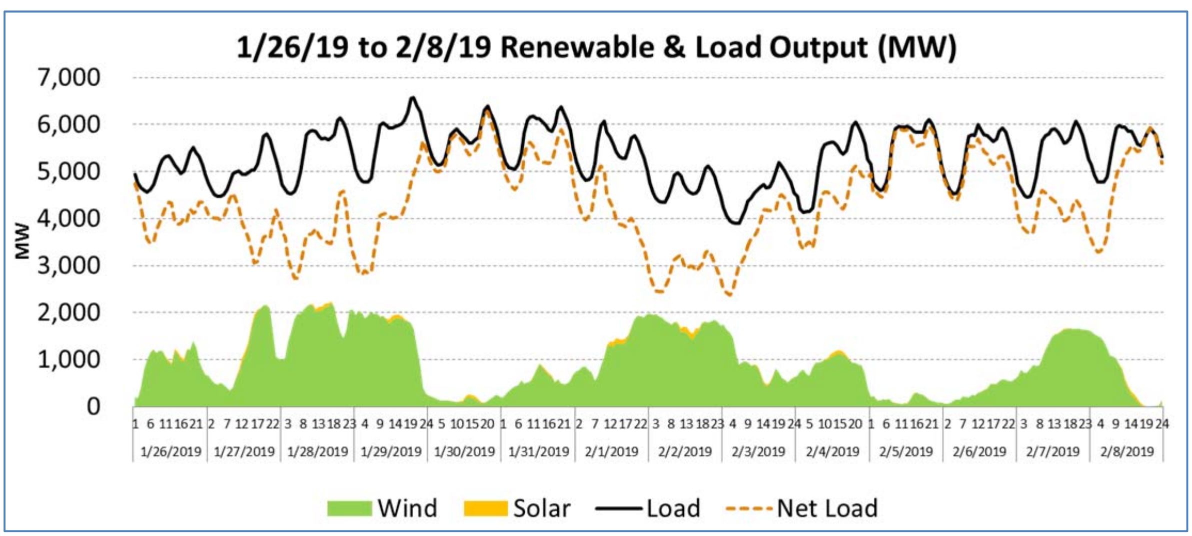
[6] The purpose of the MISO RAN initiative is to assure the conversion of committed capacity resources into sufficient energy every hour of the Planning Year.

A. Winter Case Study Events

In the past, winter months traditionally matched well with renewable resource production. In winter, we typically experience lower system demand and increased transfer capabilities, (meaning the ability to effectively transfer large amounts of renewable energy from where it is produced to load centers such as the Twin Cities Metro area). Additionally, wind resources generally achieve their highest efficiencies of the year over the winter months. However, as the penetration of renewable resources in the Company's fleet has increased and taken on a growing role in base energy production, winter has become an increasing concern. As we discuss below, during the 2019 polar vortex and an otherwise "normal" winter (and summer) day, firm dispatchable resources were needed to fill sustained periods of time where renewable resources were not producing at their accredited levels.

Given the variability of renewable generation, we have encountered times when the net customer load (which is the amount of customer demand not being met by renewable generation and for which firm dispatchable resources are needed) is near, or even equal to, the gross demand on the system. As shown below, this was the case during both the January 29-31, 2019 polar vortex, which was an extreme weather event marked by historically-severe and sustained cold temperatures combined with high winds, as well as February 5, 2019, a normal winter peak period.

Figure 4: Renewable Output and Load
January 26 – February 8, 2019



This illustrates why planning for a single system peak no longer works. We have to also plan to meet our customers' energy requirements on a net load basis – or the gap between customer needs and variable resource availability every hour of every day.

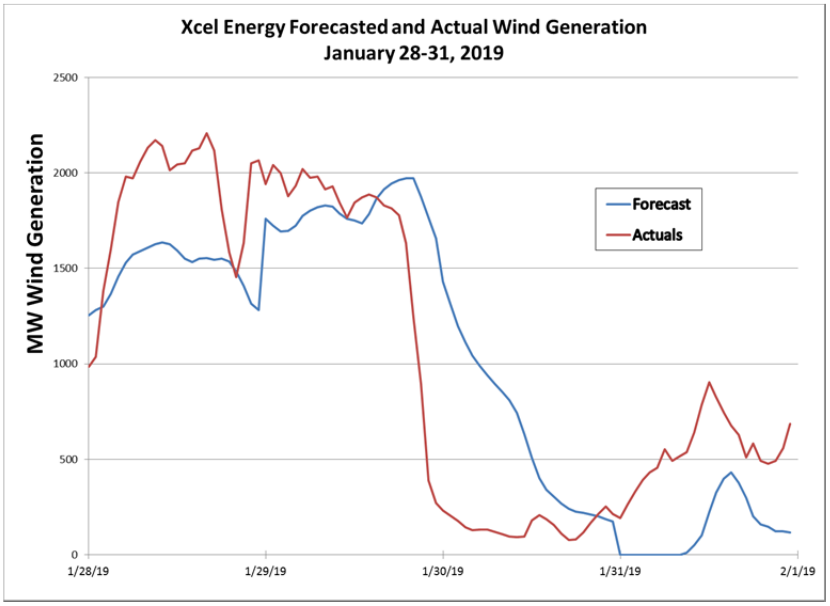
1. *Extreme/Polar Vortex Event*

The January 28 to February 1, 2019 timeframe, referred-to as the 2019 Polar Vortex, was marked by extreme cold temperatures over a sustained period of time across the northern United States, and specifically within the MISO footprint. The MISO region experienced ambient temperatures well below zero degrees Fahrenheit (F) for several consecutive days, with temperatures falling well below -20 degrees F in some areas. During this period, MISO experienced a resource deficiency and relied upon external resources and load control measures to reliably operate the system and balance generation resources with customer demand. Due to the duration and magnitude of the resource shortfall, neither DR nor energy storage could substantially contribute to reducing the Net Load.

The overwhelming majority of wind turbines now have operating temperature cutoffs at approximately -22 degrees F. MISO, however, did not have established measures to account for these limitations. As a result, and because of the high wind speeds during the polar vortex event, the MISO wind forecast projected upwards of 14 GW of wind generation to be online. However, the vast majority of wind turbines shut down in the early morning hours of January 30th, and output dropped to approximately 3 GW sooner than the forecast had predicted. As a result, firm dispatchable resources were needed to fill the gap left by the lack of wind.

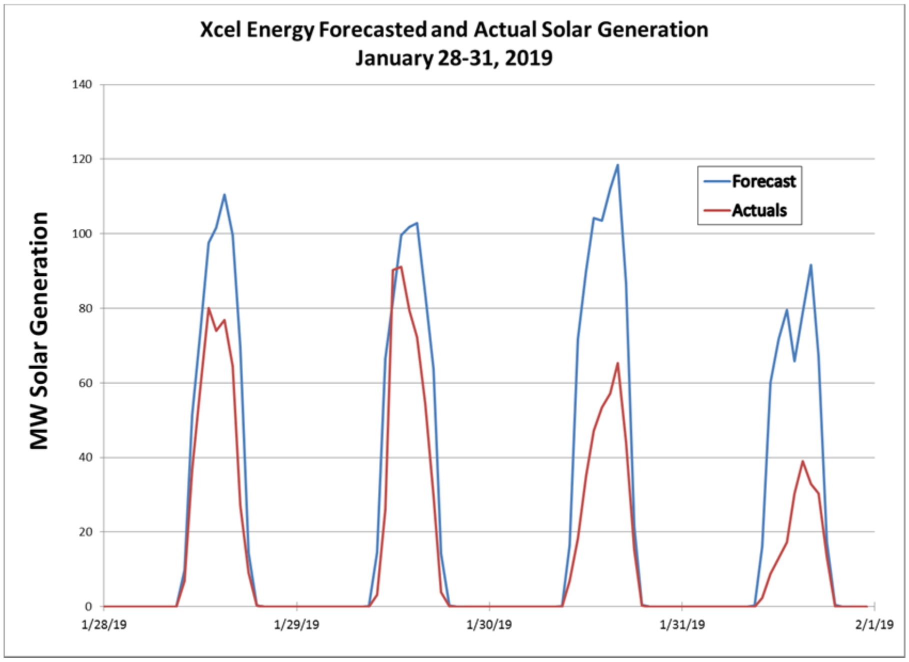
Figure 5 below shows the Xcel Energy wind actuals compared to the forecast during this period, which we note closely mirrored the MISO forecast and actuals.

**Figure 5: Xcel Energy Wind Generation Actuals vs. Forecast
January 28-31, 2019**



Solar generation performance is also affected by temperature, but does not involve cold weather cut-offs. Rather, solar panel efficiency drops off steadily once *panel* temperatures exceed approximately 42 degrees Celsius (107 Farenheit). Panel temperatures are typically approximately 20 degrees Celsius higher than the ambient air temperatures, thus solar production efficiency starts to decline when the ambient air temperature is in the range of 87-91 degrees Farenheit. PV Solar panel production works most efficiently during cold temperatures, with the obvious caveat that cloud cover and/or snow on the panels will reduce solar generation. We provide as Figure 6 below, a comparison of the Xcel Energy solar actuals compared to the forecast during the polar vortex period.

Figure 6: Xcel Energy Solar Generation Actuals vs. Forecast January 28-31, 2019



This solar forecast compared to actuals chart indicates a forecast error, especially for the last two days of the period. Our meteorologists attribute the error to a snow event at one of our larger solar facilities, where the conditions at the time were like those shown in Figure 7 below.

Figure 7: Snow Impacting a Large Solar Installation

Essentially, the solar panels that can "track" the sun are are built to maximize solar generation by continuously finding the optimal sun angle. Due to heavy snow in this situation, the panels were unable to move and the angle was insufficient to shed the snow cover, thus affecting actual production and not matching our forecast. In fixed-axis solar resources, there are options: (1) optimize to shed snow cover, which reduces the ability of that resource to produce energy; and, (2) optimize to output the most energy, which reduces its ability to shed snow cover. As we discuss below, winter solar performance is also affected by fewer light hours/shorter days and less optimal sun angles.

According to a report compiled by the MISO Independent Market Monitor (IMM), during this timeframe the MISO footprint used resource "reserves," which consisted of non-firm resources offered by neighboring regional transmission organizations into the MISO market. The level of these resources that MISO had to use to remain operational and avoid further emergency actions ranged from 5,000 MW to 11,500 MW – with an average of 6,500 MW on January 30th. The maximum offered reserve resources was 13,500 MW, which MISO nearly exhausted at one point in order to avoid a critical deficiency in available energy.

Although extreme, this weather event may reasonably be expected to occur again, and a disruption in electric service during a similar event in the future would have detrimental and serious impacts on our customers and public safety in general. We therefore believe this case study provides an important, recent example to consider as we manage the transformation of our generation portfolio while prioritizing the reliability and stability of our system.

2. *Normal Winter Day*

In addition to cold temperatures affecting wind production, snow cover and icing also decrease wind and solar output in winter months; non-ideal sun angles and shorter days, and thus limited light hours, additionally impact solar production. While the polar vortex involved extreme weather conditions that affected wind production especially, February 5, 2019 was a normal winter day that offers another example where Gross Load was at, or near, Net Load (Gross Load minus contributing renewable resources) for a significant number of hours.

Between 7:00 a.m. and 11:00 p.m., there were 16 consecutive hours where Net Load was over 5,400 MW. Due to the duration and magnitude of this shortfall, neither DR nor energy storage could substantially contribute to reducing the Net Load, at least for the entire period. During this period, all wind and solar resources on the system combined to have an average hourly capacity factor of *six* percent, and there were particular hours when neither wind nor solar resources had a capacity factor greater than *three* percent. We provide the hourly capacity factors for wind and solar resources below.

Table 1: Hourly Wind and Solar Capacity Factors
February 5, 2019

Hour Ending	Wind Capacity Factor	Solar Capacity Factor
1	9%	0%
2	9%	0%
3	6%	0%
4	5%	0%
5	7%	0%
6	6%	0%
7	7%	0%
8	4%	0%
9	3%	0%
10	3%	3%
11	2%	6%
12	3%	6%
13	3%	5%
14	7%	5%
15	12%	4%
16	13%	2%
17	11%	1%
18	11%	0%
19	9%	0%
20	6%	0%
21	5%	0%
22	4%	0%
23	3%	0%
24	4%	0%

Because we currently have access to sufficient baseload and firm dispatchable resources on our system, we were able to serve customers reliably and affordably throughout the duration of this period.

3. Other Winter Conditions

In considering the resources available during periods of low wind generation, the Company also needs to assess availability of resources across MISO. The MISO footprint encompasses large areas that experience snow cover and extreme low temperatures in the winter months. This impacts the output of renewable resources throughout MISO in several ways.

Wind turbines are designed to cut-out at extreme cold temperatures to protect their operational mechanisms. During the 2019 Polar Vortex, temperatures dropped below the -22 degree F cutoff, causing wide-spread reduction of wind resources despite relatively high wind speeds.

Snow cover and icing negatively impact solar and wind generation resources. As discussed above, during the winter months in the Upper Midwest, snow and ice cover on solar panels significantly decreases the energy capabilities of those resources. Wind turbines are susceptible to blade icing, which causes decreased output or complete cessation. While these issues are limited to certain geographical areas, those same areas highly correlate with the most dense and highest average capacity-factor renewable resources in the MISO footprint.

Limited light hours combined with non-ideal sun angles reduce the output of solar resources in winter months. These conditions are prevalent throughout the MISO footprint, which combine to reduce the output of solar resources to fewer hours of the day, and lower levels of energy output when the sun is available.

B. Normal Winter Day Case Study Extrapolated to Higher Levels of Renewables

Consistent with our vision for 100 percent carbon-free energy in 2050, we studied these scenarios with higher levels of renewable resources than exist today. To do so, we replicated the operational scenarios encountered on February 5, 2019, but modeled with 5,000 MW of nameplate capacity wind and 5,000 MW of nameplate capacity solar resources. The results were very similar. For 13 of the 16 hours, the Net Load remained above 5,300 MW and all hours exceeded 5,000 MW of Net Load.

C. Non-Winter Case Study Event

Because low temperatures and other conditions unique to winter are not the only cause of low renewable generation in MISO, we also looked to the summer months as potential case studies. July 29, 2018 was an especially windless day. During the 8:00 a.m. hour, the entire MISO wind portfolio (over 17,000 MW at that time) had a combined output of *minus* 11 MW – meaning the wind turbines that were online were taking more power than they were producing. This hour was part of an approximately *110 hour* sustained stretch in which the combined output of all wind resources in the MISO footprint fell well below the accredited values used in present planning processes. We again encountered sustained low wind conditions in early 2019, with 370 hours of wind production below accredited values before May 1.

These case studies are supported by a recent University of Minnesota Research Brief about an initiative that examined conversion of home heating from gas to electricity – and supplying that electricity with renewable energy, which had been identified as a critical national decarbonization pathway.[7] The May 8, 2019 *Research Brief: Planning for the future of energy demand with renewable energy* reported that researchers at the University of Minnesota and three other institutions sought to understand whether enough renewable energy can be generated locally to meet most, if not all, of that increased electricity demand.

Researchers mapped out three scenarios: one that included battery and thermal energy storage options; an option that assumes no storage; and an option that overbuilds renewable supply by 150 percent of demand. They then ran models using data from four cities in three different climate zones, including Minneapolis, Minnesota.[8] The study found that for scenarios without storage, wind-based supply dominates the optimal mix for Minneapolis. The study also found that when 12-hour storage is available, renewable penetration increases from 54 percent to 70 percent in Minneapolis. In light of these findings, the Brief stated:

> However, no matter the scenario, the study found that the use of fossil fuels would still be needed to meet peak demand in cold climates like Minneapolis and Fort Collins. This is because renewable energy cannot be produced at the rate needed to meet demand during the coldest months..

Finally, the Brief reported that researchers suggest policymakers and/or low carbon energy system planners do the following:

- Take into account the geographic and climatic differences when finding the optimal mix of wind and solar generation,
- Consider incentives to invest in battery storage systems, which will increase the overall amount of demand that can be met with renewables,
- Count on a smaller, but nonetheless important, role for fossil fuel plants to meet peak demand.

V. KEY TAKEAWAYS

As this data shows, today's intermittent generating resources cannot alone meet

[7] *See* https://twin-cities.umn.edu/news-events/research-brief-planning-future-energy-demand-renewable-energy

[8] Other cities were New York City, New York, Fort Collins, Colorado, and Tallahassee, Florida.

demand at all times of the year, at least without excessive costs.[9] Even during historically good times of the year for renewable generation on the Company's system, the availability of these resources is inexorably tied to the variability of weather patterns, and at times they are simply not available.

Additionally, current storage technologies and demand management programs are also insufficient to meet the duration of real events like those discussed above. Current battery storage systems are limited (typically to 4 hour discharge periods) with significant time needed to recharge. Unless overbuilt many times over, these resources would not be able to provide energy for the full duration of such events; they also may not be able to recharge fast enough to be a viable resource during the consecutive periods of low renewable output. Similarly, and as discussed above, some of the most significant current demand management programs are specifically designed to reduce capacity needs during the system's overall peak during summer hours, and they would not be as effective, or effective at all, during winter periods.

These case studies and industry insights have highlighted gaps in present MISO planning constructs that – until MISO adapts – we must take into account to ensure system resilience and customer reliability. Fundamentally, we have a responsibility to ensure we have access to a sufficient level of firm dispatchable resources in all grid conditions that can flexibly adapt to variable renewable resource performance to meet our customers' needs. We take this responsibility seriously. We view these case studies as highlighting gaps in the present MISO planning construct. Until MISO determines how best to address these gaps, we believe it is incumbent on us as the utility to take steps to ensure that our system is resilient, that our customers will be reliably served, and that our customers are reasonably protected from high financial exposure in the market when the system is under stress.

VI. DEVELOPING THE RELIABILITY REQUIREMENT

In an effort to mitigate resilience and reliability risks, we analyzed the data from these case studies and created a reliability requirement for our modeling that reflects a reasonable amount of reliance on MISO resources and demand response to meet our system needs. The intent of this requirement is to supplement our system planning process to ensure we have sufficient resources available to reliably serve our

[9] Simply increasing the amount of solar and wind generation on the Company's system is an unrealistic approach to addressing capacity shortfalls. In order to have sufficient capacity to meet the customer demand discussed in the scenarios above, the Company would need in excess of 180,000 MW of nameplate capacity wind and solar generation. And, even this amount of renewable generation may be insufficient given the declining capacity value of renewable generation, as discussed above, and the probability there will be times with extremely low levels of wind and sunlight.

customers' energy needs every hour of every day – regardless of weather.

Establishing this reliability requirement involves a number of steps:

1. Establishing a level of peak demand to serve as a proxy for the most likely conditions where we would expect to have a gap between renewables performance and customer load.
2. Assessing the contribution we can reasonably expect from duration-limited resources like DR or energy storage to fill-in the gap.
3. Determining the extent to which it is reasonable, from a financial and operational risk perspective, to rely on the MISO market to make-up at least a portion of the gap.
4. Using these inputs to derive the level, of firm dispatchable resources that are needed to reasonably assure reliability. It is this level of firm dispatchable resources that ultimately forms the Reliability Requirement that we incorporated into our modeling for this Resource Plan.

We discuss the components of this calculation below.

A. Proxy Peak Demand

The first step in determining the Reliability Requirement was to approximate the customer peak demand we should expect during inevitable high stress MISO market scenarios. Although winter is not the only season in which we have experienced low renewable output relative to expected contributions, it is when we most expect weather conditions to impact wind turbine and solar panel performance (i.e. blade icing and snow cover). We therefore determined that the NSP System winter peak demand – or approximately 6,400 MW – would be an appropriate proxy and starting point to ultimately determine the resource types and amounts that we can reasonably rely on to fill the gap.

B. The Role of Duration-Limited Resources

Today, the Company is able to draw on DR and likely in the future, other time-limited resources such as storage to meet our customer needs. But, while these resources can help fill the gap to some extent, it would not be prudent or practical to fully rely on them to guarantee system reliability.

As discussed above, demand management programs have lower availability in winter months. As with all components of the Reliability Requirement, the DR proxy was designed to avoid unrealistic assumptions of demand response availability. This proxy, therefore, allows for the support of demand management programs up to the point where they can no longer be considered firm resources. We included a demand response proxy of approximately 200 MW in our modeling.

C. MISO Market Reliance

As noted above, resources from the MISO market may also be available to fill the gap between customer load and low renewables performance, although transfers within and between LRZs are constrained in accordance with MISO's identified system capabilities. This is a valuable benefit of being part of a regional market. However, we expect that that other resources and loads in MISO and LRZ1 will experience similar conditions – particularly if an event is weather-related. We do not believe it would be reasonable or in our customers' best interest to rely on the market to fulfill the resource gaps caused by the unavailability of intermittent resources – especially in high-stress scenarios. It is therefore important to determine an appropriate and reasonable level of reliance on market resources during a high-stress scenario. Notably, these high stress times frequently happen in periods of extreme cold when our system is even more critical than normal. This market reliance issue will only become more important as utilities retire firm dispatchable resources that today aid reliability during these times of system stress.

Using a combination of MISO planning data and the IMM analysis of excess resources during the 2019 Polar Vortex event, we derived a level of MISO market reliance for the NSP System to incorporate into our RRP calculation.

Table 2: Planning Parameters to Derive NSP System Level of Market Reliance – High Stress Scenarios

Relevant Planning Parameter	2019-2020 Planning Year Values
MISO Peak Demand	125,501 MW
LRZ1 Peak Demand	17,780 MW
NSP System Peak Demand	9,129 MW
NSP System Peak as Percent of MISO	*7.27%*
NSP System Peak as Percent of LRZ1	*51.3%*
Polar Vortex Event – Minimum Excess Resources	5,000 MW
Polar Vortex Event – Average Excess Resources	6,500 MW
NSP System Share of Excess Resources (7.27% of Min. and Avg. Excess Resources)	364-473 MW
NSP System Market Reliance Level	**500 MW**

From the IMM analysis of the 2019 Polar Vortex event, we know the minimum (5,000 MW) and the average (6,500 MW) MISO-wide excess resources that were used during this event. These are important values to understand, as they were the level of excess non-firm resources made available from outside of MISO and needed by MISO to avoid a critical energy deficiency.

If similar operational events and system demands were experienced across large areas of the full MISO footprint during a high-stress event, and assuming that reliance on external resources would be split based roughly on each utility's portion of total demand, the Company would be able to rely on only 7.27 percent of any excess generation in the MISO system. Therefore, to derive the NSP System share, we applied the NSP System load ratio share to the minimum and average levels of excess resources from this event, which equates to a minimum of 364 MW and an average of 473 MW. From here, we assumed some additional customer efficiency might lower our peak or operational efficiencies might increase external energy available to the NSP System, and thus determined that 500 MW would be a reasonable level of MISO market reliance during a high stress scenario.

After approximating the contribution from these sources, we are able to determine the quantity of firm, dispatchable resources we need to maintain on the NSP System to assure reliability.

D. Some Level of Load Supporting Resources are Needed

The calculation of the Reliability Requirement results in a minimum level of firm dispatchable resources necessary to adequately support customer loads. We discuss how we apply the Requirement to our modeling in Chapter 3: Minimum System Needs. We clarify here however, that while this concept is essential until MISO evolves its capacity construct, the Requirement has little effect in our modeling for this Resource Plan. The model does not select any firm dispatchable additions as a direct result of the Reliability Requirement until 2031, which is near the end of the planning period. This long runway leaves ample time for MISO and its stakeholders to address this aspect of its planning and provide additional direction.

That said, we demonstrate the calculation of the Requirement we applied in our modeling for this Plan in Figure 8 below.

Figure 8: NSP System Reliability Requirement Calculation – 2020 Example

Peak Demand Proxy – 6,400 MW
Minus Firm DR (Winter) Proxy – (200 MW)
Minus Firm Market Supply Proxy – (500 MW)

Reliability Requirement – 5,700MW
(Firm dispatchable resources)

We are confident that this is a reasonable and appropriate approach to determining a minimum level of firm dispatchable, load supporting resources necessary to maintain a reliable supply of power during high-impact low-frequency events like the 2019 Polar Vortex – as well as other typical summer or winter weather days that happen to have low renewable performance.

VII. SUMMARY

As the Company increases the amount of renewable generation in our system, it is important to recognize that these resources cannot alone reliably provide customers the energy they demand every hour of every day – or maintain the stability of the grid. MISO is beginning to recognize these challenges and that its current planning constructs do not yet address these issues. In the interim, our Reliability Requirement ensures we have the right mix of resources on our system every hour of every day to meet our customers' needs.

PUBLIC DOCUMENT
NOT PUBLIC DATA EXCISED

Attachment J3 is marked as "Non-Public" in its entirety and is provided with Critical Energy Infrastructure Information (CEII) redacted. Attachment J3 contains information regarding the MISO area grid, including specific information about the Xcel Energy and other transmission owner systems as it relates to the potential retirement of Xcel Energy's Allen S. King and Sherburne County Generating Plant (Sherco) Unit 3. While MISO has redacted all CEII from the report, Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by MISO.
3. **Importance:** The study contains security information.
4. **Date the Information was Prepared**: The study was finalized November 14, 2018

NOT PUBLIC DATA EXCISED

PUBLIC DOCUMENT
NOT PUBLIC DATA EXCISED

Attachment J4 is marked as "Non-Public" in its entirety and contain redactions to CEII for the same reasons noted for Attachment J3. Xcel Energy maintains that the balance of the information is "security information" as defined by Minn. Stat. § 13.37, subd. 1(a).

Pursuant to Minn. R. 7829.0500, subp. 3, the Company provides the following description of the excised material:

1. **Nature of the Material**: Prepared study.
2. **Authors:** The study was prepared by MISO.
3. **Importance:** The study contains security information.
4. **Date the Information was Prepared**: The study was finalized November 27, 2018

NOT PUBLIC DATA EXCISED

APPENDIX K – XCEL ENERGY RESOURCES: NUCLEAR

I. NUCLEAR

Carbon-free nuclear generation has been a cornerstone of our generation fleet for nearly fifty years, and its continued role on our system is critical to ensuring that we continue to make progress in reducing our carbon emissions. Our Preferred Plan therefore includes the extension of operations at the Monticello nuclear plant until 2040, along with the continued operation of Prairie Island through its current operating licenses (which expire outside the planning period in 2033 and 2034). By continuing the operation of these plants and extending our Monticello license, we can continue to drive the substantial carbon-free benefits that our nuclear fleet provides while saving our customers money by leveraging existing assets on our system that are leading the industry in terms of performance.

In this section, we discuss the importance of our nuclear generation fleet to our environmental and resource planning objectives. We also provide an update on the strong performance of our nuclear fleet since our 2015 Resource Plan, as well as our capital and O&M forecasts, and we discuss the results of our Strategist modeling in connection with our nuclear strategy. Finally, we discuss the economic, community, and employment benefits associated with relicensing Monticello, and we outline the regulatory processes associated with relicensing at the NRC and seeking authorization from this Commission to obtain additional dry fuel storage capacity to support extended operations.

A. Nuclear's Role in Reducing Carbon Emissions

Xcel Energy has been on the path toward significant carbon reduction for more than a decade and, since 2005, we have reduced carbon emissions 38 percent company-wide. In order to achieve our goal of an 80 percent reduction of carbon emissions by 2030, we need to retire our coal-fired generation before 2030, replace those assets with low- or no-carbon resources, and preserve the carbon-free generation that is already part of our system. Our Monticello and Prairie Island nuclear plants—which total 1,688 MWs in baseload capacity—comprise more than half of our existing carbon-free generation and one-third of our total generation. Our reliance on these plants avoids the emission of 7 million tons of carbon dioxide each year, which is equivalent to removing 1.5 million cars from the road (or more than 20 percent of all registered vehicles in Minnesota as of 2016).

The Company simply cannot achieve similar levels of carbon reduction without nuclear generation on our system. As discussed in our Baseload Study, we will need a significant amount of firm dispatchable generation on our system in order to ensure around-the-clock reliability as we move toward a portfolio that is predominantly renewable and intermittent. We therefore believe any near- or medium-term replacement of our nuclear resources would require some amount of incremental natural gas generation, which would negatively impact our progress on reducing carbon emissions. Moreover, given MISO's current transmission expansion issues, it is far from certain that we could get sufficient renewable projects through the MISO queue in time to replace our nuclear resources. And even if that were possible, it would require substantial renewable additions beyond those already contemplated in our plan, along with supporting transmission infrastructure. Replacing the carbon free energy from Monticello with renewable resources would require over 1,000 MW of wind or nearly 3,000 MW of solar resources along with $400 million in additional transmission investment based on our Resource Plan assumptions. Additionally, these energy only replacement estimates do not account for additional capacity costs that may be required to firm the renewable replacement or local reliability costs that would be required in the event of a Monticello retirement. The costs of adding these resources would have a significant impact on the overall cost of our Preferred Plan and would very likely jeopardize our ability to achieve the carbon reductions we envision.

We recognize that technological developments like energy storage hold great promise and that reliable, renewable baseload energy may be on the horizon. Like others, we are excited by storage technology and its potential to further transform our system, and we are taking steps as part of this Resource Plan to ensure that we are prepared to take full advantage of better technology in the future. But these technologies are still developing and, while approaching economic on a smaller scale, are not yet economic at a scale amounting to even a fraction of our nuclear fleet. For this reason, we view nuclear as a resource that will facilitate our transition to even greater renewable generation and storage opportunities in the longer term, while we continue to pursue aggressive carbon reduction in the near-term.

Meanwhile, our nuclear fleet adds important diversity to our generation portfolio and provides a hedge against not only gas price volatility but also the uncertainty of technological development, future renewable pricing, and the future of solar capacity values. It is also a critical piece of our reliability requirement, as it is not a fuel limited resource, is not subject to pipeline limitations during the winter season, and has a strong operating history during cold (and hot) weather events. Indeed, our nuclear fleet operated at 100 percent capacity factor from January through April of 2018 and again in early 2019 during the Polar Vortex, before Monticello began to coast down in advance of its April refueling outage. Similarly, the summer months of 2018 and thus far of 2019 saw the nuclear fleet operating at full power during peak summer loads.

B. Flexible Operations Pilot

In addition to providing the carbon-free baseload energy we have relied upon for nearly 50 years, we also believe our nuclear units can be operated more flexibly in the future to complement a generation portfolio that will be predominantly renewable. In fact, we are currently piloting an operational strategy to reduce the power output of our nuclear plants when wind and solar resources are generating significant energy.[1] Historically, natural gas plants and, more recently, coal units have been "ramped" up and down to balance energy demands with the amount of renewable energy available on the system at a given time. For decades, nuclear plants have been considered "must-run" baseload power in the context of the MISO regional power market, and we therefore have focused on running at maximum power around the clock. Today, given the increasing additions of renewable resources on our system, we believe our nuclear plants can provide additional value if they can be ramped down during periods of high congestion and low prices. By doing so, the Company can take full advantage of the renewable resources on its system—both now and in the future—and can deliver even greater value from our carbon-free nuclear plants.

[1] We are also part of an industry working group on Flexible Power Operations at EPRI to gain insight from around the industry on this issue.

In 2018, the Company launched an initiative to demonstrate our nuclear fleet's ability to enter MISO's "Day Ahead" market and successfully maneuver one unit at Prairie Island between 75 percent and 100 percent power. Working with MISO, Prairie Island Unit 2 maneuvered through a series of power adjustment and simulated its participation in the Day-Ahead market, and we have since demonstrated similar operational flexibility at Prairie Island Unit 1 and Monticello. In fact, Prairie Island Unit 1 is already participating in the MISO Day Ahead market, and we expect Monticello to join that market in September and Prairie Island Unit 2 to join it in the fall after its refueling outage. In total, this means we will be able to ramp our nuclear fleet by approximately 400 MW, which will add significant operational flexibility to our overall fleet.

We believe the timing of this transition in our nuclear operations is aligned with the Company's plans to incorporate significant wind additions over the next two years, as we complete the build-out of our 1,550 MW Wind Portfolio and our Dakota Range facility. Nuclear has proven its value as the foundation of our baseload fleet, and its carbon-free generation make it a critical part of our plan to achieve an 80 percent reduction in carbon emissions by 2030. We view flexible power operations as an expansion of nuclear's role in our fleet and in the Company's efforts to integrate substantial amounts of renewable additions during the planning period.[2]

C. Performance & Costs

More than ever, we understand that the future of our nuclear fleet depends on our ability to deliver performance at a reasonable cost. Since our 2015 Resource Plan, we have undertaken substantial efforts to adopt wide-scale changes in the way we approach plant operations —with the goal of "bending the cost curve". And with the assistance of third-party consultants with expertise in both nuclear operations and general cost containment and efficiency strategies, as well as our continued work with the Institute of Nuclear Power Operations (INPO) and Nuclear Energy Institute (NEI), we have achieved industry-leading results not only in the performance of our

[2] We are also in the early stages of exploring the possibility of using nuclear energy to produce hydrogen, which in turn could be used both in the transportation sector and as energy storage. Xcel Energy has partnered with two other utilities to explore the economics and overall feasibility of nuclear-driven hydrogen production, and an $8 million funding request is currently pending with the Department of Energy's Light Water Reactor Sustainability Group.

nuclear plants but also in the costs we are investing to achieve that performance. In short, our nuclear plants have never operated on a more consistent, efficient, and safe basis.

1. Safety

Beginning with safety, the NRC Reactor Oversight Process classifies U.S. nuclear reactors into various "Columns," which range from 1 (best) to 5 (worst). Both Monticello and Prairie Island are Column 1 plants with all green performance indicators. And while no plant can achieve the standards of perfection imposed by the NRC at all times over its operational life, we believe our track record demonstrates the Company's longstanding commitment to nuclear safety. Further, during the 2R30 refueling outage in 2017, Prairie Island achieved its best industrial safety record (no OSHA or First Aid injuries) and the lowest occupational radiation exposure in plant history, and both plants have received the Governor's annual safety award for several years running.

2. Capacity Factor

With respect to plant availability, Monticello achieved an average capacity factor of 96.5 percent over the past three years, including a record-setting 99.3 percent in 2018. Likewise, Prairie Island achieved a combined average capacity factor of more than 90 percent over the past three years, including a 100 percent capacity factor for Unit 2 in 2018. This data reflects strong and improved performance at both plants, and the increased availability of our plants drives substantial customer benefits given the fixed costs associated with nuclear fuel. Contributing to these capacity factors was improved performance during plant refueling outages, which were completed on time and on budget. For example, in 2017, Prairie Island's Unit 2 achieved a 37-day refueling outage, which is that unit's shortest refueling duration in 10 years. Likewise, we have experienced some of the longest runs of uninterrupted operation in the history of our nuclear fleet, including a record-setting 499 days at Prairie Island Unit 1 in 2016-2017, and a current run of 583 days (as of June 27, 2019) at Prairie Island Unit 2. In fact, Prairie Island Unit 2 is currently on the third longest run in plant history.

3. O&M and Production Costs

Importantly, we have achieved these safety and operational results without increasing our production costs. In fact, both O&M and total production costs at our plants have decreased significantly in recent years. Total O&M for our nuclear fleet went down by $7 million between 2015 and 2016. It then decreased again by another $26 million in 2017, and decreased yet again in 2018 by another $8 million.

In terms of production costs (fuel plus O&M) per MWh, we achieved reductions of more than 20 percent between 2015 and 2018.[3] Specifically, our fleet average nuclear production costs have gone from $37.86 per MWh in 2015 down to $29.44 in 2018 (Prairie Island has gone from $37.08 down to $28.53, and Monticello has gone from $39.11 down to $30.91).

Contributing to these results has been Xcel Energy's commitment to driving efficiency through its XE1 initiative, which focused on process development and refinement and the integration of technology to achieve efficiencies. Industry experience shows that successful nuclear organizations are highly process and outcome driven and that focused process improvement has the benefit of driving down costs while at the same time improving plant performance. Through our work with the external consultants and INPO, we have been able to effectively improve upon a number of processes and personnel behaviors that has enabled the plant to achieve better results with fewer resources.

4. *Capital*

We have also completed a long-term re-analysis of our capital budgets for both Prairie Island and Monticello, and we have made significant changes to our capital forecast relative to our 2015 resource plan. In our 2015 resource plan, we stated that our projected capital spend for Prairie Island was outpacing the estimates included in our 2012 Changed Circumstances filing. We specifically noted that our five-year capital expenditure forecast from 2016 through 2020 had increased by roughly $175 million above what was anticipated in 2012, and that our forecast for the 13-year period from 2021 through 2034 would likely need to increase by roughly $600 to $900 million. At

[3] These reductions in our nuclear production costs are directionally consistent with the nuclear industry as a whole, which has achieved a more modest average reduction of approximately $5/MWh since 2012.

the same time, we noted that our O&M costs were lower than previously modeled and that those decreases in O&M offset the increases in forecasted capital spend.

Today, we are in a position to materially reduce our capital forecasts. To date, we have spent $77 million less at Prairie Island than we anticipated in 2015. And relative to that 2015 Resource Plan budget, we now forecast spending approximately $475 million less in capital at our nuclear plants from 2019 through their current licenses relative to our 2015 forecast (approximately $245 million less at Prairie Island and about $230 million less at Monticello during this period, excluding incremental spend required for the ten-year extension).

The updates to our forecast reflect several years of work by numerous Company employees, leadership, and external consultants, as well as a recognition that we had to re-envision our approach to nuclear operations if our plants were going to remain competitive. The forecasts are based on a detailed, long-range capital budgeting process that was undertaken following our last Resource Plan. As part of this process, teams from nuclear engineering and capital projects assessed the condition of our plants and developed a long-range project forecast to support continued operations and aging management. These teams then worked with nuclear finance to develop budgets to support project needs, and probabilities were assigned to the various projects reflecting the likelihood each would be necessary to maintain the reliability of our plants. We then worked with independent consultants with expertise in nuclear operations to assess both our budgeting process and the overall level of our capital budgets, in order to ensure that our forecast were reasonable and aligned with industry norms.

We recognize that our stakeholders and the Commission will continue to monitor our performance and investments relative to our forecasts, and we anticipate an in-depth discussion regarding our Monticello forecasts in the context of a future certificate of need filing for additional dry cask storage. We anticipate filing that petition in the mid-2020s, at which point we will have an even longer track record of performance both in terms of capacity factors and spend. We look forward to demonstrating that our nuclear plants can continue to drive both environmental performance and benefits for our customers.

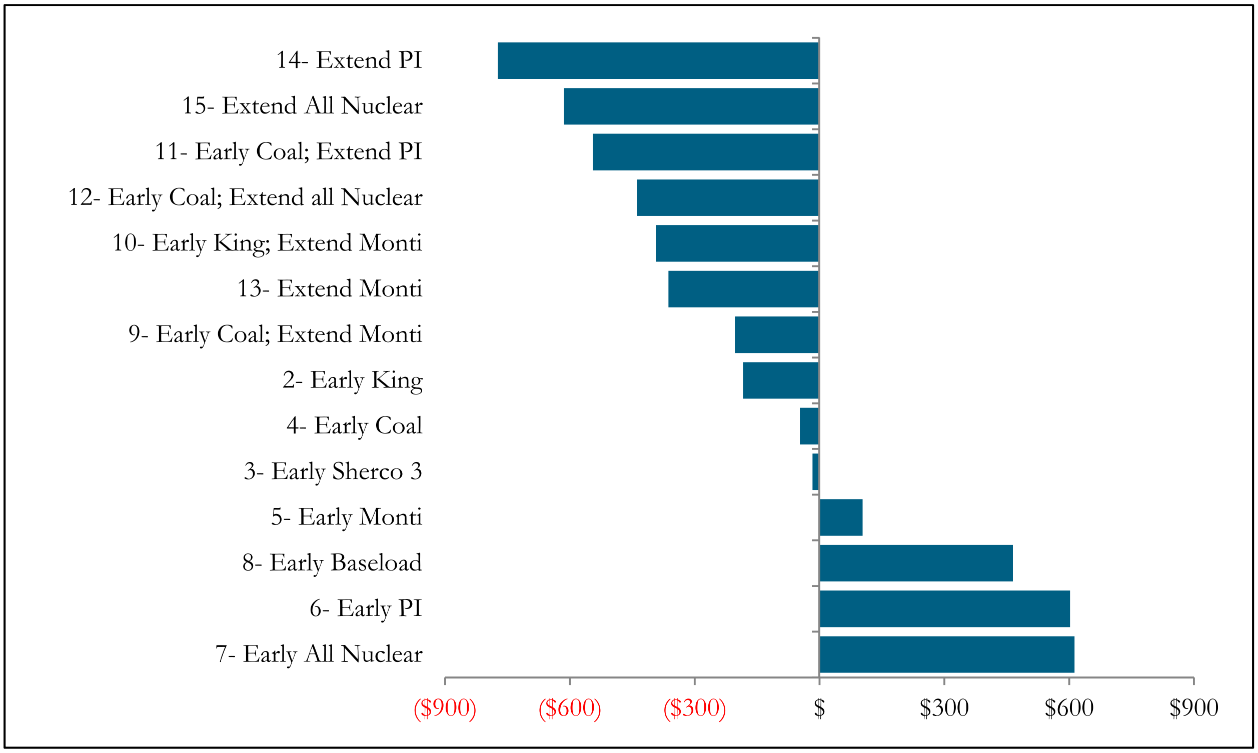
D. Benefits of Relicensing

Our Preferred Plan includes the operation of Prairie Island through its current licenses (expiring in 2033 and 2034) and a ten-year extension on the operation of Monticello (through 2040). The Strategist modeling of our plan demonstrates both that the continued operation of Prairie Island and the extension of Monticello are cost effective and expected to result in customer benefits. We discussed our Economic Modeling Framework in Chapter 5 but we briefly summarize the nuclear-specific results below.

As part of our economic analysis, we modeled scenarios that included early retirements, license extensions, and continued operation through current licenses for all three of our nuclear units. For the early retirement scenarios, we assumed a 2026 retirement date for Monticello and 2025-2026 retirement dates for Prairie Island Units 1 and 2, respectively. For license extensions, we limited our analysis to ten additional years of operations. While the NRC grants license extensions in 20-year increments, we believe it is prudent to limit our analysis to 10 additional years at this juncture, given the uncertainty of projecting more than 30 years into the future from both a budgeting and resource-planning perspective. Thus, the license extension dates are 2040 for Monticello, 2043 for Prairie Island Unit 1, and 2044 for Prairie Island Unit 2. We then combined these various scenarios with consideration of early coal retirements in order to develop a Preferred Plan.

In general, our analysis shows that extending operation of our nuclear plants is beneficial and least-cost when compared to other scenarios. The following table summarizes the Strategist results for each of the modeled scenarios:

**Figure 1: Scenario PVRR Deltas from Reference Case
($2019 millions)**



To be clear, our Preferred Plan is not the least cost scenario of the 15 options considered in terms of either PVSC or PVRR savings. The least-cost scenarios all include an extension of Prairie Island in addition to Monticello. But we believe the later retirement dates for Prairie Island—which are outside the planning period of the Resource Plan—give us additional time to consider this option before pursuing a license extension at Prairie Island.

Nevertheless, our Strategist modeling demonstrates that the extension of Monticello for an additional ten years is least cost and in our customers' interest. It also demonstrates that the continued operation of Prairie Island is superior to any of the early retirement scenarios. We believe these results provide strong support for our Preferred Plan and demonstrate the importance of our nuclear fleet from an overall resource planning perspective.

In addition to the economic benefits identified by Strategist, we believe it is also important to note the state, community, and employment benefits associated with our nuclear fleet. Our plants employ approximately 1,400 staff in and around the Monticello and Red Wing communities, which translates into an estimated 4,200 additional jobs in other industries across Minnesota. The plants are also an important sources of tax base for their host communities, resulting in a combined total of approximately $42 million in state and local taxes annually. In total, Xcel Energy's nuclear operations contribute approximately $1 billion in annual economic benefits throughout the state. These and other benefits area summarized in NEI's April 2017 report titled "The Impact of Xcel Energy's Fleet on the Minnesota Economy," which looked at data from 2014-2016[4] and is included as Appendix O3.

In short, we believe our nuclear plants provide wide-ranging and substantial benefits not only to our customers but also the environment, the State of Minnesota, and the communities we serve. The continued operation of these plants, including a ten-year extension of operations at Monticello, is in the public interest, is consistent with state policy, and is necessary to achieve our carbon reduction goals at a reasonable cost.

E. Relicensing & Certificate of Need

Although 2030 is more than a decade away, the NRC relicensing process is a long-term project that must be commenced during the five-year action plan of this Resource Plan. In this section, we discuss the NRC process of relicensing Monticello for an additional 20 years, as well as the Certificate of Need filing we will make for additional dry fuel storage.

The Atomic Energy Act authorizes the NRC to issue licenses for commercial power reactors to operate for up to 40 years.[5] These licenses can then be renewed for additional 20-year periods of "extended operation" under the NRC's License renewal rule (10CFR Part 54). Both Monticello and Prairie Island successfully received NRC approval for initial license extensions and are currently operating under the extended licenses. Approximately 90 percent of plants in the United States have already

[4] The 1,400 staff and $42 million in state and local taxes referenced above reflects updated information as through 2018.

5 Economic and antitrust considerations, not limitations on nuclear technology, determined the original 40-year term for reactor licenses. However, because of this selected time period, some systems, structures, and components may have been engineered on the basis of an expected 40-year service life. As such, a renewed license requires "aging management programs," to monitor and manage the effects of continued operation on these equipment and structures.

renewed their licenses once, extending their operation to 60 years. Most of these plants will soon reach the end of their 60-year term, and many are in the process of considering a subsequent license renewal (SLR), which would extend a plant's operation from 60 to 80 years.

To obtain an SLR, a plant must provide the NRC with an assessment of the technical aspects around plant ageing and demonstrate that it can continue to operate safely.[6] This includes review of system metals, welds and piping, concrete, electrical cables, and reactor pressure vessels. The renewal process also includes an evaluation of potential environmental impacts associated with an additional 20 years of operation. The NRC verifies evaluations through inspections and audits, and its review of license renewals is expected to last anywhere between 22 and 30 months.

That said, there is no requirement that the NRC complete its review within this time frame. There is, however, a five-year safe-harbor provision that allows operators to ensure that a plant's license will not expire during the NRC review process.[7] Specifically, 10CFR2.109(b) provides that the existing license for a plant will not be deemed to have expired during the SLR review process, provided that the licensee filed its application at least five years before the expiration of the current license. Additionally, we note that the NRC is currently reviewing three plants that have already submitted SLRs as part of a pilot program that is intended to pave the way for efficient processing of relicensing applications in the 2020s. We expect that the three pilot plants will receive license extensions in early 2020.

We intend to comply with the five-year safe-harbor in order to ensure that Monticello can continue operating throughout the entirety of the SLR review process. And because the five-year clock does not begin to run until an application is deemed "sufficient," we intend to submit our SLR application an additional six months early so that any completeness issues can be resolved before the five-year mark. Based on our experience with the first extensions for Prairie Island and Monticello, we further anticipate that it will take approximately three years to prepare the license renewal

[6] Each reactor's original license is based on a specific set of requirements, depending primarily on design. This set of requirements is called the plant's "licensing basis." The licensing renewal process provides continued assurance that the current licensing basis will maintain an acceptable level of safety for the period of extended operations.
[7] Once a license expires, a nuclear plant cannot return to operation, so it is important to comply with the safe harbor in order to avoid license expiration during the pendency of an SLR application.

application itself. This means we need to begin the SLR application process in mid-2021, so that we can submit the application to the NRC in mid-2024 (five-and-a-half years before the current license expiration in 2030.

We recognize that the Commission's ultimate decision as to the extension of Monticello will occur in the context of a Certificate of Need for additional dry cask storage, and we anticipate filing that petition in the mid-2020s when we are farther along in the SLR submittal preparation for the NRC review. However, because our work to prepare the SLR application will occur between 2021 and 2024, we are requesting that the Commission approve this work as part to of our proposed five-year action plan. In total, we estimate that the application renewal process will cost approximately $40-50 million, and we have accounted for this cost in our Strategist modeling. We will justify the reasonableness and prudency of these costs in a future rate case.

Meanwhile, we will continue to lead the industry in exploring used fuel strategies, including consolidated interim storage and transportation issues that may facilitate additional used fuel management options not yet available in the industry. Just two months ago, Xcel Energy hosted an NEI nuclear transportation table top exercise that simulated shipping casks across the county to an interim storage site. This first-of-its-kind exercise involved the participation of several organizations—including the NRC, state commissions, host communities, tribal governments, and other utilities—all of whom will be important partners as we work on fuel management options. Thus, while we have the expertise and facility to safely store used fuel on site at our plants into the future, we will continue to lead the industry in exploring alternative transportation and storage opportunities.

F. Conclusion

This Resource Plan filing represents the first of many steps that will be required to obtain the necessary approvals to extend the Monticello operating license. This process will involve an extended dialogue with our stakeholders and regulators, both at the NRC and our state Commissions. We look forward to engaging with our stakeholders around the role of nuclear in our energy future.

Our specific request in this Resource Plan is to approve a five-year action plan that includes the preparation of an SLR license application, so that we can proceed on a timeline that allows for the potential relicensing of Monticello until 2040. If the Commission approves this plan, we will be back in the coming years to seek a Certificate of Need for additional dry fuel storage. At that time, we would expect to have a more in-depth discussion regarding the detailed capital and O&M forecasts, as well as the impacts of continued operations on the local communities, the state, and our customers.

APPENDIX L – XCEL ENERGY RESOURCES: SHERCO CC

I. INTRODUCTION

We are moving forward with project development for a Combined Cycle (CC) gas plant at the Sherco site that will replace part of the capacity retiring at current Sherco Units 1 and 2, as discussed in our previous resource plan. The Sherco CC will give us an important firm dispatchable resource necessary to successfully reduce our Upper Midwest NSP System carbon emissions by 80 percent from 2005 levels by 2030 and transition to 100 percent carbon-free in 2050 – while ensuring reliable and affordable electric service to support our economy and communities. This transition will put us in many untested circumstances, where it will be critical to have viable system options to provide flexibility to respond. No one yet knows what that future looks like – and we are confident that it relies on technologies that are not yet developed. It is prudent and responsible, and our obligation as a public utility, to ensure we are planning and implementing viable infrastructure options that will help to drive a successful and economic transition to a stable future state.

Our previous Resource Plan stated that, in order to retire the coal-fired units, there were certain grid reliability issues that would need to be resolved, as well as community support objectives to meet. Those issues remain true today. There have also been several developments since our last Resource Plan that reinforce and highlight the system benefits the Sherco CC will provide.

Overall, building a new CC at the Sherco site is the most appropriate holistic solution to serve grid needs when the Sherco coal units retire, for the following reasons:

- It will provide system needs including voltage support, power deliverability, and system regulation in the absence of Sherco Units 1 and 2.
- It will provide replacement capacity for our black start restoration path.
- It will facilitate our carbon reduction plan in three ways. First, in providing the grid support the Monticello nuclear plant needs (and which will be absent if the Sherco Units are not replaced). Second, by facilitating the integration of large renewable additions contemplated by our Preferred Plan. Third, by avoiding the costly and lengthy transmission upgrades that would be required if we built new units on a greenfield site.
- It will satisfy, in part, the system's need for sufficient firm and dispatchable capacity as our coal units retire and do so in a way that is superior to CTs

because of the lower heat rate and emission profile.

- It will help us fulfill our commitments to the Becker community as we transition away from legacy coal-fired baseload assets.

We discuss each of these factors in more detail below, and we also provide an update as to the status of the Sherco CC project.

II. THE NEED FOR THE SHERCO CC AS DISCUSSED IN OUR LAST RESOURCE PLAN

In our last Resource Plan, we proposed to retire Sherco Units 1 and 2, which provide approximately 1,400 MW of stable, baseload generating capacity to our system. Given the amount of energy and firm capacity these two baseload units provide, we undertook an in-depth analysis to determine the grid needs that would arise upon their retirement.

The specific studies the Company undertook included an Attachment Y2 study, performed by MISO, and a separate study by Siemens Power Technologies International. The Y2 is a non-binding, informational study that identifies any reliability impacts of a potential future status change of a generating unit(s) – in this case, Sherco Units 1 and 2. The MISO Tariff requires that any generation retirement be studied and approved by MISO to ensure that it results in no adverse effects to the reliability of the system, and we commenced the Y2 study when we first contemplated retiring Sherco Units 1 and 2. The focus of this study was on the impacts to the broader MISO grid if one or both of Sherco Units 1 and 2 ceased operation.

We retained Siemens to study the effects of potential phased retirement of one or both Sherco Units on the transmission system, technical implications (including voltage analyses and transient stability analyses) and upgrade costs associated with replacement of one or both Units at alternate locations on the NSP System, and the potential impacts of the cumulative effect of additional larger generation unit retirements on the NSP System, in particular the Monticello Nuclear Plant due to its proximate location in Sherburne County and one Prairie Island Unit in combination with Sherco Units 1 and 2.

Below we briefly discuss the studies' findings and note that each of the issues identified by the retirement of the Sherco Units below is solved by the Sherco CC – holistically and at a prudent cost to our customers. For a more in-depth discussion of these reports, please see Attachment D to the Company's January 29, 2016

Supplement to its 2015 Integrated Resource Plan in Docket No. E002/RP-15-21.

A. Voltage Support

The Y2 study found that retiring the existing units (with no replacement solution) would result in significant violations of the prevailing voltage and thermal ranges. Analysis of bulk electric system (BES) impacts from new or changing generation and transmission facilities are measured against standards and requirements established and enforced by the North American Reliability Corporation (NERC), per authority from FERC.[1]

The real-time conditions on the transmission system are constantly changing and require ongoing adjustments to maintain voltages at required levels. As large synchronous power sources, Sherco Units 1 and 2 also provide system voltage support and reactive power. The system must be able to facilitate both "active" and "reactive" power. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power, measured in volt-amperes reactive (VARs), is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps and air conditioning). Due to physics, reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators. If the correct level of reactive power cannot be supplied promptly and in sufficient quantity, voltages deteriorate and, in extreme cases, can result in a voltage collapse.

The issues identified by the Y2 study were significant enough that MISO would likely designate the units as System Support Resources (SSR) and not allow them to retire as planned, if an alternate mitigation was not in place. These violations would also be in conflict with the Monticello nuclear plant's operating license. To move forward with the Sherco retirements, MISO and/or the Nuclear Regulatory Commission (NRC) would require that the Company mitigate the identified voltage and thermal violations in another manner, generally requiring either new firm generation on site or significant transmission system upgrades.

B. Power Deliverability

The Siemens' analysis confirmed that the system operates well with significant

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[1] We discuss NERC's role in more detail in Appendix J1: Baseload Study.

injection at the Sherco site and that replacing the retiring units at a different location would require transmission system upgrades and come with other tradeoffs (i.e. increased energy losses from a new unit placed further away from the Twin Cities' load center). Transmission systems are typically developed to receive significant amounts of power from specific injection sites and then move the power over long distances to meet areas of demand. This amount of power than can be moved is often referred to as "transfer capability," and changing generator characteristics or locations impacts the performance of the surrounding grid by impacting Transfer Capability.

Our system was designed to receive significant injections of power from the Sherco site and then deliver energy out from it to areas of customer demand, including the Twin Cities metro area. The Siemens study confirmed that replacement of Sherco Units 1 and 2 with a large generating unit that provides similar benefits to the NSP System as the existing Sherco Units (like a combined cycle) will cost-effectively meet the physical system requirement to ensure voltage, frequency, and reliable service for our customers.

C. System Regulation

The Siemen's analysis also addresses the heavy reliance of the system on Sherco Units 1 and 2 for system regulation. System regulation essentially refers to the ability of the system to maintain reliable operation through changes in usage and production. In other words, equipment that provides system regulation ensures that the grid is keeping generation and load in balance at all times.

To maintain this balance, there is a need for system resources that are flexible and responsive to dispatch signals. Currently, the system relies heavily upon units like Sherco Units 1 and 2 to provide this type of regulation. The overall system frequency, required to be maintained at 60 Hz in the U.S., is an active measure of this balance. When there are sudden large changes to the generation and load balance, such as a generating unit dropping offline or an event that disrupts operation of a transmission facility, the frequency of the grid can fluctuate up and down depending on the size of the disturbance. The grid requires sufficient system regulation, which means its ability to respond instantly to changes in usage – i.e., keeping the generator and loads matched at all times. Insufficient system regulation can cause disturbances like these to make the system unstable. However, the Sherco CC addresses these system regulation issues because of its electrical characteristics that provide this fast response balancing in real time, similar to Sherco Units 1 and 2 today.

D. Black Start

In addition to the needs identified by the studies discussed above, Sherco Units 1 and 2 also play a critical role in our system when it comes to black start planning. In the event of a major outage, the existing Sherco Units 1 and 2 units are an integral "Target Unit" in our grid restoration plan. Once an "Initial Unit" (i.e. the unit that jumpstarts the grid) is re-started, Sherco Units 1 and 2 can be started and run at low loads and provide the necessary capabilities to restart other key generators, such as Sherco Unit 3, in the restoration path.

Only dispatchable units of a certain size that are capable of creating and absorbing reactive power are eligible to provide this function, and there are few viable alternatives in our current system. Nuclear units, for example, can only come online after the system is fully stable, and thus are not used as Target Units. Renewable generation, such as solar and wind, are generally not able to provide these services effectively, nor for the duration needed to serve as the Target Unit, due to their inability to create and absorb sufficient levels of reactive power – and because they are weather-dependent and not firm and dispatchable. A large battery energy storage system can technically be configured to be capable of providing black start service, likely as part of a relatively small initial black start unit. However, current battery technologies may not yet be economically viable for this purpose. There are also technical concerns with regard to how batteries can absorb reactive power, which would be needed if the battery was not paired with another type of generation asset.

While the Blackstart Plan can be re-routed if needed, constructing the proposed CC at Sherco provides the most efficient restoration path, and avoids other upgrades that would be required to re-route the path. As we noted in our January 29, 2016 Resource Plan Supplement in Docket No. E002/RP-15-21, altering the path away from the Sherco site would require various equipment upgrades on our transmission system and potentially the addition of new generation elsewhere if transmission upgrades could not fully mitigate this need. Selecting a less efficient path would also lengthen the overall restoration period, which may result in other restoration challenges during cold weather events.

III. EMERGENT ISSUES IN THIS RESOURCE PLAN

Since the last Resource Plan, the system conditions discussed above and underlying our need for a new CC at Sherco have not changed in any material way. In fact, we see many of the reliability issues identified becoming more relevant and pronounced in light of our aggressive carbon goals and the transmission interconnection constraints that have emerged in recent years. Below, we discuss the issues new to this Resource Plan, which we believe further confirm the need for the Sherco CC.

A. Monticello Extension

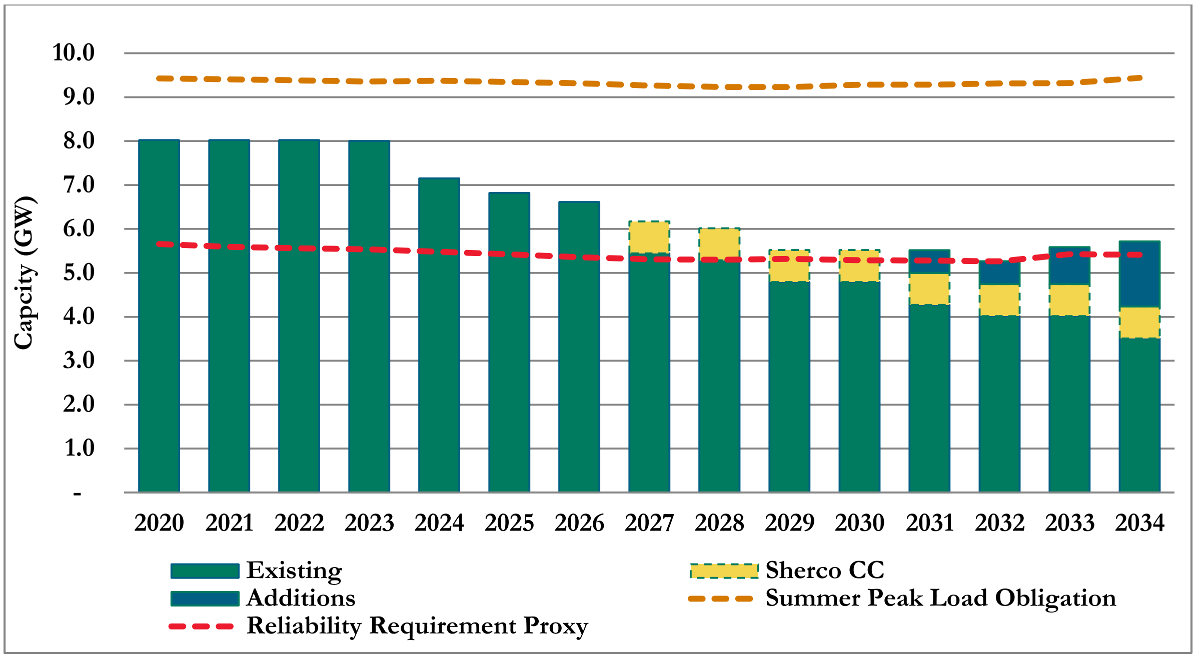
Extending the Monticello nuclear plant's operational life for 10 years past its current retirement date helps us retain zero emissions baseload power on the system while we integrate additional intermittent renewables (in particular, solar PV) in 2025 and beyond. However, as discussed in our last Resource Plan, we need a large grid-stabilizing resource to ensure we can operate Monticello within the requirements of our NRC operating license. And the transmission issues outlined in our previous Resource Plan filing have also not improved. In fact, the MISO generator interconnection queue is more congested now than it was in 2016, with substantial new renewable generation proposed but very little additional transmission capacity dedicated to integrating those resources. This would very likely impact our ability to site necessary stabilizing resources in a greenfield location near Monticello, and any new unit would likely be responsible for substantial transmission upgrade costs to interconnect to the broader grid—assuming it could even make it through the MISO queue in time to facilitate a 2026 retirement of Sherco Unit 1.

B. Reliability Requirement

Not only is the Sherco CC beneficial in supporting the proposed Monticello extension, it also helps ensure that we have sufficient load supporting, firm dispatchable resources on our system for grid resilience and reliability purposes. As we increase the amount of renewable generation on our system, these resources alone cannot reliably provide customers the energy they demand every hour of every day – or maintain the stability of the grid. Until MISO planning constructs fully incorporate measures to address the emerging challenges associated with increasing levels of renewables, we have incorporated a Reliability Requirement into our planning for this Resource Plan (See Appendix J2). Our Preferred Plan does not show a need for additional load supporting resources until 2031, which is partially so because the Sherco CC is already modeled as a part of our future resource portfolio.

As seen in Figure 1 below, if we were to forego building the Sherco CC, we would begin to see a firm capacity deficit relative to the Reliability Requirement by 2029, with the gap widening post-2030 when Sherco Unit 3 retires. Given technologies available today, this need would be most cost-effectively be filled by gas combustion turbines (CT). However, CTs also typically run at higher heat rates, with higher levels of emissions than CCs. While we have said we can wait until future cycles to reevaluate and determine which technologies may be able to meet these needs in the post-2030 timeframe, we have a responsibility to ensure we meet our customers' needs now. The confluence of Monticello and grid stability needs, and proposed coal retirements further support that the Sherco CC is an appropriate choice to provide that system reliability service in the near term.

Figure 1: Projected Firm Capacity as Compared To Summer Peak and Reliability Requirement[2]



We are facing a long transition from today to 2030 – and even longer to 2050 – with significant changes at multiple stages. We must have operation options that give us flexibility to respond to many unknowns that are sure to come. The Sherco CC will help us make this transition responsibly, while we monitor developments and take advantage of technologies, such as hydrogen and other carbon-free fuels when they become commercially-viable. We discuss some of these resources in Appendix F6: Resource Options.

C. Renewable Integration Support

As we begin to integrate even higher levels of variable renewables on our grid, the

[2] Note that our Preferred Plan modeling also includes MEC's full capacity throughout the planning period, which may result in an additional gap if the proposed acquisition is not approved. The firm supply depicted here also includes DR additions per the Preferred Plan.

value of a dispatchable intermediate resource like the Sherco CC increases. Our Preferred Plan includes 4,000 MW of new renewable development, some of which would be added as early as 2025. Adding substantial new variable renewable resources requires us to maintain a subset of resources that can provide both fast ramping capabilities and the longer duration energy needs, for times when these variable renewables are not available. Moreover, these renewable additions will occur during the same period in which we are retiring over 2,400 MWs of coal-fired generation (1,360 MW of previously planned coal retirements from Sherco Units 1 and 2, and another 1,045 MW of retirements by 2030 proposed at Sherco Unit 3 and King. As we replace increasing amounts of existing coal generation with cleaner fuels, the Sherco CC will support our transition by allowing us to reduce and ultimately eliminate dependence on coal units for these balancing and integration needs going forward.

Additionally, as the MISO region realizes substantially higher levels of renewables, planning constructs need to change from today's single system peak capacity construct – and adapt to the diminishing marginal returns these variable resources can provide. MISO has itself acknowledged in its *Renewable Integration Impact Assessment* (RIIA) study that, at higher levels of renewable adoption on the grid, the ELCC of wind and solar resources will decline.[3] The firm capacity the Sherco CC will provide will become even more valuable in meeting our customers' needs every hour of every day as we navigate this transition while maintaining reliability.

D. Community Impact

Aside from significant grid support benefits discussed above, the Sherco CC also will partially offset the community tax and employment losses in Becker and Sherburne County that will result from the early retirement of the existing Sherco Units (including our proposal in this Resource Plan to retire Sherco Unit 3 in 2030). It also provides options for continued industrial steam supply to the Liberty Paper recycling facility located nearby. In addition, the Sherco CC could also provide options for our Sherco Unit 3 partner, Southern Minnesota Municipal Power Agency (SMMPA). These host communities and partners have been an integral part of our system for nearly 45 years, and we are committed to partnering with them as part of our upcoming baseload transition in hopes of mitigating the impacts of our Sherco retirements. Building a new CC unit at Sherco offers us the opportunity to meet our grid needs and serve the public interest, while also mitigating the impacts to these host communities and partners.

[3] *See* Chapter 2: Planning Landscape and Appendix J1: Baseload Study for more detail.

IV. ALTERNATIVE OPTIONS

While it is possible to meet some of the identified grid needs with alternate investments, the Sherco CC provides a path to meet all of these needs holistically and at a prudent cost to our customers. Below we discuss the three alternatives we evaluated: (1) a Synchronous Condenser (SC), (2) renewables-plus-storage, and (3) alternative greenfield CC solutions. We discuss each of these alternative options briefly below and will expand this discussion in detail in our upcoming Sherco CC regulatory filing.

A. Synchronous Condenser

With respect to voltage support, one potential alternative solution would be the conversion of one existing generating unit into a Synchronous Condenser (SC). A SC is a motor, whose shaft is not connected to anything but spins freely. Its purpose is not to produce electric power, but to adjust conditions on the electric power transmission grid. Our initial analysis indicated that a SC may provide the required continuous voltage support the Monticello plant requires as well as the requisite inertia (due to its large rotating mass) to meet the grid's stability needs. However, a SC would not be able to address the thermal support Monticello requires or the black start capabilities the system requires.

In addition, our Preferred Plan proposes to retire Sherco Unit 3 in 2030. This has two key implications for the viability of a SC as an alternate investment to the planned Sherco CC. First, our Preferred Plan includes a proposal to pursue a Monticello nuclear operating license extension that would allow us to operate that plant through 2040. Both the Monticello license extension and our proposal to retire Sherco Unit 3 in 2030 are fundamental components of our carbon reduction goals. The SC design we studied, however, would not be able to provide the grid services we need to remain compliant with our nuclear operating license after Sherco Unit 3 retires. Indeed, it is not clear that the NRC would approve a relicense with only SC support, as opposed to a generating facility. And even if it were approved with only SC support, the SC would need to be much larger than previously anticipated in order to provide similar grid stability benefits after all the 2,400 MW of existing Sherco generation retire. Further, a SC provides reactive power by consuming power. Because of this, a SC does not address the need for firm dispatchable resources to meet our customer's capacity and energy needs. In this way, the Sherco CC provides a much greater value to the overall system.

Second, the three existing Sherco Units are key components of our current Black Start Plan, and a SC on its own cannot replace this functionality. We noted in our last Resource Plan that our Black Start Plan is substantially dependent on capacity at Sherco Units 1 and 2 being Target Units, and providing sufficient output to support restarting Sherco Unit 3 and then the remainder of the NSP system. Retiring Sherco Units 1 and 2 would require re-designing our restoration path and potentially substantial associated transmission upgrades, if not replaced with another type of firm and dispatchable generation. The Sherco CC helps us to bridge that gap after Sherco Unit 1 retires in 2026. Now that we are also planning to retire Sherco Unit 3, the Sherco CC becomes even more essential in maintaining our black start capabilities. Because the SC does not generate real power, it cannot provide the Black Start functionality that we need for our system.

B. Renewables Plus Storage

Given the Company's clean energy goals, we also considered whether or not a paired renewables-plus-storage facility could provide a viable alternative solution to the Sherco CC. While the renewable plus storage might provide adequate capacity and energy, a SC may also be needed to meet the grid reactive power voltage support needs discussed earlier. We anticipate storage being a key part of our system in the longer term, however, such a solution is not currently cost-effective at the scale required for this application – and would be much more complex to implement and operate. It is also not clear whether the NRC would allow a storage facility to serve as the external support required by our nuclear operating license for Monticello. Even assuming it was approved, though, the external support unit is required to be available for a duration exceeding the longest potential outage that Monticello could encounter. In normal operational conditions, outages for refueling at the plant could be expected to last approximately 30 days. This duration is far longer than currently available storage solutions could be reasonably expected to provide support, much less provide it at a reasonable cost. Even a solution that could, for example, provide continuous grid support of this magnitude for a single 24-hour period would be exorbitantly expensive.

In this example, such a plant would require a battery configuration that could provide hundreds of MW of full discharge capabilities for multiple cycles. And while we expect the cost and capabilities of battery technology to improve over the planning period, it is highly unlikely they would improve sufficiently to make this a more cost effective solution than the Sherco CC. The Sherco CC will be able to provide continuous support to the broader grid and Monticello across many consecutive days – indeed months - without needing to pull significant energy from another on-site generator, or the broader grid. Today's short-term energy storage solutions simply cannot provide this level or kind of support. Future technologies may make this type of solution much more viable and economic. However, with grid stability and reliability at stake, we do not see a renewables-plus-storage solution as a viable alternative to the Sherco CC at this time.

C. Alternative Greenfield CC

As discussed in more detail in Appendix I: Supporting Infrastructure-Transmission and Distribution, the existing transmission system's capability to interconnect new projects without substantial infrastructure upgrades is very limited, and thus, the generation interconnection planning studies indicate there will likely be costly upgrades assigned to the prospective generators. The value of our Sherco interconnection is incredibly valuable due to the potential for upgrade costs assigned to greenfield projects as well as the time component associated with the interconnection process.

In 2018, we asked an independent engineering consultant to help us evaluate the cost and feasibility of building a greenfield CC plant. Six potential sites were examined. Overall, the study led us to the conclusion that building a greenfield CC would not be an economically favorable alternative, nor would a plant likely be able to be placed in-service in the timeframe we needed. As greenfield sites, we would have to gain new interconnection rights and conduct transmission system upgrades that would present significant challenges not only to building a cost competitive solution to the Sherco CC, but also to achieving the 2026 in-service date we need to transition Sherco Unit 1 off the system. The study determined that, across these six potential locations, the average required transmission system upgrade costs for a selected site would amount to more than $500 million.

To put the plant in service by the time Sherco Unit 1 retires, the study determined we would need to see a 60 percent withdrawal rate from the MISO interconnection queue as it existed at the time of evaluation.[4] In our experience, it would be unrealistic to expect transmission upgrades, and any necessary transmission and plant permitting and interconnection processes, to be completed in an appropriate timeframe for a greenfield site option to be viable. Thus, this was determined to not be a favorable alternative to the Sherco CC.

[4] The Interconnection Cost Estimate Study performed by Excel Engineering is provided in this filing as Appendix R.

V. CURRENT STATUS

The Company is currently in the project development stage with regard to moving forward on the Sherco CC. We expect this plant to utilize the best available technology for the design specifications at the time of construction, based on technology information from the major equipment suppliers in the market. When it is built and put into service, we also expect the plant to be the most efficient gas generator, with the lowest carbon emission rates, in our generation fleet and that it will be competitive in the MISO Upper Midwest market as well.

The project specifications are based on a 2x1, wet-cooled, unfired design condition. We have used internal estimates and currently available technology information to include the plant, and estimated associated new infrastructure required, in the Strategist-modeled portfolios presented in this Resource Plan. However, these cost estimates are preliminary and subject to updates as we progress through the project development process. In preparation to move forward with the project, we are currently working with consultant engineering firms to develop more targeted and up-to-date cost estimates for the new generation facility and required firm natural gas supply infrastructure, and to better define expected project schedules. We expect these inputs to inform our project development plans moving forward, as we thoroughly evaluate equipment and infrastructure supply options and make any relevant filings to the Commission.

We also note that there are several steps we are preparing to complete with regard to generator interconnection rights for the Sherco CC, and this process will also affect how the Sherco CC development process moves forward. We expect we will need to file a MISO Attachment X generator interconnection request in order for the CC to utilize the same interconnection rights currently assigned to the Sherco coal units. This must be filed at least one year prior to the existing unit ceasing operation, and the new unit must go into service not more than three years after the existing unit(s) cease to operate. We plan to meet these requirements so that we can avoid the lengthy interconnection queue process.

When we file these details with MISO, that initiates any reliability studies required under the MISO Tariff – the results of which MISO will share within 180 days of the request.[5] The Tariff currently provides that these studies will evaluate whether the

[5] The Attachment X Tariff provides that the Transmission Owner [MISO] shall use Reasonable Efforts to complete the Replacement Impact Study and Reliability Assessment Study and share results with the Interconnection Customer within one hundred eighty (180) Calendar Days of the request.

replacement generating facility has a material adverse impact on the transmission system when compared to the existing generating facility and the performance of the transmission system, and to determine if thermal and/or voltage violations of applicable NERC standards and MISO planning criteria are caused by removing the existing generating facility from service prior to the commercial operation date of the replacement generating facility. Upon completion of these studies, Xcel Energy Transmission will subsequently study any required facilities upgrades or changes – and MISO will incorporate these into the new Generator Interconnection Agreement we receive for the Sherco CC.[6]

VI. CONCLUSION

The need to build new firm capacity at the Sherco site has not abated since our last resource planning cycle. The Sherco CC is an important bridge to the future. No one yet knows what that future looks like – and we are confident that it relies on technologies that are not yet developed. The Sherco CC will give us the necessary flexibility that help us through all the different transitional stages to come, without risking grid resilience and customer reliability. Without the Sherco CC, we will be challenged to maintain the clean baseload power provided by our Monticello unit into the future, and challenged to integrate the thousands of megawatts of new solar power proposed in our Preferred Plan, while retiring the last of our coal units.

For these reasons, we included the Sherco CC as a baseline resource in our Preferred Plan and in the additional scenarios we analyzed. We are moving forward with project development internally, including working with engineering consultants to develop more detailed estimates for the cost to build the CC and secure the associated firm gas supply for the site. These estimates will be used to help ensure the project is completed at a reasonable cost to our customers. We plan to bring forward a detailed filing to the Commission in the coming years, which will present the most up-to-date information for this project.[7]

[6] The evaluation currently consists of two studies: i) a Replacement Impact Study as set forth in Section 3.7.2.1 of the GIP, and ii) a Reliability Assessment Study as set forth in Section 3.7.2.2 of the GIP.
[7] As authorized by HF 113, filed February 28, 2017.