Xcel Energy Demand Response Offerings

2017-2019 Stakeholder Engagement Process Summary Report

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

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

About this Report

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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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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.

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[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 <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."[7]

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[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

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[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

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[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.