414 Nicollet Mall
Minneapolis, Minnesota 55401-1993

April 30, 2021

—Via Electronic Filing—

Will Seuffert
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101

Re: 2020 ANNUAL REPORT
PERFORMANCE METRICS AND INCENTIVES
DOCKET NO. E002/CI-17-401

Dear Mr. Seuffert:

Northern States Power Company, doing business as Xcel Energy, submits the enclosed Performance Metrics Annual Report for the period of January 1, 2020 to December 31, 2020 pursuant to the Minnesota Public Utilities Commission's April 16, 2020 ORDER ESTABLISHING METHODOLOGIES AND REPORTING SCHEDULES in the above-noted docket.

We have electronically filed this document with the Commission, and copies have been served on the parties on the attached service list. Please contact Bridget Dockter at bridget.dockter@xcelenergy.com or (612) 337-2096 or Mary Martinka at mary.a.martinka@xcelenergy.com or (612) 330-6737 if there are any questions regarding this submission.

Sincerely,

/s/

ALLEN D. KRUG
ASSOCIATE VICE PRESIDENT, STATE REGULATORY POLICY

Enclosures
c: Service List

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie J. Sieben	Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
Joseph K. Sullivan	Commissioner
John A. Tuma	Commissioner

IN THE MATTER OF THE COMMISSION INVESTIGATION TO IDENTIFY AND DEVELOP PERFORMANCE METRICS AND POTENTIALLY, INCENTIVES FOR XCEL ENERGY'S ELECTRIC UTILITY OPERATIONS

DOCKET NO. E002/CI-17-401

ANNUAL REPORT

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy, submits this Performance Metrics Annual Report (Report) for the period of January 1, 2020 to December 31, 2020 pursuant to the Minnesota Public Utilities Commission's April 16, 2020 ORDER ESTABLISHING METHODOLOGIES AND REPORTING SCHEDULES in the above-referenced docket. We provide an evaluation of results on the 28 Commission-approved metrics tracked for calendar year 2020, offer updates on new metrics that we are continuing to develop, and report on required stakeholder engagement.

Xcel Energy is the first and only Minnesota utility operating under a multiyear rate plan pursuant to Minn. Stat. § 216B.16, subd. 19, which authorizes, in part, the Commission to require a "utility to provide a set of reasonable performance measures and incentives that are quantifiable, verifiable, and consistent with state energy policies." Pursuant to this authorization, the Commission initiated the present proceeding to gain a better understanding of how performance metrics and standards, and potentially incentives, in addition to those already in Xcel Energy's Quality Service Tariff[1] could further align the Company's strategic priorities with the public interest.

During a robust and engaging stakeholder process, participating stakeholders considered calculations, verification, reporting, process schedules and progress updates, and agreed to revisit and re-assess any approved metrics later in the proceeding as needed. The

[1] Xcel Energy Minnesota Electric Rate Book – MPUC No. 2, Section 6, Sheets 7.1 to 7.11.

Commission ultimately adopted 28 metrics related to customer focus, utility performance and public policy.[2]

The Commission recommended data gathering begin on January 1, 2020 for approved metrics. To provide the Commission with an update, we proposed filing an annual report of available metrics data for the time period January 1, 2020 through December 31, 2020 on April 30, 2021, with similar filing timelines in subsequent years. As stated in our December 12, 2019 *Reply Comments* in this docket, we recommend tracking and reporting on the initial metrics ordered by the Commission for a period of three years to determine if those metrics are useful and if they continue to remain valid in the future. In addition, we recommend revisiting the metrics in this docket after three years of reporting to ensure the Company is addressing the correct metrics.

We are pleased to provide this assessment of the Company's performance metrics tracking for 2020. This report is organized as follows:

- Section I lists the Commission-approved metrics and reporting requirements;
- Section II discusses specific April 16, 2020 order points that require additional explanation beyond the information included in our spreadsheet;
- Section III summarizes stakeholder discussions and associated filing requirements; and
- Section IV addresses Commission-ordered follow-up and offers a reporting proposal.

2020 PERFORMANCE METRICS

I. ESTABLISHED OUTCOMES AND METRICS

The grid below lists the 28 metrics approved by the Commission on April 16, 2020, by Outcome, provides reference to the corresponding line in Attachment A, and notes any attachments specific to that metric. Most metrics are reported in Attachment A, unless they required additional discussion.

[2] *In the Matter of a Commission Investigation to Identify Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operation*, Docket No. E002/CI-17-401, ORDER ESTABLISHING PERFORMANCE METRICS at 12-14 (September 18, 2019).

A. Approved Metrics

Outcome / Metric	Corresponding Row in Attachment A	Reporting Status	Associated Report Attachment
Affordability			
Rates per kWh based on total revenue, reported: (1) by customer class and (2) with all classes aggregated	1	New	n/a
Average monthly bills for residential customers	2	New	n/a
Total disconnections for nonpayment for residential customers	3	Current	n/a
Total arrearages for residential customers	4	Current	n/a
Reliability			
System Average Interruption Duration Index (SAIDI)	1	Current	n/a
System Average Interruption Frequency Index (SAIFI)	2	Current	n/a
Customer Average Interruption Duration Index (CAIDI)	3	Current	n/a
Customers Experiencing Long Interruption Duration (CELID)	4	Current	n/a
Customers Experiencing Multiple Interruptions (CEMI)	5	Current	n/a
Average Service Availability Index (ASAI)	6	Current	n/a
Momentary Average Interruption Frequency Index (MAIFI)	7	Current, but not with AMI technology Report in 2026	n/a
Power Quality	8	New Report in 2026	n/a
Customer Service Quality			
Existing multi-sector metrics, including ACSI and J.D. Power (MN)	1	New	B
Call center response time	2	Current	n/a
Billing invoice accuracy	3	Current	n/a
Number of customer complaints	4	Current	n/a
Environmental Performance			
Total carbon emissions by (1) utility-owned facilities and PPAs and (2) all sources	1	New	n/a
Carbon intensity (emissions per MWh) by (1) utility-owned facilities and PPAs and (2) all sources	2	New	n/a
Total criteria pollutant emissions	3	New	n/a
Criteria pollutant emission intensity (criteria pollutant emissions per MWh)	4	New	n/a
CO_2 emissions avoided by electrification of transportation – Alternative & Original approach		New	n/a
a. Percent of Electric vehicles in Xcel Energy's Minnesota service territory participating in managed charging programs or on whole house rates	5(a)		
b. Percent of managed charging customers residential electric vehicle charging load occurring during off-peak hours	5(b)		
c. CO_2 avoidance calculated from electric vehicle charging	5(c)		

Outcome / Metric	Corresponding Row in Attachment A	Reporting Status	Associated Report Attachment
CO2 emissions avoided by electrification of buildings, agriculture, and other sectors	6	New	n/a
Discussion of fugitive emissions of methane, including proposed methodology for reporting fugitive emissions for methane	7	New	n/a
Cost Effective Alignment of Generation and Load			
Demand response, including (1) capacity available (MWh) and (2) amount called (MW, MWh per year)	1	Current	n/a
Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns.	2	New/TBD	n/a
Amount of demand response that SHIFTS energy consumptions from times of high demand to times when there is a surplus of renewable generation.	3	New/TBD	n/a
Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events a. For available load b. For actual load reduction c. Metrics that measure the effectiveness and success of (a & b) individually and in aggregate	 4(a) 4(b) 4(c)	New	n/a
Workforce and Community Development			
Workforce and Community Development Impact	1	New/TBD	H, I, J
Other Stakeholder Discussions			
Public Dashboard	1	New/TBD	F, G
Demand Response Performance Incentive	2	New/TBD	C, D, E
Evaluation Criteria and Benchmarks	3	New/TBD	n/a

B. Future Metrics

The Reliability Outcome metrics of $MAIFI_E$ and Power Quality are both considered future metrics, as they are tied to the successful deployment of our proposed Advanced Meter Infrastructure (AMI). We currently anticipate AMI deployment will be complete by the end of 2024. As a result, tracking will begin in 2025 and reporting will begin in 2026. It should be noted that while the Company does currently report on $MAIFI_E$, until AMI is fully deployed, the $MAIFI_E$ numbers will continue to reflect only the momentary data as reported via Supervisory Control and Data Acquisition (SCADA) systems.

1. $MAIFI_E$

To provide clarification, MAIFI, which stands for Momentary Average Interruption Event Frequency Index, has been used interchangeably with $MAIFI_E$ or Momentary Average Interruption Frequency Index Event. $MAIFI_E$ counts all momentary interruptions occurring within a five-minute timeframe as one momentary interruption event, while MAIFI counts each individual interruption less than five minutes in length. The customer impact is best represented by $MAIFI_E$, because the effect on the customer (*e.g.,* equipment stopping, or clocks needing to be reset) is as likely to occur with a single momentary interruption as it is with two or three momentary interruptions.

With the implementation of AMI, we can more accurately capture the customer momentary interruption experience. However, although the capture of momentary interruptions will be greatly improved, technology limitations may result in under- or over-reporting. Specifically, every interruption the customer experiences may not be captured, and certain interruptions may be captured although they are not technically considered an interruption. Interruptions less than one second often will not be recorded as an interruption, while voltage sags may show up as a momentary event even though no protective device has operated. As we gain experience with capturing momentary interruptions, analysis and reporting will need to be developed to ensure under or over reporting concerns are minimized.

Today, a momentary interruption is captured only when a device at a substation operates and is recorded through our SCADA system and entered into our Outage Management System (OMS) system. In the future, we will be able to capture momentary interruptions that will include: devices that operate at a substation without SCADA; operation of reclosers on the distribution line; change-out of meters; and line maintenance work that requires customer outages less than five minutes.

2. Power Quality

Once AMI is implemented, power quality could be tracked and a percent of customer exceptions can be reported. Specific capabilities are still under development and will be determined in the coming years. At this time, we envision remote monitoring and power quality verification with the implementation of AMI, with an initial focus on the monitoring of voltage level issues. We look forward to determining the full capabilities and value AMI brings to monitoring power quality and reporting the benefits to our customers.

C. Equity Metrics Moved to Service Quality Docket

In its April 16, 2020 Order, the Commission moved the three equity-based metrics into our annual service quality report filing (Docket No. E002/M-20-406[3]); therefore, they are not included here. These metrics include two reliability outcome metrics:

[3] See Xcel Energy's August 17, 2020 Comments.

1) locational reliability, and 2) reliability by geography, income, or other relevant benchmarks. These metrics map SAIFI by zip code, and overlay with census income, to provide a balanced view of overhead and underground reliability. The third equity metric is customer service quality by geography, income or other relevant benchmarks. This metric will overlay census income data with geographic data to provide the number of customer complaints as reported in the service quality tariff.

II. RESPONSE TO COMMISSION ORDER POINTS

The nature of the metrics and their calculations approved in the Commission's Order require both a final calculation as well as a more fulsome explanation for certain metrics; this section provides that explanation. For easy cross-reference, those metrics where we provide additional narrative below are noted in the metrics list, Attachment A.

A. Customer Service Quality

1. J.D. Power

The J.D. Power calculation of overall satisfaction score is a weighted index based on customer scores across 36 different attributes that fall into six broad categories:

(1) power quality & reliability;
(2) billing and payment;
(3) corporate citizenship;
(4) communications;
(5) price; and
(6) customer service.

The weighting for each category ranges from 5% to 28%, totaling 100%. The 36 attributes provide additional opportunities to improve satisfaction beyond the six categories. Examples of the 36 attributes include: customer communications during an outage; ease of understanding and fairness of pricing; ease and variety of options to pay bills; taking action to care for the environment; helping customers understand how to reduce energy use; communicating safety around electricity; and ease of using our call center and website for customer service. J.D. Power data scientists use proprietary regression modeling to refine this weighting annually to maintain a current picture of what drives customer satisfaction with utilities.

J.D. Power publishes utility satisfaction scores by region for residential customers each year in December (starting 2020) at the end of its annual study and makes the scores available to the public. J.D. Power combines customer scores for Xcel Energy customers in Minnesota, North Dakota, South Dakota, Wisconsin, and Michigan and publishes the score in *Xcel Energy Midwest*. J.D. Power does not report scores publicly at a more granular level.

Xcel Energy confirmed with J.D. Power that Xcel Energy's scores for the state of Minnesota could be shared annually with the Commission and used in a public facing online dashboard.

Table 1 below sets forth the Minnesota residential overall satisfaction scores for 2020, and for reference 2019 and 2018. Table 1 also includes the scores of the top six categories surveyed by J.D. Power. Our peer set, as defined by J.D. Power, includes 55 investor-owned utilities (IOUs) who also participate in the survey. As shown below, Xcel Energy ranked at 69% for overall customer satisfaction in 2020.

Table 1
Minnesota Residential Overall Satisfaction Scores for 2018-2020

Xcel Energy - MN Residential OSAT Index + Major Factors	2020 Peer Set Percentile Rank	2019 Peer Set Percentile Rank	2018 Peer Set Percentile Rank
OSAT*	69%	89%	78%
Power Quality & Reliability	83%	89%	80%
Price	61%	85%	84%
Billing & Payment	46%	65%	56%
Corporate Citizenship	89%	87%	85%
Communications	61%	85%	85%
Customer Care	56%	91%	87%

*OSAT is Overall Satisfaction

2. ACSI

The American Customer Satisfaction Index (ACSI) provides benchmarks by company for investor-owned energy utilities serving residential customers. As stated in our October 31, 2019 *Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives* report in this docket, we do not believe a subscription to ACSI offers survey results as robust as J.D. Power – whom we already subscribe to. For example, J.D. Power surveys approximately 3,000 Xcel Energy customers per year (approximately 1,100 Minnesota customers). We learned from ACSI in September 2019 that they survey approximately 600 Xcel Energy customers per year (or about 250 Minnesota customers). From a statistical perspective, there is lower confidence with the much smaller ACSI sample versus J.D. Power's larger sample. Additionally, J.D. Power has 142 peer utilities in its benchmark, while ACSI has 26. However, during the Commission hearing in this proceeding, we agreed to provide the public facing survey results that can be found on the ACSI website,[4] free of charge for Commission review. We include as Attachment B to this report ACSI's most recent survey results for IOUs, with key metrics including customer expectations, customer perceptions about the value and quality of their actual experiences, customer complaints, and customer retention.

B. Demand Response Metrics

In its April 16, 2020 Order, the Commission approved additional metrics for demand response including MWh and amount called for load shedding, shaping and shifting. Additionally, a wording adjustment for our final metric of load factor for load net of variable generation was approved, setting the baseline for this future metric. We discuss each of these metrics below.

1. Demand Response Capacity

The available capacity for our demand response portfolio in Minnesota is 754 megawatts (MW). Much of this is due to two programs that have been available for more than a decade: Saver's Switch (direct load control) and our Peak Control (or Electric Rate Savings) rates. The megawatt hours (MWh) savings for these programs are calculated on the available hours, but are minimal at 155,967 MWh; this is a result of the available hours being a small fraction of the total hours in a year.

The total amount called for demand response in 2020 was 0 MW and 1,030 MWh. This is a result of our controls occurring outside the Company's peak hours. In fact, most of our controls in 2020 were a result of a geo-targeting pilot testing to determine the impact of control at specific feeders rather than at system peak.

All of this load is considered load shed at this time, and therefore shows as being identical to "Amount of Demand Response that Sheds Load" below.

2. Amount of Demand Response that Shapes Load

Demand response activities for shaping customer load include specific customer rates such as time-of-use (TOU) and behavioral demand response. The Company's Residential TOU Pilot, Flex Pricing, launched in November of 2020. See Docket No. E002/M-17-775. The pilot will run for two years and is designed to study customer responses to price signals, targeted communications, and enhanced data access. Customer communications include regular emails and outreach via community partners. The community engagement efforts

---

[4] https://www.theacsi.org/industries/energy-utilities.

are largely multilingual, using community channels to ensure the Company reaches non-English-speaking participants. The Company has also proposed new TOU rates for commercial customers in Docket No. E002/M-20-86. The General Service TOU proposal is designed to reflect system hourly and seasonal costs with price signals that encourage customers to reduce peak demand, as well as to shift energy usage to periods that have a greater availability of renewable energy resources. The proposal is pending Commission review and may eventually serve as the successor to the Company's legacy time-of-day service. Once data has been compiled for the complete residential TOU pilot, we will include the results in a future report. Additionally, if the Commission approves our proposed Commercial General Service TOU, we are able to report the findings in our annual report if the Commission believes it valuable.

3. Amount of Demand Response that Shifts Load

Activities for shifting load include electric water heaters or commercial thermal storage. On February 1, 2020, the Company submitted its Load Flexibility Petition, Docket No. E002/M-21-101, which proposes four load flexibility pilots. The Company presented these proposals as a first step in meeting our commitment to optimize load to generation as required in these metrics. The proposed pilots are generally load shifting, with the exception of our Peak Flex Credit proposal, which also includes a shedding component. Our Load Flexibility Petition recommends measurement and verification and tracking that would be utilized for future annual reporting if approved. Today, the Company does not have any approved load shifting programs.

4. Amount of Demand Response that Sheds Load

As noted in B.1. above, the total amount of Demand Response for the Company falls into this category.

5. Load Factor for Load Net of Variable Renewable Generation

The "load factor for load net of variable renewable generation" metric was chosen as an appropriate metric as it is based on data of hourly generation by generation source that is currently tracked by the utility, and directly addresses the performance of aligning load through demand response to renewable generation sources. The metric reported for 2020 – 46.79 % – is the annual load factor for load on the Company's generation system when load provided by renewable generation sources are excluded. This load factor includes the load from hydro generation, which is not considered renewable generation for this metric. This metric will allow us to incorporate the results of the previous demand response metrics as they continue to evolve; however, this metric also accounts for further impacts such as energy efficiency, which is measured through our Conservation Improvement Program (CIP).

C. Environmental Performance

The Environmental Performance Outcome hosts seven metrics and three sub-metrics. Where 2020 results needed no additional explanation, the metrics are noted to "See Attachment A for 2020 results." Where additional explanation is necessary, it is provided below with the associated metric.

1. Total carbon emissions by (1) utility-owned facilities and PPAs and (2) all sources [See Attachment A for 2020 results]

2. Carbon intensity (emissions per MWh) by (1) utility-owned facilities and PPAs and (2) all sources [See Attachment A for 2020 results]

3. Total criteria pollutant emissions

We report criteria pollutant information for utility-owned facilities only. As explained in our October 31, 2019 *Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives* report, approximately 85% of criteria pollutant emissions associated with the electricity we provide to our customers are from units that Xcel Energy owns, meaning we have high confidence in the quality of the data because we have CEMS data, stack test data, and fuel consumption data for these sources. The remaining 15 percent of criteria pollutant emissions are from sources we do not own, associated with energy purchased either through PPAs or in the wholesale market. The quality of the emissions data for these sources is less certain; we may have some directly measured data from certain sources, but for the others we may have little insight into the generating source and the accompanying emissions.

In 2020, total criteria pollutant emissions from utility-owned facilities were:

- NO_x: 6,050 tons
- SO_2: 3,356 tons
- PM: 472 tons
- Mercury: 0.0435 tons
- Lead: 0.0532 tons

4. Criteria pollutant emission intensity (criteria pollutant emissions per MWh)

For this metric – which as above is for utility-owned facilities only – total tons of criteria pollutant emissions are divided by total generation from owned facilities. [See Attachment A]

5. CO_2 emissions avoided by electrification of transportation – Alternative & Original approach

In this metric, we report three sub-metrics as requested by the Commission – one that estimates CO_2 avoidance, and two that focus on encouraging charging behavior that will tend to use lower-carbon electricity.

a. Percent of EVs in Xcel Energy's MN service territory participating in managed charging programs or on whole-house TOU rates

For this metric, the Company proposed the following formula in our October 31, 2019 *Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives* report:

Customers on EV-specific managed charging rates or whole-house TOU rates who have self-identified as EV owners ÷ Number of EVs registered in Xcel Energy's service territory

In 2020, the percent of EVs participating in managed charging programs or on whole-house TOU rates was 7%. This may be an underestimate, as it does not include customers on whole-house TOU rates who have self-identified as EV owners, for which we do not currently have data. It also does not account for the fact that a small number of those customers may own more than one EV but would only be counted once in the numerator.

b. Percent of managed charging customers' residential EV charging load occurring during off-peak hours

For this metric, the Company proposed the following formula in our October 31, 2019 *Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives* report:

Total annual energy consumed (MWh) by EVs charging during off-peak hours at the residences of customers enrolled in Xcel Energy's EV TOU rates or other managed charging programs ÷ Total annual energy consumed (MWh) by EVs charging at residences of customers enrolled in Xcel Energy's EV TOU rates or other managed charging programs

In 2020, the percent of managed charging customers' residential EV charging load occurring during off-peak hours was 94%.

c. CO_2 avoidance estimate calculated from electric vehicle charging

In our May 6, 2019 *Comments* and December 12, 2019 *Reply Comments* in this docket, the Company proposed a method to estimate CO_2 avoidance based on the number of kWh provided for electric vehicle (EV) charging, the estimated electric driving miles thus enabled, and the estimated amount of CO_2 that would have been emitted had that same number of miles been driven on gasoline. This method focuses on light-duty EVs, which constitute the vast majority of EVs in our service territory. We proposed:

- To calculate CO_2 emissions from EV charging (except in the case of EV customers on an all-renewable tariff), metered kWh charging EVs would be multiplied by the system average CO_2 rate per kWh for the year in question, as reported to The Climate Registry and third-party verified.
- To calculate CO_2 that would have been emitted by gasoline vehicles, we would use a publicly-available estimate of average kWh/mile (e.g. 0.32 kWh/mile, from the Department of Energy Alternative Fuels Data Center) to estimate the number of miles driven on electricity provided by the Company; then estimate how much CO_2 driving that number of miles on gasoline would cause, based on data from EPA on grams of CO_2 per mile.
- The metric – CO_2 avoidance – would be the difference between the two. In the case of EVs charged on an all-renewable tariff, with RECs retired on the subscriber's behalf, there would be no deduction for CO_2 from EV charging.

We make two adjustments for this Annual Report while maintaining the essence of the calculation. First, the share of overall EV charging today that is separately metered remains relatively small. Over time, this share will increase, as more EV owners are either separately metered or enroll in a program such as EV Accelerate at Home, which provides a Level 2 charger with embedded load monitoring. However, today, a significant amount – in fact, the majority – of EV charging would be missed if this calculation only included separately metered kWh. Instead, we use the number of EVs in the Company's Minnesota service territory as of the end of 2020 (14,225[5]), multiplied by an estimate of the typical annual consumption per light-duty EV (4,179 kWh, an average for both PHEVs and BEVs).

The second adjustment is to the average electricity use per mile by EVs. Rather than the Alternative Fuels Data Center's 0.32 kWh/mile as proposed earlier, we use a slightly more conservative estimate – 0.364 kWh/mile – which uses data for light-duty EVs from www.fueleconomy.gov and incorporates a 10% charging inefficiency factor.

[5] Number of EVs on the road in Xcel Energy service territory in Minnesota, including PHEV and BEV, based on 2020 zip-code-level historical sales data from IHS.

As previously set forth in our May 6, 2019 *Comments* and December 12, 2019 *Reply Comments*, we use the Company's Upper Midwest annual system average CO_2 rate (pounds per kWh) to calculate CO_2 emissions from EV charging for customers not on a renewable tariff. We acknowledge there are a variety of possible rates that could be used: MISO marginal CO_2 rates, Xcel Energy marginal rates, Xcel Energy hourly average rates, and Xcel Energy annual average rates. Using MISO marginal CO_2 rates would clearly violate the Commission's design principle for this docket that "Metrics should seek to measure behaviors that are within a utility's control and free from exogenous influences, such as weather or market forces."[6] The Company has no control over which generation resources are on the margin in MISO, which is determined by exogenous influences, specifically market forces. Using Xcel Energy marginal CO_2 rates or hourly average CO_2 rates is possible – but would require data on what hours of the day EV charging has occurred, and either what units were on the margin in those hours or what the hourly average CO_2 rate was in those hours. This is theoretically possible once more EV charging is separately metered and time-stamped, but not applicable in this calculation, since it is based on a default value for typical annual consumption (kWh) per light-duty EV, regardless of what time of day those kWh were provided. Therefore, we continue to use Xcel Energy annual average CO_2 rates here.

A small number of EV customers were also renewable energy tariff subscribers – 51 Windsource customers – as of December 2020. We assume those customers subscribe to Windsource for their full consumption, and assign a CO_2 rate of 0 lbs./kWh to their EV charging.

Based on these assumptions, we estimate the Company provided approximately 59 million kWh for EV charging in 2020, which enabled an estimated 163 million electric miles.[7] Had those miles been driven on gasoline, about 72,729 short tons of CO_2 would have been emitted.[8] EV charging was responsible for an estimated 19,310 short tons of CO_2.[9] The difference between the two, 53,419 short tons, represents a reasonable estimate of CO_2 avoidance in 2020 from electrification of transportation. We believe this estimate is conservative, because it does not reflect that the Company's low off-peak rates encourage EV owners to charge at night, when renewable generation tends to be higher; this would be captured in a calculation using Xcel Energy hourly average CO_2 rates, but is not reflected here.

---

[6] *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Docket No. E002/CI-17-401, ORDER ESTABLISHING PERFORMANCE-INCENTIVE MECHANISM PROCESS at 12 (January 8, 2019).

[7] 14,225 EVs * 4,179 kWh annual consumption per EV = 59,233,146 kWh estimated total EV charging. 59,233,146 kWh ÷ 0.364 kWh/mile = 163,313,942 electric miles enabled.

[8] EPA estimates tailpipe emissions of about 404 grams CO_2 per mile for an average gasoline-powered passenger vehicle. See Greenhouse Gas Emissions from a Typical Passenger Vehicle | Green Vehicle Guide | US EPA.

[9] Assigning the Company's 2020 Upper Midwest CO_2 intensity of 0.652 lbs./kWh to the estimated 14,174 EVs not charged on a renewable tariff, and 0 lbs./kWh to the 51 EVs enrolled in Windsource as of December 2020.

6. CO_2 emissions avoided by electrification of buildings, agriculture, and other sectors

In our October 31, 2019 *Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives*, we recommended estimating CO_2 emissions avoided by electrification of buildings based on a comparison of CO_2 emitted to provide the same service (water heating, space heating, etc.) with electricity compared to a fossil fuel. Specifically, we proposed the basic formula:

(Annual average CO_2 emissions from the fossil electric appliances) – ((energy (in kWh) consumed by the electric appliance) * (Xcel Energy's annual system average CO_2 rate per kWh))

The Company has negligible building electrification to report for 2020. The current constraints on fuel-switching under the Conservation Improvement Program (CIP) rules have made it challenging for us to offer customers incentives to switch from natural gas to electricity for building space or water heating. The Company has supported legislation that would lift this restriction and allow efficient fuel-switching improvements under CIP if specified criteria are met.[10] We expect there will be more to report on this metric in future years, particularly if the fuel-switching constraint is lifted.

We have, in the meantime, filed a *Petition for Approval of Load Flexibility Pilot Programs and Financial Incentive Mechanism* (Docket No. E002/M-21-101), which proposes load flexibility pilots designed to promote system efficiencies by matching load to available resources at the system and local levels, reduce system needs by shedding peak load or shifting usage to off-peak times, and reduce CO_2 emissions by allowing customers to shift portions of their load to off-peak periods when carbon-free generation is highest. One of the proposed pilots is particularly relevant to this metric: a three-year Residential HVAC Optimization Pilot that will offer customers incentives for converting a natural gas water heater to an electric pump water heater, and for offsetting or replacing natural gas furnace usage with an air source heat pump or ground source heat pump. Additionally, customers installing a demand management-capable heat pump water heater will be invited to enroll in our demand response option, which provides both an enrollment incentive and ongoing incentive for shifting their water heating load to non-peak hours.[11] Because the load flexibility pilots are only proposed, not yet approved, we have no results to report for 2020.

[10] HF 164 / SF 227, the *Energy Conservation and Optimization Act of 2021*.

[11] The petition also includes 1) a Peak Flex Credit Rider Pilot, which will study a dispatchable, load-shedding program for commercial customers; 2) a Commercial Thermal Storage Pilot, which will study incentives for commercial customers to install thermal storage solutions for cooling and refrigeration; and 3) an EV Optimization Pilot, which will study the management of the grid impacts of electric vehicles by working with

We note that the proposed approach for calculating CO_2 emission benefits differs between these two dockets. The calculation in the current docket is relatively simple: estimating CO_2 that would have been emitted by natural gas or other fossil fuel appliances that are replaced through electrification, and subtracting CO_2 emitted (at the annual system average CO_2 rate per kWh) to power the new electric appliances. In the load flexibility petition, the calculation is more granular, using *hourly* system average CO_2 rates to quantify the emissions benefit of shifting electrified loads from hours with a higher CO_2 rate (e.g. more fossil generation on the system, serving peak demand) to hours with a lower CO_2 rate (e.g. more renewable generation on the system relative to demand). The latter calculation does not, in fact, include the initial emissions benefit of switching from natural gas to electricity.[12]

The simple approach in the current docket will be appropriate for beneficial electrification programs whose primary goal is to switch a load from natural gas to electricity, achieving emission reductions by shifting to an electric system that has a declining CO_2 rate from year to year, regardless of the time of day those new electric appliances consume electricity. The hourly average rate approach in the load flexibility petition will be appropriate for programs whose goal is to actively manage loads to lower-carbon hours within the day. We will report using both approaches in the coming years as more building electrification and load flexibility take place.

7. Fugitive Emissions of Methane

Xcel Energy is committed to reducing methane emissions throughout the natural gas supply chain, which includes actions we have taken on the portion of that supply chain that we control (the natural gas distribution system), as well as efforts to influence our natural gas suppliers to reduce methane emissions on the upstream and midstream portions (production, gathering and boosting, processing, transmission and storage of natural gas before it reaches our distribution system).

a. Reducing methane emissions from our system

On the distribution system we own and control, methane emissions are already minimal. We have a long history of implementing operational improvements that reduce methane emissions, including system upgrades and participation in EPA's Natural Gas STAR and Methane Challenge programs. We have significantly reduced emissions from our distribution system primarily through replacing cast iron and unprotected steel pipes with

---

customers to schedule daily EV charging outside the Company's system peak and stagger charging times to avoid demand spikes. The EV Optimization Pilot if approved is likely to yield additional results under the CO_2 emissions avoided by the electrification of transportation performance metric in the current docket.

[12] For details, see *Petition: Load Flexibility Pilot Programs and Financial Incentive Mechanism,* Docket No. E002/M-21-101 at 48-49.

protected steel and plastic. We have replaced all known cast iron distribution mains in Minnesota. As of 2020, 91% of our distribution mains and 97% of our distribution services were plastic, and another 8.4% of our distribution mains and 1.3% of our services were protected steel. A recent study[13] shows pipe replacement can reduce distribution system emission rates well below the national average. Moreover, the recently released Natural Gas Sustainability Initiative (NGSI) *Methane Emissions Intensity Protocol* estimates that, compared to cast iron distribution mains with a GHG emission factor of 1,157 kg/mile, protected steel distribution mains have an emission factor of 97 kg/mile and plastic distribution mains 29 kg/mile,[14] showing that converting to plastic and protected steel can dramatically reduce methane emissions. In addition to pipe replacement, we have also worked to avoid natural gas releases during system construction work, increased leak survey frequency, and replaced existing high-bleed controllers with low or no-bleed controllers where possible.

We report methane emissions from the distribution system annually through the EPA Mandatory Greenhouse Gas Reporting Rule, Subpart W. Based on our EPA reporting, we estimate the leak rate[15] from our distribution system was approximately 0.14% in 2019, the most recent year with data available.

In addition to the mandatory EPA reporting, we have also recently joined ONE Future, a coalition of 38 natural gas companies across the gas supply chain working to expand emissions reporting and collectively limit methane emissions intensity across the entire natural gas supply chain to 1% or less of throughput by 2025. In 2019, members of ONE Future significantly exceeded this 1% goal, registering a methane intensity of 0.334% across all segments (production, gathering and boosting, processing, transmission and storage, and distribution). By joining ONE Future, the Company is committing to keep our methane emissions rate at or below 0.2% from all areas of our natural gas operations, including the distribution system and some minor transmission and processing facilities.

b. Reducing methane emissions upstream

Emissions from upstream and midstream operations are outside of Xcel Energy's control, since all of these operations – production, gathering and boosting, processing, transmission and storage – occur before Xcel Energy receives natural gas. Including them in this

---

[13] *Direct Measurements Show Decreasing Methane Emissions from Natural Gas Local Distribution Systems in the United States*; Brian K. Lamb, Steven L. Edburg, Thomas W. Ferrara, Touché Howard, Matthew R. Harrison, Charles E. Kolb, Amy Townsend-Small, Wesley Dyck, Antonio Possolo, and James R. Whetstone; Environmental Science & Technology 2015 49 (8), 5161-5169; DOI: 10.1021/es505116p.

[14] NGSI *Methane Emissions Intensity Protocol*, Version 1.0, at pages 33-34. See ngsi_methaneintensityprotocol_v1.0_feb2021.pdf (aga.org).

[15] MMscf of methane emissions per MMscf of methane throughput.

environmental performance metric would appear to violate the Commission's design principle that "Metrics should seek to measure behaviors that are within a utility's control and free from exogenous influences."[16]

Nonetheless, Xcel Energy is working to influence these upstream and midstream emissions by working with our natural gas suppliers to better quantify and limit methane emissions across the supply chain. Our goal is for the natural gas we purchase to be produced, processed and delivered with the lowest methane emission rate possible. Starting with gas procurement for 2021, we included in our request for proposals a voluntary request for disclosure of methane intensity based on the NGSI *Methane Emissions Intensity Protocol* and best practices. In addition to the voluntary information request, we continue to monitor and support the growing market for "certified natural gas" – gas which has been certified by an independent third-party to be produced with a low methane intensity and advanced technology to measure and monitor methane emissions.

One of the challenges to procuring lower-methane gas is that much of NSP Minnesota's gas procurement is not directly from suppliers, but via marketers who are pooling gas from multiple suppliers and may have incomplete information on the production practices of those suppliers. This makes it difficult to accurately quantify the emissions associated with gas that we supply to our customers. However, we do know the majority of the gas we procure is sourced from Canada, and as a result we can be confident that our suppliers are being held to stringent regulatory requirements to limit methane emissions during production and processing. Canada recently committed to reducing methane emissions from the oil and gas sector by 40%-45% below 2012 levels, by 2025. We will continue to work with our producers and gas marketers to improve transparency in methane emissions across the supply chain to accurately quantify and reduce emissions associated with the gas that we supply.

c. Proposed methodology for reporting fugitive methane emissions

As discussed above, we report methane emissions from the distribution system annually through the EPA Mandatory Greenhouse Gas Reporting Rule, Subpart W. We propose relying on the EPA reporting to estimate methane emissions from the distribution system. This reporting is independently verified and publicly reported by EPA. Note that because EPA Subpart W data for 2020 is not yet available, the figure included in the Attachment A metrics list for our distribution system methane leak rate is for 2019. Due to the time required for verification, reporting to EPA and publication by EPA, Subpart

[16] *In the Matter of a Commission Investigation to Identify and Develop Performance Metrics, and Potentially, Incentives for Xcel Energy's Electric Utility Operations*, Docket No. E002/CI-17-401, ORDER ESTABLISHING PERFORMANCE-INCENTIVE MECHANISM PROCESS at 12 (January 8, 2019).

W data for a prior year is generally not available until the fall of the following year. In the performance metrics annual report each April, we propose to report this metric for two years prior (all other metrics being for the prior year).

As noted above, emissions from upstream and midstream operations are outside of Xcel Energy's direct control, and requiring quantitative reporting metrics for reducing these emissions would therefore appear to violate the Commission's design principles in this docket. For this reason, we propose reporting a quantitative metric only for methane emissions on the Company's distribution system. However, we are willing to provide in the next annual report in this docket: 1) an update on our work to support transparent standardized reporting of upstream and midstream methane emissions, including methane intensity information collected from voluntary disclosures by suppliers in 2021, and 2) an update on any purchasing of certified gas in 2021.

III. STAKEHOLDER DISCUSSIONS AND ASSOCIATED FILING REQUIREMENTS

The Commission's April 16, 2020 Order directed the Company to engage in stakeholder discussions and development of a demand response financial incentive as well as exploration of a performance dashboard. We provide additional detail on each of these requirements below.

A. Demand Response Financial Incentive

Page 8 and Order Point 1.f. of the Commission's Order directed Xcel Energy to work with stakeholders and the Department to develop a demand response financial incentive. Order Point 1.f. states as follows:

> Furthermore, the Commission will direct Xcel to work with stakeholders and the Department to develop a demand response financial incentive, and to file a proposal for Commission consideration by the end of the first quarter of 2021. Demand response is an important resource for keeping the evolving grid efficient and reliable, and it can reduce peak demand, resulting in cost savings for customers and for the utility. It is important to begin the process of researching and considering financial incentives to encourage achievements in demand response when such achievements would be beneficial to the utility system and to customers.

In compliance with that Order, the Company held three stakeholder meetings to discuss not only a demand response financial incentive mechanism, but the programs that would be included in such a calculation. Pursuant to two Commission Orders, on February 1, 2021, in Docket No. E002/M-21-101, we submitted a petition presenting our load flexibility plan for 2021 through 2023. The first Order is the Commission's April 16, 2020 ORDER ESTABLISHING METHODOLOGIES AND REPORTING SCHEDULES in this docket, the second is the Commission's December 15, 2020 ORDER ESTABLISHING DEMAND RESPONSE COMPLIANCE DOCKET AND FILING REQUIREMENTS in Docket No. E002/M-20-421. Our Petition requested approval of four new load flexibility pilots, a load flexibility program development budget including two demonstration projects, and a performance based financial incentive mechanism. We believe our proposed incentive mechanism balances the general disincentive for a utility to pursue load flexibility resources while also including performance components based on program success, governed by a cap to ensure the programs provide net benefits over time. We look forward to continued dialogue regarding our proposal in Docket No. E002/M-21-101.

We provide the filed summaries of related stakeholder meetings - including PowerPoint presentations and The Brattle Groups Load Flexibility Potential Study - held on October 6, October 20, and November 10, 2020 as Attachments C, D and E, respectively, to this report.

B. Dashboard

The Commission directed the Company to:

> [E]xplore and develop options to employ an online utility performance dashboard and present those options to the Commission in the first annual report. Many stakeholders have expressed interest in an online dashboard to make the metric data more transparent and accessible to the public, and the Commission agrees that public access to data is an important goal. However, the Commission needs more information before it can determine whether to require the development and use of an online dashboard. The Commission will direct Xcel to further develop this idea in consultation with interested stakeholders, including a fair and complete discussion of the costs that may be involved.

A stakeholder discussion was held to address this compliance point. To inform the discussion, we provided information on utilities around the country that produce annual metric reports. We reviewed reporting of the following utilities: Commonwealth Edison and Ameren (both located in Illinois), National Grid (located in Massachusetts), and Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric (all three of which are located in California). Although the California utilities have metrics, we were unable to find them on the California Public Utilities Commission or the individual utilities website(s).

1. Utility / Regulator Online Dashboard Options

The Company reviewed two active online dashboards with differing hosts. One dashboard option was hosted by Hawaiian Electric Company (HECO) and the other hosted by a regulator, the Ontario Energy Board (OEB). HECO's website is likely the most well-known and comprehensive online dashboard example and was raised by the performance based rates (PBR) workgroup at different times. The Company met with the HECO regulatory and website management group to learn about its development and functionality.

The performance metric portion of the website was borne out of a decoupling settlement; therefore, they did not know the specific development costs associated with the PBR development itself. However, they estimate annual maintenance – which includes staff resources as this is a labor-intensive process – to be approximately $240,000. HECO's version is a simplified option of subject matter experts providing verified and approved data at monthly intervals on an excel spreadsheet; the data is then moved to Microsoft Word and published to their website. The data can be viewed in charts and graphs, as well as historical.

The Ontario Energy Board (OEB) regulates 66 Canadian distribution utilities, and metric reporting is hosted on the OEB's website. The OEB's online PBR metric dashboard provides a variety of views from individual utility to a comparison of certain items for all reporting utilities. Utilities report their information to the OEB, and OEB creates the public facing dashboard. Labor costs for managing the tool and compiling the comparison data are borne by the regulatory body. While each utility reports the "metrics" themselves, they are provided the opportunity to supplement the data with "discussion and analysis." We found no cost estimates or allocations.

The fully documented Q&A between participants is provided in a summary of a March 2, 2021 workshop with stakeholders as Attachment F to this report.

2. Xcel Energy Dashboard Development Option(s)

Cost estimates to develop an online metric dashboard using Xcel Energy's website were provided to the stakeholder group and vary significantly, but without specific data requirements and the Commission's expectations for data access, it is difficult to derive an estimate at this time. A more cost-friendly approach that appears to be user-friendly is the HECO online dashboard. Using this approach, the subject matter experts pull, verify, and upload their information in a Microsoft Excel spreadsheet. Next, the website management team transfers the information to Microsoft Word and uploads to preset graphs and links on the Company's website. We estimate this would cost approximately

$125,000 to develop (depending on the requested criteria and capabilities) with annual maintenance of approximately $200,000.

If we consider building something more extensive that was automated and/or linked to the Commission website, the costs would increase and could reach $1.5 million. Development and maintenance costs depend on the extensiveness, capabilities, automation, and cyber security measures required of the dashboard interaction.

Lastly, the stakeholder group thought it would be valuable to develop an illustration in order to visualize an online scorecard/dashboard and to help frame the context, necessity and usability of such a tool. The proposed illustration would depict the Commission's approved five Outcomes: Affordability, Reliability, Customer Service Quality, Environmental Performance, and Cost-Effective Alignment of Generation and Load. The illustration will include some of the associated metrics under these outcomes and will be split to the best of our ability into residential and commercial. The illustration does not include all 28 approved metrics, but will include the items we believe are of the greatest importance to our customers.

Attachment G is the illustrative scorecard we discussed with the stakeholder group utilizing the smaller subset that we believe parties may be most interested in, including:

- Average monthly bills for residential customers
- SAIDI
- Number of Customer Complaints
- Total carbon emissions by (1) utility-owned facilities and PPAs and (2) all sources
- Demand response, including (1) capacity available (MW & MWh)

As the scorecard is for illustrative purposes, we have provided five years of data. Should the Commission determine it would like us to look further in the development of an annual scorecard, we ask for the opportunity to develop a full proposal based on comments and feedback received on the scorecard illustration in this report.

3. Considerations

In determining the relevance and necessity of a dashboard in relation to cost, we recommend the Commission first consider a subset of the list of metrics as well as the end-user. Other considerations include: where the data should be housed and accessed (Xcel Energy's website, the Department of Commerce website, or the Commission website), what level of detail is required, and what level of system sophistication and automation is desired. These elements will help determine the cost to develop and maintain a dashboard.

C. Work With Stakeholders to Develop Evaluation Criteria and Benchmarks and File Them at a Later Date

The Commission's April 16, 2020 Order identified a future metric, to develop evaluation criteria and benchmarks with stakeholders. Specifically, the Order states:

> Similarly, the Commission will direct Xcel to work with stakeholders to develop evaluation criteria and benchmarks and file them at a later date. The Commission will wait until the appropriate step in the PIM process to decide on criteria for good versus bad performance, and establish benchmarks against which to measure Xcel's performance; however, the process of evaluating such criteria and benchmarks is likely to be complex and time-consuming, and the Commission will direct Xcel and stakeholders to begin that process.

Further, the Order also notes our position on benchmark development:

> Xcel also stated that it believed it was not yet time to set benchmarks for comparison or develop evaluation criteria for good versus poor performance; rather, appropriate comparison data should be developed at a later stage, after Xcel has consistently provided reports of existing data.

We appreciate the Commission's consideration in this matter and ask to provide our annual reports for three years (2021 through 2023 reports for 2020 through 2022 data) prior to developing the benchmarking criteria. We believe this provides an adequate timeframe to develop a record and for all parties to meet to assess appropriate benchmarking criteria.

IV. COMMISSION ORDERED FOLLOW-UP AND REPORTING

A. Workforce and Community Development Impact – Metric

During the stakeholder metric development process, the group discussed two proposed concepts and generally agreed they may provide some value in measuring the correlation between workforce and community development impacts. The first was to develop a workforce transition plan with data relative to plant closures to analyze attrition, skill gaps, workforce impacts, etc., and how we plan to address the impacts as a result of plan closures. The second was to utilize one or more workforce diversity reporting methodologies to be recommended by the Commission Energy Utility Diversity Group (EUDG) in Docket No. E,G999/CI-19-336. We offer an option for each but recommend at this time to begin any required reporting on one workforce related metric.

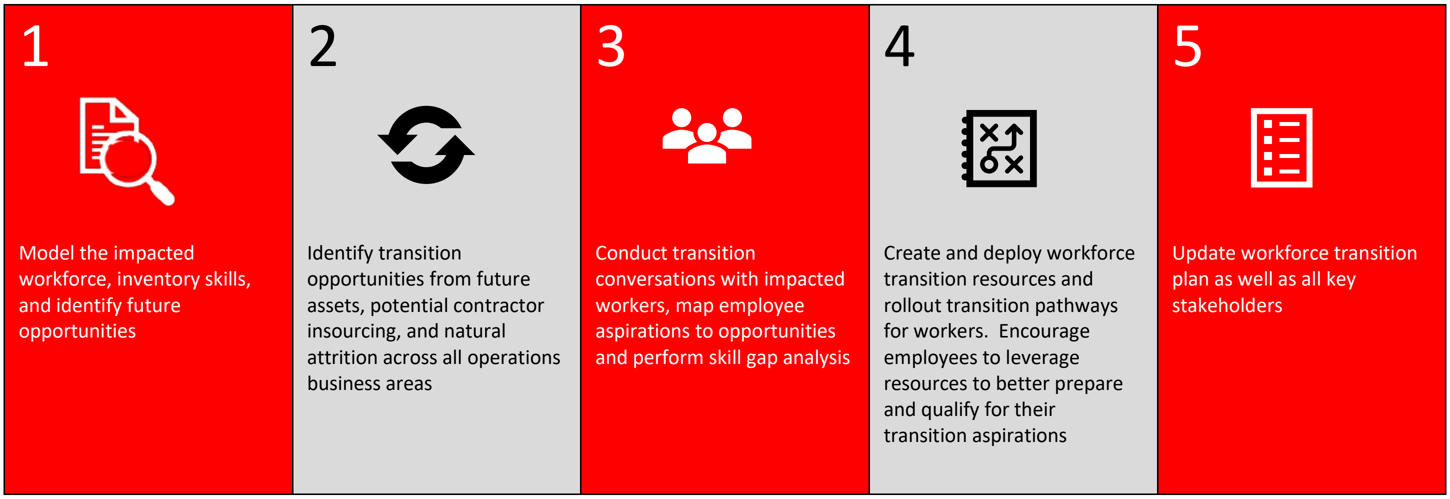
1. Workforce Transition Plan

The impact of our generation plants on the communities that surround them is meaningful. Our plants contribute significantly to the local city, county, and school tax base, and many plant employees live in the neighboring communities or counties. Within this Workforce Transition Plan, we could report on items such as number of employees lost through natural attrition (*i.e.*: retiring, number severing, and number of employees retrained or reassigned). This has not formally been reported previously, and as we stated in our October 31, 2019 *Proposed Metric Methodology and Process Schedule on Performance Metrics and Incentives* in this docket, we are open to feedback on this proposal and want to better understand the full benefits of this plan for the public and how it can be utilized to help in community-wide planning.

During the stakeholder meetings, parties recommended the Company and the Center for Energy and Environment (CEE) meet to discuss the study CEE was undertaking and completed in February 2020 entitled *Minnesota's Power Plant Communities: An Uncertain Future*. We worked closely with CEE during the development of the report, as it assessed the impacts of future closures to four of our generating plants. A copy of this report is included as Attachment H.

Stakeholder conversation at the time of the PBR metric development largely focused on the impact to employees and the community as a result of Xcel Energy moving toward cleaner energy sources resulting in the closure of coal plants. The group was particularly interested in our plans for displaced workers. Below is an outline of phases and how we plan to address this issue. This process is currently being conducted in Colorado and will be replicated in Minnesota, beginning this fall. This plan has recently been shared with the Minnesota International Brotherhood of Electrical Workers (IBEW) locals that will be affected. We propose that we provide the final plan report as a response to this request for stakeholder review and feedback in our April 30, 2022 annual report. The plan will consist of the following:

Figure 1
Workforce Transition Plan



Minnesota Coal Plants – Workforce Transition Plan Detailed Description Plant Modeling

- Create workforce models in collaboration with Resource Planning and Plant Management
- Establish cadence for communicating model outcomes
- Align and adjust transition planning process based on feedback

Skill and Solution Inventory

- Connect with XE stakeholders, local education providers, and industry education providers to identify potential solutions
- Evaluate and report possible opportunities for workers to transition
- Inventory skills and create first draft of skill gap analysis

Set the stage for transition

- Engage HR team for transition conversations
- Kick-off operations leadership alignment for transition discussions
- Support and deploy presentations to plant workers
- Support plant leadership in communicating with workers through a kickoff event

Transition Conversations

- Conduct transition conversations with plant workers
- Train leaders on how to support workers through transition
- Refresh standard deliverables to workers, in collaboration with education providers

Data Analysis and Solution Development

- Process data, finalize skills gaps, report summary of transition preferences
- Perform gap analysis and map to existing solutions
- Report first draft transition plan to key stakeholders
- Operations leadership alignment for transition workshop and draft execution of plan
- Conduct solutions workshop and analyze cost of solutions
- Key stakeholder review/approval of solutions

Transition Rollout

- Create transition plan/pathways for workers
- Roll out the individual transition plans/pathways
- Create/deploy training
- Update and finalize transition plan

To the extent feasible, the Company does not anticipate any layoffs. Our intent is to re-skill, up-skill, transfer and/or relocate these workers. Some workers may choose to exit the Company rather than participate in the transition process. While a success metric of this plan may include the number of workers transitioned, it is important to keep in mind that many may choose differently, but the Company will work to the best of its ability to transition those that are interested.

Figure 2
Example of Proposed Workforce Plan Report

2. Workforce Diversity Reporting Methodologies

Minnesota Session Laws, 2019, First Special Session, Chapter 7, Article 11, Section 13 directed the Commission to convene a stakeholder group in 2019 to examine the challenges and opportunities for Minnesota's energy utilities to attract a diverse workforce with the skills needed to advance a 21st century industry and to increase supplier diversity of energy utilities. The group was self-titled the Energy Utility Diversity Group (EUDG). The EUDG workgroup consisted of more than 70 stakeholders ranging from utilities to cities to interested parties and advocacy groups. The stakeholder group's recommendations as previously reported to the Commission are listed below. The utility group had varying abilities to collect and store data as well as offer training and education programs. Many utilities submit annual Affirmative Action compliance reports to the State of Minnesota's Department of Human Rights. We include as Attachment I the report we submitted in 2020 for the period of April 1, 2019 – March 31, 2020. While the dates will not align perfectly with the Commission's expressed January – December desired timeframe, an ongoing 12-month range would be represented with a three-month roll-over.

The Affirmative Action Plan we filed for MN in 2020 indicates:

- We have identified no underutilization of women or people of color in our current workforce. We will continue to monitor our workforce composition to ensure that no problems arise.
- Personnel activity: We will routinely conduct adverse impact analyses using the "Eighty Percent Test" or other statistical methods to analyze our personnel activities, including applicant flow, hires, promotions, terminations and other personnel actions, to determine if there are selection disparities between men and women, people of color, nonminority (and within specific racial groups, if appropriate), or disabled and nondisabled applicants or employees. For tests that are used as a part of our selection process, we confirm these tests are job-related and are validated. We have taken corrective action to remove any barriers to hiring or retaining women, people of color, or individuals with disabilities.
- Personnel procedures: We will routinely review all of our personnel procedures and processes, including selection, recruitment, referral, transfers and promotions, seniority provisions, apprenticeship programs and company-sponsored training programs and other company activities to determine if all employees or applicants are fairly considered.
- Any other areas that might impact the success of our Affirmative Action Program: We continually analyze any other areas that may impact our success, such as accessibility of our facility to the available workforce, the attitude of our current workforce towards EEO, proper posting of our

EEO policy and required governmental posters, proper notification of our subcontractors or vendors, and retention of records in accordance with applicable law. We take prompt action to remedy any problems in these areas through training of staff or other methods.

We enclose the report as submitted to the Legislature on January 15, 2020 as Attachment J.

a. EUDG Report Recommendations

Data collection: Collecting data allows utilities to know where they currently sit, as well as inform their goals for the future. It is recommended that utilities continue to use required affirmative action plans as a starting place for strategic planning. For utilities that are not required to file demographic information with the State, the affirmative action reporting templates and guidelines could voluntarily be used to help utilities track demographics information.

Build on current efforts in engagement, building pipelines, training and hiring practices: Energy utilities should continue their existing recruitment, training, retention (including professional development, cultural competency, and skill development), and outreach programs and allocate resources for programs to cultivate diversity at all levels.

- Emphasize ongoing efforts: Rather than one-time engagement efforts, there must be an ongoing dialogue between industry stakeholders, educational entities and the communities they serve.
- Build pipelines: Career exposure should start during high school or earlier for students and young people, and employers should establish and maintain relationships with targeted schools and populations and engage consistently and regularly with students over time. This includes educating young people on the energy industry as well as providing tools and programs to gain fundamental knowledge of the industry. Establish programs in middle and high schools where students can explore and learn about the industry and guide students into the post-secondary programs that will provide the education they need to obtain employment in the industry. This should be done while continually tracking and maintaining contact with these young people through industry mentors or other contacts.
- Expand training: It is important to expand training opportunities for diverse populations, including registered apprenticeships, paid internships, and paid fellowships, to help identify and nurture professional skills.
- Analysis of hiring requirements and reducing barriers: Energy utilities should review their existing recruitment and hiring practices to ensure that

job-entry requirements are appropriately aligned with the actual requirements of the job. Special attention should be paid to acknowledging and removing existing barriers.

Partner with other utilities: Recognizing that different utilities have different levels of resources and staff capacity, some utilities might work jointly with other utilities to allocate resources and funding to explore innovative outreach and awareness models, including:

- New methods of reaching particular diverse groups through existing energy services. For example, utilities might integrate information about career opportunities into the provision of their services such as energy efficiency upgrades in underrepresented communities.
- Coordinated and targeted marketing campaigns to build awareness of the utility industry, especially within low-income communities, immigrant communities, and communities of color.
- Establishing "energy experience centers" located in accessible locations, including Opportunity Zones, within underrepresented communities in order to ensure access and expose youth and adults to energy technologies and educational opportunities, and to create hubs where interested individuals and businesses could connect with utilities, vendors, and training providers.
- Expanding and/or replicating community and school-based programs that support STEM learning, like the CEWD school curriculum or mentoring programs such as the Future Cities Competition, which pairs energy utility professionals with students to provide STEM tutoring and career pathways guidance. There has been a re-emergence of technical education programs at the high school level. Utilities can further support STEM education by engaging with these facilities.
- It is important for the State of Minnesota and school districts serving diverse populations to invest in closing achievement and opportunity gaps and improving retention and graduation rates for racial and ethnic minority students in low-income/under-resourced households, and students from immigrant populations.
- Addressing transportation barriers will likely also need assistance from entities outside the utility sector to help ensure that potential employees have reasonable access to training and jobs.

Investment from the State: Solutions likely will not come from the energy sector alone.

Recognize positive impact of utility ownership: The impact of diversity efforts in the regulated electric utility sector may be greatest where generation and transmission assets are owned by utilities, because third-party owners are not currently held to the same equity and transparency standards. Minnesota's agencies, boards and commissions are encouraged to recognize and weigh the impact of utility ownership on diversity where consistent with their legal authority. The legislature should also consider taking steps to ensure that Independent Power Producers and other beneficiaries of ratepayer-funded subsidies for distributed generation and energy efficiency programs, including Community Solar Gardens, be required to meet the standards as regulated utilities.

Partner with non-utilities: Energy utilities should explore partnering with industry partners, building trades unions, academic institutions, community-based organizations, and workforce agencies to identify and develop career pipelines, while making the training and employment opportunities more accessible to underrepresented populations.

Continue this process: The EUDG can continue their work to gather many stakeholders to discuss challenges, successes, resources and best practices in regard to increasing workforce diversity.

CONCLUSION

In conclusion, we have provided reporting for the 28 metrics the Commission approved on April 16, 2020 for the period of January 1 2020 through December 31, 2020. We also provide for Commission review stakeholder dashboard discussion and an illustrative example as well as two workforce and community development impact options for consideration.

As stated earlier in this docket and in this report, we continue to recommend tracking and reporting the initial metrics ordered by the Commission for a period of three years to determine if those metrics are the correct ones to be tracking and if they remain valid as time goes by. We also recommend that after three years of reporting, we revisit the metrics in this docket to ensure the Company is addressing the correct ones.

We welcome any questions the Commission and parties may have about our 2020 Performance Metrics Annual Report and look forward to providing future annual updates. Thank you for the continued opportunity to participate in this proceeding.

Dated: April 30, 2021

Northern States Power Company

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
Affordability					
1	Rates per kWh based on total revenue, reported (1) by customer class and (2) with all classes aggregated	NEW	NSPM-MN customers only.	Residential: $0.13740/kWh Commercial: $0.10494/kWh Industrial: $0.07975/kWh Total Customers: $0.10908/kWh	__________
2	Average monthly bills for residential customers	NEW	Report annually: Total Annual Residential Class Revenue / Total Number of Residential Customers Served	$88.28	__________
3	Total disconnections for nonpayment for residential customers	CURRENT	Continue same system-generated process to determine total disconnections for nonpayment used in Quality Service Plan (QSP) reports, Cold Weather Rule, and Annual Electric Low Income Discount reporting. Process includes internal system-generated reporting of monthly disconnections on a Commission-approved template per Minn. Stat. § 216B.091.	2,819	__________
4	Total arrearages for residential customers	CURRENT	Continue same calculation process to determine total arrearages for reporting in Quality Service Plan (QSP) reports, Cold Weather Rule, and Annual Electric Low Income Discount reporting. Process includes internal system-generated reporting of monthly bad debt where arrears are calculated by company, customer type, active/inactive, number days overdue.	$60,838,363	__________
Reliability					
1	System Average Interruption Duration Index (SAIDI): Indicates average interruption duration per customer during defined period of time.	CURRENT	Report with and without major event days. Sum of Total Sustained Customer Interruption Durations Total Number of Customers Served "Sustained event" = duration of more than 5 minutes **Order Point**: Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	All Days: 134.19 Annual Rules Normalized: 98.92	__________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
2	System Average Interruption Frequency Index (SAIFI): Indicates average number of sustained interruptions per customer over defined period of time.	CURRENT	Use Jan–Dec each year to align with current reporting. Report with and without major event days. Proposed formula: <u>Sum of Total Sustained Customers Interrupted</u> Total Number of Customers Served **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	All Days: 1.07 Annual Rules Normalized: 0.99	________
3	Customer Average Interruption Duration Index (CAIDI): Indicates average time to restore service to customers that have been interrupted from sustained event.	CURRENT	Report with and without major event days. Proposed formula: <u>Sum of Total Sustained Customer Interruption Durations</u> Sum of Total Sustained Customers Interrupted **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	All Days: 124.89 Annual Rules Normalized: 100.28	________
4	Customers Experiencing Long Interruption Duration (CELID): Indicates ratio of customers experiencing interruptions with duration equal to or greater than "d" during defined period of time.	CURRENT	Report with and without major event days. Proposed formula: Total Number of Customers that experienced <u>interruptions of “d” or more hours duration</u> Total Number of Customers Served Propose “d” = 24 hours. Consistent with annual Service Quality Plan, where customers experiencing outage of 24 hours or more receive $50 bill credit for each outage occurrence lasting longer than 24 hours. **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	All Days: 0.339% Annual Rules Normalized: 0.133%	________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
5	Customers Experiencing Multiple Interruptions (CEMI): Indicates ratio of individual customers experiencing more than "n" sustained interruptions to total number of customers served.	CURRENT	Report with and without major event days: Total Number of Customers that experience more than "n" sustained interruptions Total Number of Customers Served Propose "n" to be 5 sustained interruptions. Consistent with annual Service Quality Report, where customers experiencing more than 5 sustained interruptions in a year receive $50 bill credit. **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	All Days: 0.538% Annual Rules Normalized: 0.366%	________
6	Average Service Availability Index (ASAI): Similar to SAIDI - is percentage of time service is available. (Whereas SAIDI is average total amount of time service is unavailable.)	CURRENT	Report with and without major event days: Customer Hours Service Availability Customer Hours Service Demanded **Order Point:** Direct Xcel to use a Normalization method consistent with the Commission's most recent Order in the Annual Service Quality, Safety, and reliability docket in reporting their SAIDI, SAIFI, CAIDI, CELID, and ASAI within this docket.	All Days: 99.9745% Annual Rules Normalized: 99.9812%	________
7	Momentary Average Interruption Frequency Index ($MAIFI_E$) The amount of momentary inturruptions a customer would experience during a period of time.	CURRENT*but not with AMI technology, under captured today (Report in 2026)	Report with and without major event days: Sum of Total Momentary Customer Interruptions Total Number of Customers Served Momentary events = having duration of less than or equal to 5 minutes.	Discussion in narrative.	________
8	Power Quality	NEW (Report in 2026)	None currently. Could be tracked, and percent of customer exceptions can be reported with AMI data. Specific capabilities still being developed and will be determined over the coming years.	Discussion in narrative.	________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
Customer Service Quality					
1	Existing multi-sector metrics, including ACSI and J.D. Power	NEW	Reporting from Xcel Energy's subscription to J.D. Power and public information published by ACSI.	JD Power discussion in narrative. ACSI Study: https://www.theacsi.org/index.php?option=com_content&view=article&id=149&catid=&Itemid=214&i=Investor-Owned+Energy+Utilities	Attachment B
2	Call center response time: Measures telephone response time.	CURRENT	Calls answered by a call center representative within 20 seconds + all calls handled via self-service in the Interactive Voice Response (IVR) system Total calls into our call centers or business office	85.8%	__________
3	Billing invoice accuracy: Measures percent of accurate invoices Xcel Energy issues to customers.	CURRENT	Number of invoices canceled for controllable reasons Total number of invoices issued "Controllable reasons" = human errors made by field or office personnel, billing system and metering system communications errors, and malfunctioning meter equipment.	46,006 controllable cancel rebills in 2020, 24,776,452 invoice sent in 2020. Data is from M2M Detailed Reports 46,006/24,776,452 = 99.99% accurate	__________
4	Number of customer complaints: Measures number of complaints based on number of complaints per 1,000 customers to regulatory agencies to ensure performance is measured in relation to total customer base.	CURRENT	Number of MPUC Complaints < Number of Customers/1000 x 0.2059	1,782,621/ 1000 x 0.2059= 367 239 MPUC complaints by Xcel Energy < 367 2020 Threshold per QSP calculation The calculation for the per 1000 customers is: 1,782,621 Customers/1000 = 1782.621, number of complaints 239: Calculation 239/1782.621 =.1341 which is less than the .2059 threshold.	__________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
Environmental Performance					
1	Total carbon emissions by (1) utility-owned facilities and PPAs and (2) all sources	NEW	Leverage Xcel Energy reporting to The Climate Registry (TCR) by data "pools." • Pool 1 = owned zero-emission facilities • Pool 2 = owned fossil electric generating units (EGUs) equipped with continuous emission monitoring systems (CEMS) • Pool 3 = owned fossil EGUs not equipped with CEMS • Pool 4 = purchased power agreements (PPAs) • Pool 5 = short-term and spotpurchased power from known sources (to which we can ascribe a specific emissions) • Pool 6 = short-term and spot-purchased power from unknown sources in MISO market (to which we cannot ascribe a specific emissions rate so apply regional grid average CO2 rates from EPA). In calculating total carbon emissions from utility-owned facilities and PPAs only, include Pools 1-4 only. In calculating emissions from all sources, include Pools 1 through 6. We include CO2 from MISO market purchases, but deduct CO2 from trade margin sales, since this energy does not serve customers, and if energy purchasers report this CO2, would result in double-counting.	(a) Utility -owned facilities and PPAs = 12,710,943 tons (b) All sources = 12,801,300 tons.	___________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
2	Carbon intensity (emissions per MWh) by (1) utility-owned facilities and PPAs and (2) all sources	NEW	For carbon intensity from utility-owned facilities and PPAs only, divide total CO2 from Pools 1-4 by total generation (MWh) for resources in those pools to derive CO2 intensity in pounds per MWh. For carbon intensity from all sources, divide total CO2 from Pools 1-6 by total generation (MWh) for resources in those pools to derive CO2 intensity in pounds per MWh. We include CO2 from MISO market purchases, but deduct CO2 from trade margin sales, since this energy does not serve customers, and if energy purchasers report this CO2, would result in double-counting.	(a) Utility -owned facilities and PPAs = 640 pounds per MWh (b) All sources = 643 pounds per MWh.	__________
3	Total criteria pollutant emissions	NEW	Report criteria pollutant information for utility-owned facilities only. Nitrous oxide (NOx) and sulfur dioxide (SO2) emissions are tracked based upon state and federal monitoring requirements. Various emissions monitoring methods are used, depending upon facility and pollutant, including CEMS, fuel flow and fuel analysis. For particulate matter (PM), emissions are tracked based on allowed state reporting methodologies including stack test data and use of EPA AP-42 emission estimates.	• NOx: 6,050 tons • SO2: 3,356 tons • PM: 472 tons • Mercury: 0.0435 tons • Lead: 0.0532 tons Additional discussion in narrative	__________
4	Criteria pollutant emission intensity per MWh	NEW	Track and report emissions of NOx, SO2 and PM as proposed for "Total criteria pollutant emissions," and then divide those figures by total MWh of generation to derive criteria pollutant emission intensity.	• NOx: 0.416 pounds per MWh • SO2: 0.231 pounds per MWh • PM: 0.032 pounds per MWh • Mercury: 0.000003 pounds per MWh • Lead: 0.000004 pounds per MWh	__________
5(a)	CO2 emissions avoided by electrification of transportation – Alternative & Original approach	NEW	Percent of EVs in Xcel Energy's MN service territory participating in managed charging programs or on whole-house TOU rates. Proposed formula: Customers on EV-specific managed charging rates or whole-house TOU rates who have self-identified as EV owners Number of EVs registered in Xcel Energy's service territory	7% Additional discussion in narrative.	__________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
5(b)	CO_2 emissions avoided by electrification of transportation – Alternative & Original approach	NEW	Percent of managed charging customers' residential EV charging load occurring during off-peak hours. Proposed formula: $$\frac{\text{Total annual energy consumed (MWh) by EVs charging during off-peak hours at the residences of customers enrolled in Xcel Energy's EV TOU rates or other managed charging programs}}{\text{Total annual energy consumed (MWh) by EVs charging at residences of customers enrolled in Xcel Energy's EV TOU rates or other managed charging programs}}$$	94% Additional discussion in narrative.	___________
5(c)	CO_2 emissions avoided by electrification of transportation – Alternative & Original approach	NEW	CO_2 avoidance calculation as proposed in 12/12/19 Reply Comments: • To calculate CO_2 from EV charging (except in the case of EV customers on an all-renewable tariff), metered kWh charging EVs would be multiplied by the system average CO_2 per kWh for the year in question, as reported to The Climate Registry and third-party verified. • To calculate CO_2 that would have been emitted by gasoline vehicles, we would use a publicly available estimate of average kWh/mile (e.g. 0.32 kWh/mile, from the Department of Energy Alternative Fuels Data Center) to estimate the number of miles driven on electricity provided by the Company; then estimate how much CO_2 driving that number of miles on gasoline instead would cause, based on data from EPA on grams of CO_2 per mile. • The metric – CO_2 avoidance – would be the difference between the two. In the case of EVs charged on an all-renewable tariff, with RECs retired on the subscriber's behalf, there would be no deduction for CO_2 from EV charging.	53,419 tons Additional discussion in narrative.	___________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
6	CO2 emissions avoided by electrification of buildings, agriculture, and other sectors	NEW	Calculate CO2 avoidance based on comparison of CO2 emitted to provide same service (water heating, space heating, etc.) with electricity vs. with fossil fuel. Proposed formula: (Annual average CO2 emissions from the fossil electric appliances) – ((energy (in kWh) consumed by the electric appliance) * (Xcel Energy's annual system average CO2 rate per kWh))	No quantitative results to report for 2020 Additional discussion in narrative.	__________
7	Discussion of fugitive emissions of methane, including proposed methodology for reporting fugitive emissions for methane	NEW	Not included in proposed metrics and methodologies, but ordered by Commission (April 16, 2020 Order, order point 1.d)In Reply comments address our position i. Fresh Energy's proposed methan leakage rate value of 3%; the Department's recommended leakage rate of 1.87% (Department changed to .2% at the hearing); or None or <.2% based on reporting to the EPA under subpart W of the GHG Reporting Program.	Methane emissions rate on NSPM Gas distribution system controlled by Xcel Energy was 0.14% in 2019, as reported to EPA Mandatory Greenhouse Gas Reporting Rule under Subpart W. Note that for this Environmental Performance metric only, the reported data is for 2019 not 2020, since Subpart W data for 2020 is not yet available as of April 2021. Additional discussion in narrative.	__________
Cost Effective Alignment of Generation and Load					
1	Demand response, including (1) capacity available (MW & MWh) and (2) amount called (MW, MWh per year)	CURRENT	System Generated	Total Capacity Available in MN (summer 2020) 754.6 Gen. MW and 155,967 Gen. MWh. Total Actual Capacity called (2020) 0 Gen. MW and 1,030 Gen. MWh.	__________
2	Integration of customer loads with utility supply - Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns.	NEW/TBD	Actual MW at system peak hour before and after rate initiation or the start of a behavioral program. As these programs mature it, will be necessary to determine how participants load would have grown over time without the program. Forecasted load avoided will be based on actual trends over time.	Shaping activities such as fuel switching and time of use rates are still being reviewed as part of our pilot efforts or before the Commission for approval. Additional discussion in narrative.	__________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
3	Integration of customer loads with utility supply - Amount of demand response that SHIFTS energy consumptions from times of high demand to times when there is a surplus of renewable generation.	NEW/TBD	Available MWh during times contingency events and/or shifts to particular times of the day over time. Calculations would likely be based on assumptions until a larger population of customers can be analyzed through a measurement and verification process to verify reduction in load. This calculation is the only demand respond type that will not forecast specific load – only actual shifting will be measured.	Shifting activities have been presented to the Commission in Docket No. 21-101, but have not yet been approved. Additional discussion in narrative.	__________
4(a)	Integration of customer loads with utility supply - Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events - for Available Load	NEW	Customers with interval data to determine the actual potential demand reduction during an event, the Company completes an analysis of actual event data collected from interval data. This analysis includes the following and may differ slightly by program: • Collection of interval data (typically five years of data is analyzed at one time); • Assign day of week and holidays to hourly data; • Update hourly load relief by customer (by contract); • Subtract firm kW to estimate potential load relief by hour; • Calculate an average 24-hour profile by month for each customer which excludes weekends, holidays and event days; • Gather 10 years of system peak system data to determine the most common peak hour by month based on frequency; and • Average the controllable load kW for each customer using the most common peak hours by month using weekdays (excluding holidays and weekends) in a given year. For customers without interval data (such as those for residential), every control season data is gathered from installed sample sites to determine load reduction capability for all Savers Switch participants. At the end of the control season we gather data for each sample point along with the corresponding weather for the control season year to use in our load management analysis.	Total Capacity Available in MN (summer 2020) 754.6 Gen. MW and 155,967 Gen. MWh.	__________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
4(a) continued			The steps to produce the forecast of potential load relief are below: • We forecast potential load relief for each sample customer by simulating interruptions for each hour given the two types of cycling strategies. The estimated potential load relief kW per customer is the difference between the observed load and the assumed cycling strategy of smart and standard switches. We estimate the potential load relief for all hours during the collection period (using the most current year data) by estimating the allowed hourly duty cycle that would be achieved by control and subtracting it from the observed kW load. The allowed duty cycle represents a simulation of the load level the AC would be controlled down to. • We then average these individual load relief estimates per hour per customer class - residential or commercial. Next, using the average sample customer load relief estimates for the group from non-interrupt days across the summer, we build linear regression models with regressing sample load relief estimates against Temperature Humidity Index (using a rolling 5 year timeframe). • From those regressions, a final model is selected based on statistical merit, to which we then apply corresponding system peaking weather conditions to derive a kW per customer load relief value.		
4(b)	Integration of customer loads with utility supply - Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events - for Actual Load Reduction Achieved	NEW	Actual load relief is determined by measurements of load during an event. We measure actual load by hour compared to the delta between the actual load and the estimated load that would have occurred without the interruption. This metric will be broken up by event for emergency and contingency events.	Total Actual Capacity called (2020) 0 Gen. MW and 1,030 Gen. MWh.	________
4(c)	Metrics that measure the effectiveness and success of items above, individually and in aggregate.	NEW	Load factor for load net of variable renewable generation. Measurement will help determine how well Xcel Energy is shaping load to integrate with most cost-effective supply including demand response, energy efficiency and DERs. The closer to one the measurement is, the more load is being shaped.	46.79% Annual Load Factor for load net of renewable generation (w/o Hydro being considered renewable) Additional discussion in narrative.	________

OUTCOME	COMMISSION-APPROVED METRIC	NEW/CURRENT/TBD REPORTING	APPROVED CALCULATION METHOD REPORT ANNUALLY	METRICS TRACKING RESULTS AND EVALUATION FOR JAN 1, 2020 - DEC 31, 2020	ASSOCIATED REPORT ATTACHMENT
Workforce and Community Development Impact					
1	Workforce plan with data relative to plant closures to analyze attrition, skill gaps, workforce impacts, etc., and plan to address impacts as result of plant closures.	NEW/TBD	No proposal at the time of the filed 10/31/19 report. See notes in 10/31/19 report re: stakeholder discussion.	Proposal in narrative.	Attachments H, I, J
Stakeholder Discussions					
1	PUBLIC DASHBOARD: Require Xcel Energy to explore and develop options to employ an online utility performance dashboard.	NEW/TBD	Report in the first annual report, include a fair estimate of costs.	Discussion in narrative.	Attachments F, G
2	DEMAND RESPONSE PERFORMANCE INCENTIVE: Develop and file a demand response incentive Commission consideration by Q1 2021.	NEW/TBD	Due March 31, 2021. work with the stakeholder group to develop.	Discussion in narrative.	Attachment C, D, E
3	EVALUATION CRITERIA AND BENCHMARKS: Work with stakeholders to file these at a later date.	NEW/TBD	The Commission will direct Xcel to work with stakeholders to develop evaluation criteria and benchmarks and file them at a later date. The Commission will wait until the appropriate step in the PIM process to decide on criteria for good versus bad performance, and establish benchmarks against which to measure Xcel's performance; however, the process of evaluating such criteria and benchmarks is likely to be complex and time-consuming, and the Commission will direct Xcel and stakeholders to begin that process.	Discussion in narrative.	

Benchmarks By Company

Investor-Owned Energy Utilities

	Base-line	95	96	97	98	99	00	01	02	03	04	05	06	07	08	09	10	11	12	13	14	15	16	17	18	19	20	21	Previous Year % Change
CenterPoint Energy	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	73	72	74	75	78	78	80	82	84	81	81	76	79	82	80	77	76	-1.3
NextEra Energy	77	77	74	69	75	74	76	73	71	73	76	74	68	73	76	76	75	78	80	80	76	77	76	75	76	77	76	76	0.0
Atmos Energy	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	75	78	78	81	83	85	83	82	77	80	80	78	78	76	-2.6
Southern Company	78	78	76	77	79	78	80	80	81	82	81	79	80	82	81	78	78	77	81	83	80	77	76	77	79	77	75	75	0.0
NiSource	NM	NM	NM	NM	NM	NM	NM	67	68	66	68	68	66	72	70	71	76	76	81	81	78	78	73	78	78	76	75	75	0.0
PPL	NM	NM	NM	NM	NM	NM	NM	80	80	80	79	80	81	81	78	79	74	79	80	80	79	78	75	77	78	73	73	74	1.4
Ameren	NM	NM	NM	NM	NM	NM	NM	78	76	77	74	75	74	57	64	68	71	71	78	74	76	76	72	74	76	75	73	73	0.0
DTE Energy	78	78	78	75	74	74	75	74	68	72	71	68	65	70	72	71	72	73	72	78	80	74	72	73	73	72	72	73	1.4
WEC Energy	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	75	75	75	76	74	73	-1.4
Consolidated Edison	77	76	74	71	69	73	71	66	74	72	68	68	68	69	66	66	66	72	71	70	69	68	71	79	78	78	75	73	-2.7
Dominion Energy	74	75	72	74	75	74	75	65	70	72	67	71	70	73	75	72	75	77	80	82	80	78	74	77	78	76	74	73	-1.4
Berkshire Hathaway Energy	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	78	79	79	79	79	82	77	75	72	76	76	74	74	73	-1.4
Public Service Enterprise Group	79	80	77	75	74	73	78	75	76	76	73	74	75	73	75	76	78	78	77	74	70	72	68	72	72	72	72	73	1.4
Xcel Energy	NM	NM	NM	NM	NM	NM	NM	65	74	73	70	68	70	71	73	76	72	74	74	76	75	76	71	73	73	74	73	72	-1.4
Sempra Energy	NM	NM	NM	NM	NM	NM	NM	67	74	77	77	79	75	80	80	80	83	81	83	80	82	79	75	78	77	75	75	72	-4.0
Exelon								66	69	71	71	71	70	68	69	70	72	73	70	74	75	69	70	71	72	73	72	72	0.0
Edison International	76	74	77	78	75	73	78	60	66	69	71	75	78	74	75	77	75	75	76	77	77	76	74	76	76	75	74	72	-2.7
Investor-Owned Energy Utilities																		**74**	**76**	**77**	**75**	**74**	**72**	**75**	**75**	**73**	**72**	**72**	**0.0**
Entergy	75	76	75	70	70	69	74	69	74	71	73	75	70	73	74	74	73	76	78	81	76	77	70	74	75	75	72	72	0.0
FirstEnergy	NM	NM	NM	NM	NM	NM	NM	72	77	76	69	71	75	76	77	74	75	78	76	75	73	79	69	73	73	72	71	72	1.4
CMS Energy	79	76	77	75	73	76	76	75	76	78	71	74	72	73	74	70	75	77	75	79	78	76	71	74	75	73	73	71	-2.7
Duke Energy	82	80	83	79	78	80	79	79	79	77	78	78	80	79	76	77	76	77	79	75	77	72	70	73	73	70	71	71	0.0
All Others	75	73	75	74	75	74	76	68	74	72	74	74	70	72	72	72	74	72	75	77	74	73	70	75	75	72	72	70	-2.8
National Grid									73	75	69	72	65	71	71	71	70	NM	NM	NM	NM	NM	71	71	73	71	70	70	0.0
American Electric Power	78	80	82	77	78	77	79	76	75	74	75	74	75	73	76	74	73	72	79	75	77	74	70	72	73	68	68	70	2.9
Eversource Energy	70	70	72	67	65	68	72	76	72	73	68	74	72	69	68	72	74	75	59	73	71	66	65	71	70	68	69	65	-5.8
PG&E	73	71	72	71	68	71	73	49	58	66	66	67	68	72	70	73	70	67	69	74	70	71	72	74	70	70	63	61	-3.2
Cinergy	NM	NM	NM	NM	NM	NM	NM	NM	NM	NM	74	75	71	#															N/A
KeySpan	NM	NM	NM	NM	NM	NM	NM	68	72	71	74	70	71	74	#														N/A
Niagara Mohawk Power	69	73	64	65	68	68	69	69	#																				N/A
PECO Energy	NM	72	70	65	66	71	72	#																					N/A

Unicom	71	68	68	62	66	62	59	#																					N/A
Central and South West	77	82	78	78	NM	76	79	#																					N/A
PacifiCorp	NM	NM	NM	NM	NM	NM	NM	72	71	76	NM	NM	#																N/A
Allegheny Energy	NM	NM	NM	NM	NM	NM	NM	79	80	76	75	74	80	79	NM	NM	NM	#											N/A
Progress Energy	NM	NM	NM	NM	NM	NM	NM	76	77	75	78	75	77	77	77	75	73	78	76	#									N/A
Pepco Holdings	NM	NM	NM	NM	NM	NM	NM	NM	NM	77	72	73	71	70	69	68	70	54	69	71	73	72	69	#					N/A
Reliant Energy	NM	NM	NM	68	73	73	75	67	74	70	68	69	69	65	72	69	72	#											N/A
Energy Future Holdings	73	74	77	70	76	74	76	71	75	74	74	72	65	63	68	72	73	NM	NM	NM	NM	NM	NM	NM	#				N/A
Iberdrola	NM	NM	NM	NM	NM	NM	NM	73	73	71	70	73	74	70	75	73	72	NM	NM	NM	NM	#							N/A
GPU	77	79	79	69	75	75	78	#																					N/A

Score tables print best in landscape.

Legend

NA	Not available
#	Company merger
†	Company defunct
NM	Not measured
^	Industry aggregated

Notes

ACSI releases industry results throughout the year and updates the national index quarterly. Baseline measurements are from the summer of 1994.

**The limited-service restaurant industry was not measured in 2004 due to a change in the quarterly measurement system that was in place at that time.
***Measurement for the Internet travel industry was moved from the fourth quarter of 2013 to the first quarter of 2014.

The "All Others" score for an industry represents the remainder of the total industry market share, less the market shares of the ACSI-measured companies. It is an aggregate of a representative number of customer interviews from each of potentially hundreds of smaller companies within the industry. Individual company scores within the "All Others" category cannot be derived without additional data collection (see "ACSI Products and Services," or to generate your own ACSI score using the ACSI methodology, see "ACSI Monitor^{SM}").

Attachment C

Summary
Demand Response Incentive Mechanism
Stakeholder Meeting No. 1

October 6, 2020

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE COMMISSION INVESTIGATION TO IDENTIFY AND DEVELOP PERFORMANCE METRICS AND POTENTIALLY, INCENTIVES FOR XCEL ENERGY'S ELECTRIC UTILITY OPERATIONS	DOCKET NO. E002/CI-17-401 DEMAND RESPONSE INCENTIVE MECHANISM SUMMARY – STAKEHOLDER MEETING NO. 1

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (the Company), submits to the Minnesota Public Utilities Commission (Commission) this Meeting Summary Report in accordance with the Commission's April 16, 2020 ORDER ESTABLISHING METHODOLOGIES AND REPORTING SCHEDULES in the above-noted docket.

Ordering Paragraph No. 1.f. instructed Xcel Energy to:

> *In consultation with the Department and interested stakeholders, develop and file a demand response financial incentive for Commission consideration by the end of the first quarter of 2021.*

On September 15, 2020, the Company served notice of three stakeholder meetings to discuss the development of a demand response performance incentive mechanism. The overall intent for the meetings is to comply with the Commission's Order, follow the same transparent and collaborative stakeholder process utilized in the Performance Based Ratemaking (PBR) metrics development in the present proceeding, and provide information and mechanism tools for stakeholders' review and analysis towards making a demand response financial incentive recommendation to the Commission.

While not required as part of the Commission's Order, we provide this summary of the first online stakeholder meeting conducted October 6, 2020 for transparency of process. The goals of this first workshop were to provide attendees a review of the objectives and history of the Commission's PBR proceeding that was an outgrowth of Xcel Energy's multi-year rate plan in Docket No. E002/GR-15-826 and to introduce incentive mechanism options related to demand response.

The format of the meeting was via online Teams.

Participants included:

Participant	Organization	Participant	Organization
Brian Edstrom	Citizens Utility Board	Chris Villarreal	RStreet Institute
Tricia DeBleekere	Dept of Comm	Grey Staples	Mendota Group
John Kundert	Dept of Comm	Mike Bull	Ctr for Energy & Env
Brian Millberg	City of Minneapolis	Kelly Martone	Public Utilities Comm
Annie Levenson Falk	Citizens Utility Board	Greg Miller	Dakota Electric
Stacy Miller	City of Minneapolis	Sean Stalpes	Dept of Comm
Will Kenworthy	Vote Solar	Peter Scholtz	Office of Attorney Gen
Audrey Partridge	Ctr for Energy & Env	Thor Bjork	Xcel Energy
Brian Doyle	Xcel Energy	Shawn White	Xcel Energy
Jessie Peterson	Xcel Energy	Jeremy Petersen	Xcel Energy
Crystal Gottschalk	Xcel Energy	Bridget Dockter	Xcel Energy

We provided a PowerPoint presentation to attendees which is included as Attachment A to this Report.

The Company will host subsequent meetings on October 20 and November 10 and provide a similar summary for each.

The remainder of this Report is organized as follows:

- Section I discusses the objectives and history provided attendees to ground them in the instant docket;
- Section II describes our current demand response regulatory requirements and high-level stakeholder discussion;
- Section III addresses the demand response measures we are developing and introduced to stakeholders for feedback as well as a high-level stakeholder discussion;
- Section IV describes the demand response incentive mechanisms the Company has under consideration and high-level stakeholder discussion; and
- Section V discusses our next meeting and intent to file the demand incentive mechanism yet in 2020.

I. OBJECTIVES AND HISTORY OF PBR PROCEEDING

To ground attendees in the context of the current meeting, we reviewed the Commission's April 16, 2020 Order and meeting objective. Additionally, we provided a brief historical background of the current docket and critical approval dates, including a review of the Commission's approved Outcomes and the Performance Incentive Mechanism (PIM) process.

Q&A
No clarifying questions were asked by attending parties at this time.

II. DEMAND RESPONSE BACKGROUND

The Company reviewed current Commission Orders for demand response in the PBR docket to report annually on SHED efforts and when available in the future, SHAPE and SHIFT. We also reviewed the Commission's Order[1] dated January 11, 2017 to add an additional 400 MW of demand response to our system by 2023.

Q&A

1. Is there a reason we were testing demand response opportunities in Colorado versus Minnesota?
   Response: Colorado rules currently allow for load shifting activities to occur in their DSM programs, making it more conducive for some pilots; however, we have piloted demand response programs in MN where we can.

III. DEMAND RESPONSE INCENTIVE MEASURES

At this initial meeting, we reviewed four demand response measures being considered for the Miscellaneous Filing: Peak Flex rate, vehicle to grid (school bus), commercial load sifting and residential load shifting.

---

[1] *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, Docket No, E002/RP-15-21 (January 11, 2017).

Demand Response Measures

Reviewing four rate structures to allow customer flexibility and options

Peak Flex Rate	Summer Only Option – Interruptible Rate Year-Round Option – Interruptible Rate Buy-Thru Event
Vehicle to Grid (School Bus)	Pilot Rate for non-peak charging
Commercial Load Shifting	Reverse Demand Response Scheduled EV charging Thermal Storage Commercial Building Systems
Residential Load Shifting	Smart Water Heating Reverse Demand Response Scheduled EV charging

<u>Q&A</u>

2. What elements of our proposal rely on technology provided by AMI?
<u>Response</u>: Currently, none, but load shifting measures will incorporate AMI in the future, and we continue to review opportunities with that in mind.

3. Any sense of kW or kWh projecting for electric vehicle (EV) charging--this looks to be minimal?
<u>Response:</u> Correct, with EV charging, it is more around when the vehicle is being charged on the grid, not how much.

4. Who is getting paid for the negative pricing associated with some of these measures, and will that compensation be shared with customers?
<u>Response</u>: Yes. We plan to incentivize participating customers.

5. To what extent are we considering bidding into the MISO market?
<u>Response</u>: We are planning to be responsive to the MISO market verses bidding into it with these particular products.

6. How will we be thinking about avoided carbon in our plan?
<u>Response</u>: We will continue to work on this to become more granular. They require hourly emissions factors because they save smaller amounts of energy.

7. Why are we basing our DR cost effectiveness on a Ratepayer Impact Measure (RIM) test?
<u>Response</u>: We are using the RIM test because the Commission discussion came out of our Integrated Resource Plan (IRP), and that Plan uses the RIM test to gauge cost effectiveness. Stakeholder commented that the state of California has discontinued using the RIM test as the cost-effectiveness gauge.

8. Why is the RIM test appropriate for demand response but not for energy efficiency?
   Response: There are weaknesses in the societal test, so this is not the best test for demand response. Using the societal test, it is difficult to determine the cost to customers, making that test more problematic. We will discuss more in meeting No. 2.

9. Have we looked at the new National Standard Practices Manual to see what their recommendations are for cost-effectiveness testing for demand response?
   Response: Not closely, but we certainly will.

IV. DEMAND RESPONSE INCENTIVE MECHANISM

The Company has been developing two demand response incentive mechanisms that were shared with the group. The first is a shared savings mechanism, similar to that of the Conservation Improvement Program (CIP). This mechanism splits the net benefits between customers (90%) and the utility (10%) and is more appropriate for traditional energy efficiency, because the net benefit will cover the cost of lost sales. Because DR net benefit is based on price signals, it will not cover the lost sales. The second is a capitalization mechanism that is more appropriate for demand response because it is more in line with the lost-opportunity disincentive of the return on the capital assets not built as a result of the DR achievements. The Company has identified this as the main disincentive in pursuing DR programs.

Q&A

10. Will the mechanism results use the RIM test in the shared savings mechanism?
    Response: It will use both the RIM and the Utility cost test (UCT).

11. In the shared savings mechanism, are the incentives or ongoing bill credits being paid to customers?
    Response: Yes.

12. Would Xcel be capitalizing the expenses to earn a rate of return?
    Response: Under the capitalization PIM, yes, but we have not arrived at a preferred option yet. We can show the capitalization options and the effect of amortization periods as examples, and calculate the total incentive for each in meeting No. 2.

13. Will the price signals be revenue neutral? Often you solve for that.
    Response: That is correct, but there will be another mechanism to make sure we are on par with the benefits of the program using the RIM test, and that is the program cost we would seek to recover.

14. Interested in the capitalization approach but want to see the math. Have other jurisdictions done the capitalization approach in this way?
Response: We do have a percent of spend mechanism in South Dakota but will also dig into other states across the country that may use this.

    Additional not discussed during meeting: We also commissioned a study that identified a couple of states with existing capitalization mechanisms. we will discuss these during meeting No. 2.

15. Other than storage, how can commercial customers really modify their usage? Incentives need to be pretty big to engage customers to take on possible risks. Provide examples in our next discussion.
Response: We will provide examples in meeting No. 2.

16. Referencing how often the existing demand response programs were dispatched – does Xcel Energy have any updated information? How will Xcel Energy dispatch demand response versus just providing capacity credits?
Response: There is value in these programs around the operational and capacity value when we hold these in reserve. You will see a modest filing to hedge for the future and make the demand response more dynamic.

17. Need to understand how well the demand response is being used and reward the utility for that.

V. NEXT STEPS

The second demand response stakeholder meeting scheduled for October 20, 2020 will largely focus on further discussion of our proposed incentive mechanism. Additionally, stakeholders have been asked to bring forth any ideas, measures or mechanisms they would like to discuss with the group.

A Miscellaneous Filing addressing the demand response financial incentive mechanism proposal will be submitted to the Commission no earlier than November 30, 2020 for an anticipated summer 2021 launch. This filing serves to satisfy two Commission orders and support the achievement of a third order. The first is the anticipated Order resulting from the September 17, 2020 Hearing in Docket No. E002/M-20-421 where the Company will be ordered to submit their demand response programs as part of a Miscellaneous Filing versus including these efforts as part of an ongoing rate plan.

The second is the Commission's April 16, 2020 Order in the PBR docket (Docket No. E002/CI-17-401) requiring the Company to propose an incentive mechanism for demand response activities. The third is the Commission's January 11, 2017 Order requiring the Company to acquire 400 MW of additional DR resources (Docket No. E002/RP-15-21). The Miscellaneous Filing will include products and measures that align with state, societal, customer and company objectives designed to provide customers with flexibility and the opportunity to increase sustainability.

CONCLUSION

Thank you for this opportunity to introduce and develop a proposal for a demand response financial incentive, in conjunction with stakeholder input. We look forward to further discussions.

Dated: October 15, 2020

Northern States Power Company

PERFORMANCE BASED RATEMAKING DEMAND RESPONSE INCENTIVE MECHANISM

Stakeholder Meeting #1

October 6, 2020

Xcel Energy®

Agenda

Introductions

Stakeholder Meeting Objectives

1. Follow Commission Order: *Establishing Methodologies and Reporting Schedules in Docket No. E002/CI-17-401 and dated April 16, 2020, Xcel Energy, in consultation with the Department and interested stakeholders will develop and file a Demand Response financial incentive for Commission consideration by the end of the first quarter of 2021.*

2. Follow the same transparent and collaborative stakeholder process utilized in the Performance Based Ratemaking (PBR) metric development.

3. Provide information and mechanism tools for review and analysis by stakeholders for further discussion in meeting #2.

Stakeholder Meeting Process

October 6

- Review Objectives, History, Introduce Incentive Mechanism Options
- Summary report filed with Public Utilities Commission

October 20

- Stakeholder feedback & opportunity to bring forth new ideas
- Summary report filed with Public Utilities Commission

November 10

- Determination of stakeholder positions, consensus building where possible
- Summary report filed with Public Utilities Commission

HISTORY

How did we get here?

Where is our baseline?

Commission Proceedings

2015 – Commission opened PBR proceeding as an outgrowth of Xcel Energy's electric rate case, Docket No. E002/GR-15-826

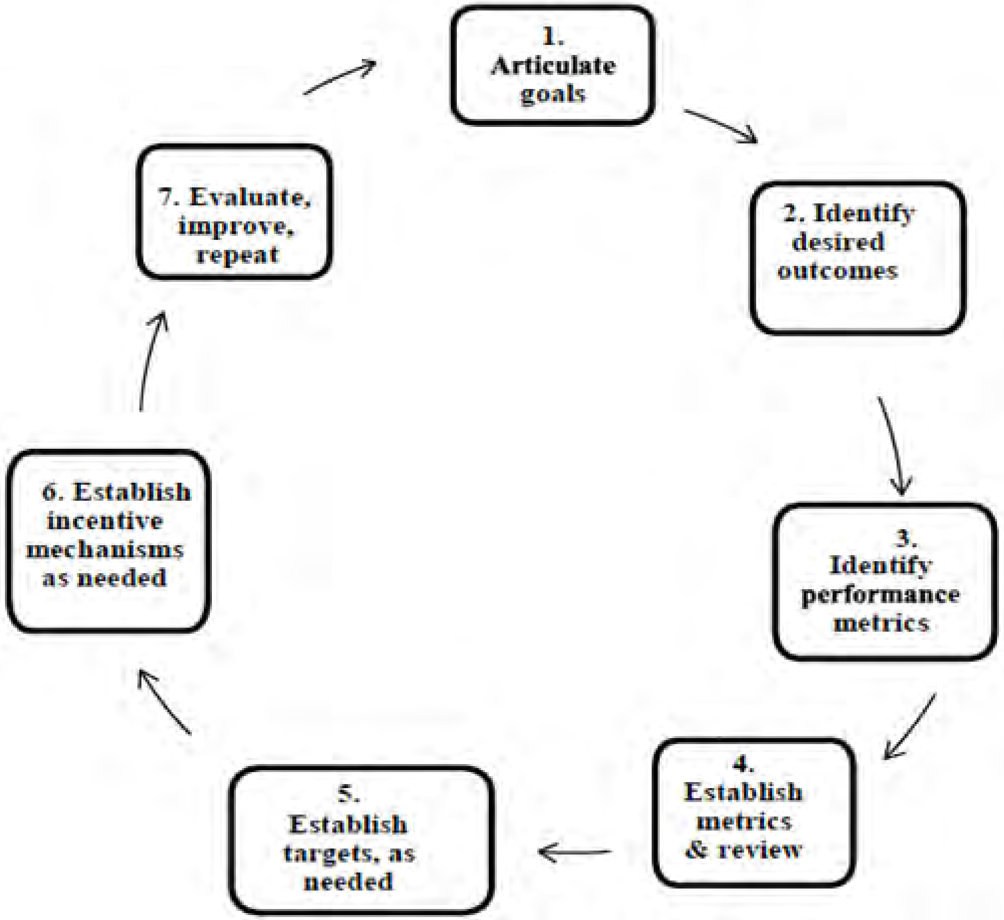
2017 – 2016-2030 Integrated Resource Plan Commission Order to increase demand response resources by 400 MW by 2023, Docket No. E002/RP-15-21

2017 - Commission solicited input on topics related to performance-based utility regulation, Docket No.E002/CI-17-401

2019 - Commission approved five performance outcomes by which specific metrics would fall under: Affordability, Reliability, Customer Service Quality, Environmental Performance, **and Cost-Effectively Aligning Generation to Load.** Docket No. E002/CI-17-401

2019 - Commission approved a Performance Incentive Mechanism Process (PIM), Docket No. E002/CI-17-401

Performance Incentive Mechanism



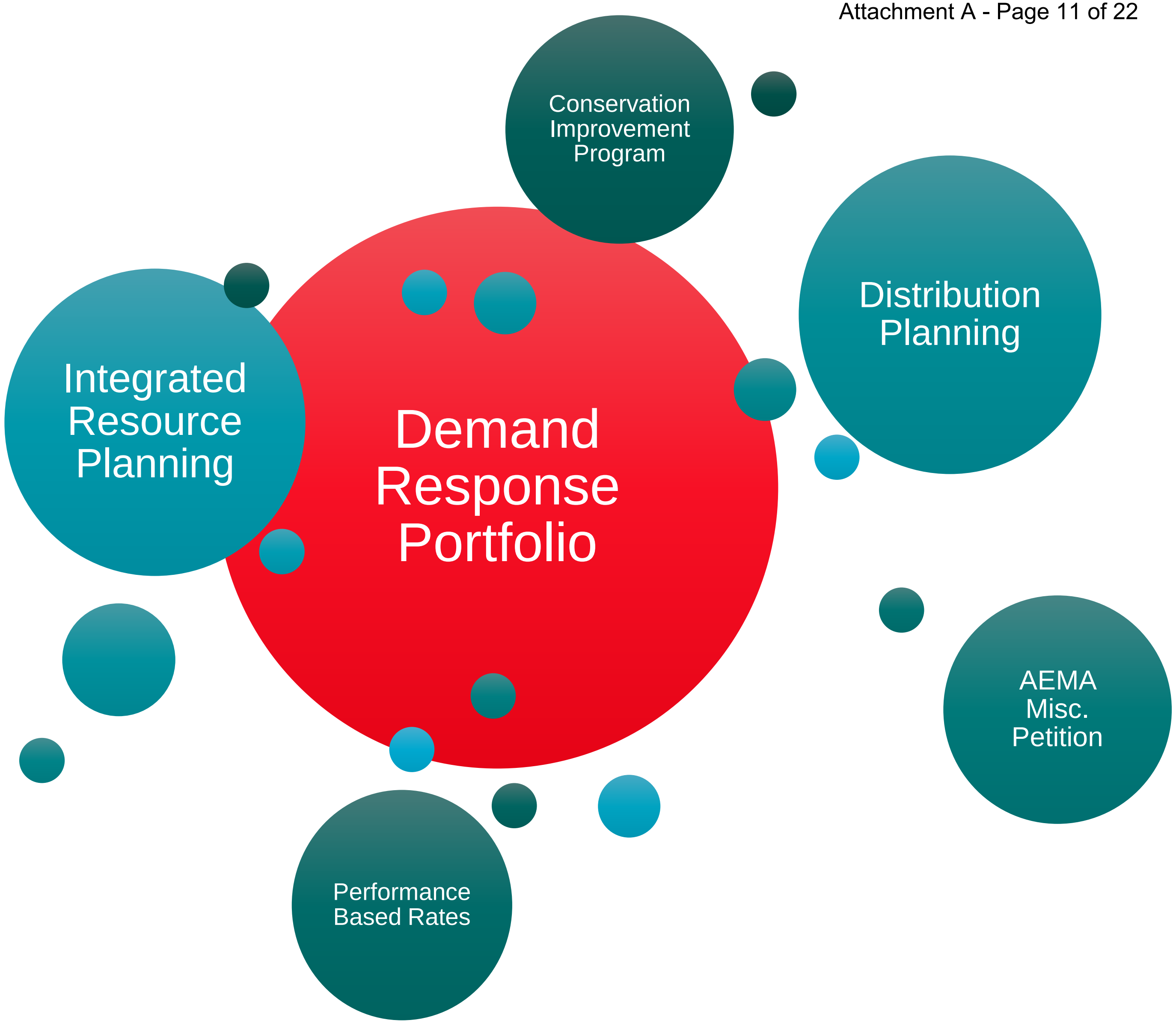
Performance Based Ratemaking Process & Next Steps

- Multiple stakeholder meetings to develop metrics
- Commission Order to report annually April 30 on 28 metrics approved in its April 16, 2020 Order
- Explore options for an online performance dashboard with interested stakeholders and file with annual report (meeting notices forthcoming)
- Department and stakeholder consultation in development of demand response financial incentive by Q1 2021

DEMAND RESPONSE

Adjusting the Portfolio

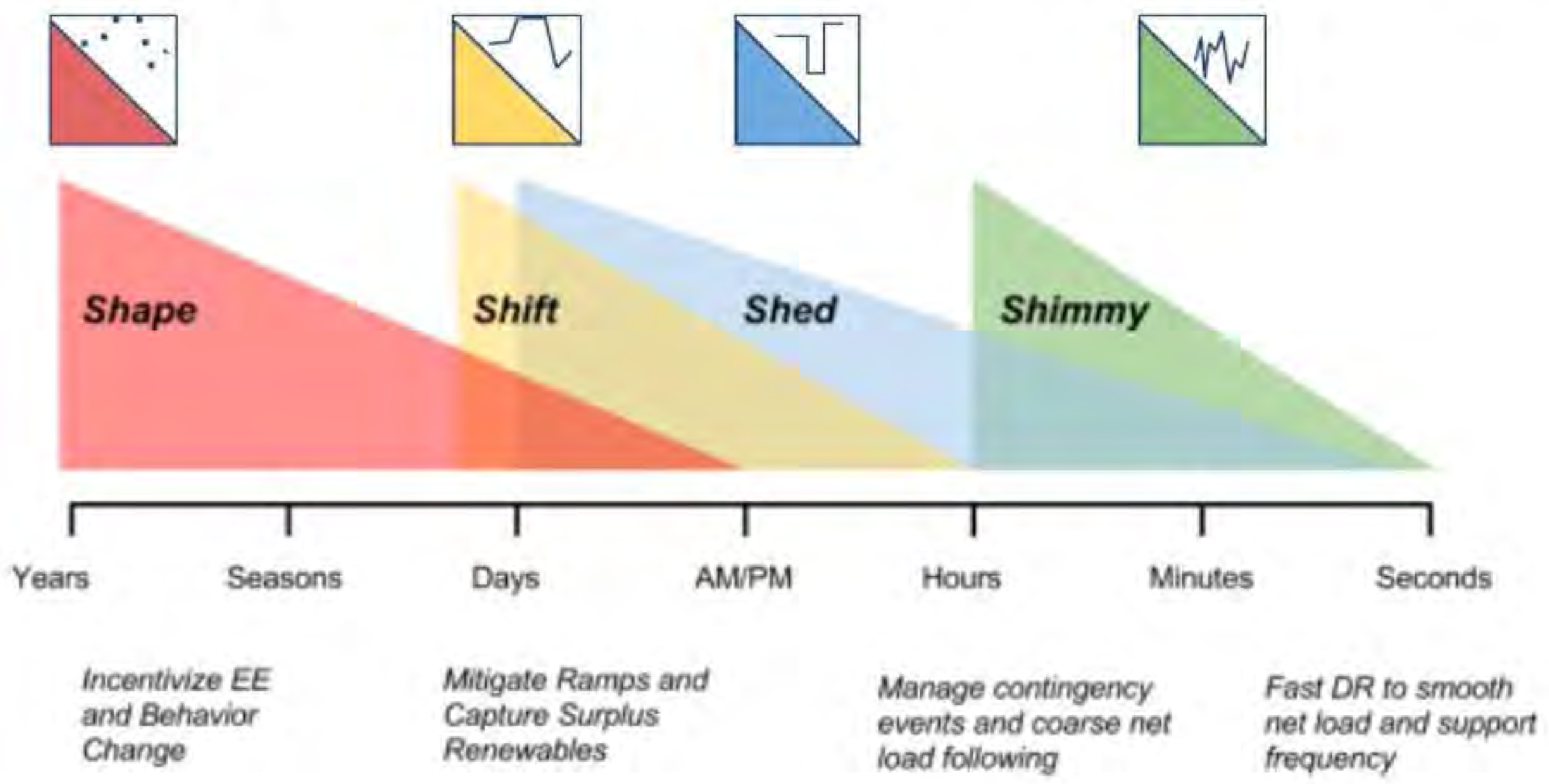
- Customers are looking for flexibility and opportunity to reduce their energy bills and increase sustainability (CO2)
- We are looking to provide a portfolio that creates value for society, the utility and customers
- 3 Commission Orders:
  - 400 MW of additional demand response resources (by 2023)
  - Ordered to file as Misc. Filing
  - Performance Based Metrics



What will Demand Response Look Like?

Moving from traditional demand response to non-traditional demand response or demand management (managing energy by shifting load)

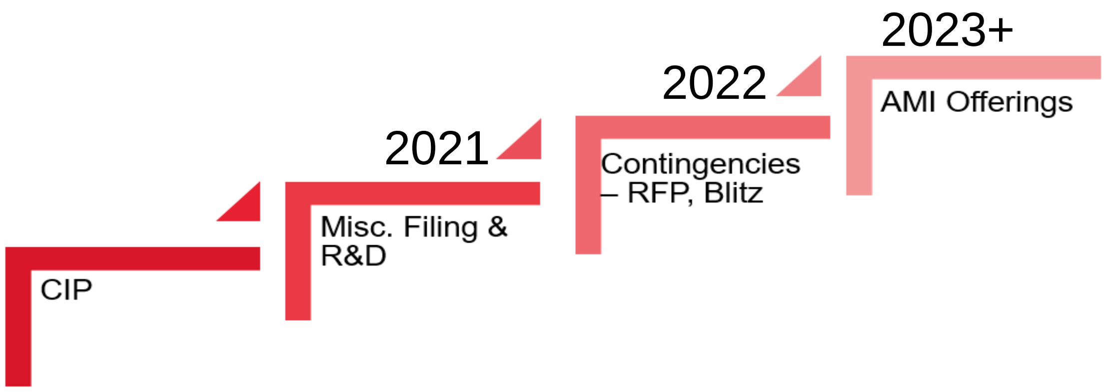
Figure 1: DR Service Across Timescales to Meet Future Grid Needs[16]



PBR Metrics

Metric	Existing/Future
(1) capacity available (MW & MWh) and (2) amount called (MW, MWh per year).	Existing
Amount of demand response that SHAPES customer load profiles through price response, time varying rates, or behavior campaigns	Future
Amount of demand response that SHIFTS energy consumptions from times of high demand to times when there is a surplus of renewable generation	Future
Amount of demand response that SHEDS loads that can be curtailed to provide peak capacity and supports the system in contingency events	Existing
Load factor for load net of variable renewable generation	Future

2017 – 2019 Progress Towards 400 MW



  - Peak Partner Rewards
  - Expanded Smart Thermostat (Optimization) program
  - Smart Thermostats in South Dakota & Wisconsin
  - Limited Smart Water Heating
- Piloting several opportunities (many in Colorado Service Territory)

Next Steps Forward – Misc. Filing

  - Providing customers flexibility and the opportunity to increase sustainability
  - These will look different from our traditional programs
- Cost and Beneficial analysis
- Research and Development Options
- Cost Recovery Mechanism
- Incentive Mechanism

Demand Response Measures

Peak Flex Rate	Summer Only Option – Interruptible Rate Year-Round Option – Interruptible Rate Buy-Thru Event
Vehicle to Grid (School Bus)	Pilot Rate for non-peak charging
Commercial Load Shifting	Reverse Demand Response Scheduled EV charging Thermal Storage Commercial Building Systems
Residential Load Shifting	Smart Water Heating Reverse Demand Response Scheduled EV charging

Additional Products/Next Steps

INCENTIVE MECHANISM MODELING

Incentive models for DR achievement through various existing and potential mechanisms

Demand Response Disincentives/Indirect Incentives

Incentives:

- Helps customers to keep bills low
- Increases utilization of renewable generation

Disincentives:

- Lost Opportunity for investment and return of new Generation Capacity
- Sales reduction may exceed cost savings resulting in lost earnings to utility
- Revenue without Return – Program costs collected from customers to run programs that do not provide earnings opportunities

Incentive Mechanisms Considered for Misc. Filing

Shared Savings Mechanism

- Current CIP Mechanism – Splits net benefits between customers (90%) and the utility (10%)
- Appropriate for Energy Efficiency Programs
  - Program costs incentivize purchase of long-life cost-effective Energy Efficiency measures
  - Significant net benefits in bill savings to participating customers
  - Incentivizes utility to maximize bill savings by awarding fraction of benefits to utility
- Demand Response
  - Program costs are price signals to participating customers to change load
    - Price signals on par with costs of utility generation
  - Net Benefits are reduced prices to participating customers = program costs

Capitalization Mechanism

- Rate of return on costs spent – directly addresses lost opportunity disincentive
- Fraction of costs award shares benefits with customers
- More appropriate for Demand Response

Next Steps

Next meeting October 20

Discuss the technologies and incentive mechanisms brought forth today

Of those technologies, any specific areas you would like to focus on at the next meeting?

Additional ideas? Technologies or incentive mechanisms to explore?


Xcel Energy®

Attachment D

Summary
Demand Response Incentive Mechanism
Stakeholder Meeting No. 2

October 20, 2020

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE COMMISSION INVESTIGATION TO IDENTIFY AND DEVELOP PERFORMANCE METRICS AND POTENTIALLY, INCENTIVES FOR XCEL ENERGY'S ELECTRIC UTILITY OPERATIONS

DOCKET NO. E002/CI-17-401

DEMAND RESPONSE
INCENTIVE MECHANISM

SUMMARY – STAKEHOLDER MEETING NO. 2

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (the Company), submits to the Minnesota Public Utilities Commission (Commission) this Meeting Summary Report (Report) in accordance with the Commission's April 16, 2020 ORDER ESTABLISHING METHODOLOGIES AND REPORTING SCHEDULES in the above-noted docket.

Ordering Paragraph No. 1.f. instructed Xcel Energy to:

> *In consultation with the Department and interested stakeholders, develop and file a demand response financial incentive for Commission consideration by the end of the first quarter of 2021.*

On September 15, 2020, the Company served notice of three stakeholder meetings to discuss the development of a demand response performance incentive mechanism. The overall intent for the meetings is to comply with the Commission's Order, follow the same transparent and collaborative stakeholder process utilized in the Performance Based Ratemaking (PBR) metrics development in the present proceeding, and provide information and mechanism tools for stakeholders' review and analysis towards developing a demand response financial incentive recommendation to the Commission.

While not required as part of the Commission's Order, we provide this summary of the second online stakeholder meeting conducted via Teams platform on October 20, 2020 for transparency of process. General stakeholder questions and Company responses are included in this Report to document the direction of the discussion. The goal of the second workshop was to engage deeper discussion and provide attendees with additional detail behind the proposed incentive mechanism(s), including the cost/benefit analysis tests we recommend as appropriate in determining cost-effectiveness and how that relates to a financial incentive for demand response.

Participants included:

Participant	Organization	Participant	Organization
Brian Edstrom	Citizens Utility Board	Isabel Ricker	Fresh Energy
Tricia DeBleekere	Dept of Comm	Grey Staples	Mendota Group
John Kundert	Dept of Comm	Allen Gleckner	Fresh Energy
Brian Millberg	City of Minneapolis	Kelly Martone	Public Utilities Comm
Mustafa Adam	Xcel Energy	PJ Martin	Xcel Energy
Chris Davis	Dept of Comm	Sean Stalpes	Dept of Comm
Will Kenworthy	Vote Solar	Peter Scholtz & Brian Lebens	Office of Attorney General
Audrey Partridge	Ctr for Energy & Env	Thor Bjork	Xcel Energy
Brian Doyle	Xcel Energy	Shawn White	Xcel Energy
Jessie Peterson	Xcel Energy	Jeremy Petersen	Xcel Energy
Crystal Gottschalk	Xcel Energy	Bridget Dockter	Xcel Energy

We provided a PowerPoint presentation to attendees that is included as Attachment A to this Report.

The Company will host a final stakeholder meeting on November 10 and provide a similar summary.

The remainder of this Report is organized as follows:

- Section I describes the meeting objectives;
- Section II discusses our proposed and alternative demand response incentive mechanisms and recommended test to use for cost/benefit analysis; and
- Section III discusses our next meeting and intent to file the demand incentive mechanism yet in 2020.

I. MEETING OBJECTIVES

In meeting No. 1, we provided a historical look at the PBR process in this docket. In meeting No. 2, we again reviewed the Commissions April 16, 2020 Order, the objectives to maintain the same transparent and collaborative process as was used in the initial PBR development, intent to delve deeper into the incentive mechanism discussion, and our desire to open the conversation to stakeholder ideas for demand response measures and or incentive mechanisms.

Q&A

No clarifying questions were asked by attending parties at this time.

II. INCENTIVE MECHANISM MODELS AND COST/BENEFIT ANALYSIS

The Company provided additional detail on how each incentive mechanism might work and the differences between them. Capitalization of investments with a rate of return offers simplicity, transparency and consistency with the treatment of supply side resources. A shared savings mechanism is more aligned with traditional Conservation Improvement Program (CIP) incentives and more clearly awards the Company for performance on cost-effective demand side programs. Additionally, we provided supporting data detailing what costs are included in each of the cost/benefit tests, especially the Rate Impact Measurement (RIM) test, as requested by participants. A summary of the meeting discussion is provided below in question and answer format.

Q&A

1. Is Xcel Energy proposing the incentive mechanism kick in from day one or after the Ordered incremental 400 MW is fulfilled?
   Response: That is still under discussion internally.

2. It would be helpful if you could provide other places in the country that are using the capitalization model.
   Response: Xcel Energy to follow-up for discussion at the next meeting.

3. Will the RIM test include bill credit plus any incentive the Company is receiving?
   Response: We may consider that. The National Standards & Practices Manual updated in 2020 does recommend this.[1]

4. What about the proposed incentive ensures this is done cost-effectively? This appears to be going in the wrong direction. Why not use a shared savings approach to do this for the least cost possible?
   Response: We need controls for cost-effectiveness and prudency. Do you have suggestions or ideas?

---

[1] https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf.

5. How is demand response integrated and modeled in the Resource Plan?
   Response: Demand response was modeled as a supply side resource in the most recent IRP. The Company used the June 2019 Brattle Study to derive three separate "bundles" of demand response resources based on aggregated MWs of demand reduction potential as well as anticipated costs. The first bundle included approximately 400 MW of incremental demand response by 2023 and was included in all scenarios, as it represents the 400 MW of demand response that was ordered by the Commission in the last Resource Plan. The second and third bundles were higher-cost options that were allowed to compete with other resources in the expansion plan optimizations, but ultimately did not prove as cost effective in the Resource Plan modeling and consequently were not recommended for inclusion in the Preferred Plan. For reference and additional context, see Attachment B to this Report, which is a copy of the June 2019 Brattle Study included with our Resource Plan as Appendix G2: Study: Potential for Load Flexibility at NSP.[2]

6. Xcel Energy brings up an important point about the difference between energy efficiency modeling and demand response modeling: Demand Side Management (DSM) is cumulative, whereas demand response needs to be looked at annually. Appendix A to the updated Standards and Practices Manual addresses rate impacts and the RIM test where the use of the RIM test is discouraged. What is Xcel Energy's take on that?
   Response: We agree that for energy efficiency, you should not use the RIM test. The primary cost for demand response is the rate treatment to customers. Without the RIM test, we are not sure what would inform customer bill credits and system benefits.

7. What is the source of the avoided costs used?
   Response: The Resource Plan is the source of the avoided costs we are using.

8. I would like to see the numbers behind the curve of the amortization model shown on slide 7 for the November filing.
   Response: We will provide the most current information available at the November 10 meeting and provide final data in the Miscellaneous filing.

9. How do you set the rebate levels with the capitalization method? As a customer, I would want them as high as possible to offset equipment costs.
   Response: We are trying to balance the Order for acquiring an incremental 400 MW at the lowest cost. We will need to consider incentive levels for government and commercial customers.

---

[2] Docket No. E002/RP-19-368; The Potential for Load Flexibility in Xcel Energy's Northern States Power Service Territory.

10. Is the demand response financial incentive proposal geared towards the 400 MW Order, or is it meeting other needs?
    Response: We see a longer-term vision for demand response that will include the most efficient management of an advanced grid and adaptation to low carbon generation. An incentive would help to remove the inherent disincentives to achieving 400 MWs of incremental load while encouraging us to invest in additional capabilities that go beyond that target.

11. Is there talk about re-imagining the existing portfolio for other reasons – to enhance other benefits it might offer?
    Response: Yes, we anticipate economic savings for the operation of demand response that, while not significant in costs now will grow as the system evolves. These values may include renewable ramping, voltage regulation and geo-targeted load balancing.

12. In the next meeting, please review the cost treatment – what will we propose to capitalize?
    Response: We will provide in the next meeting.

Additional Comments/Recommendations
Attendees asked the PowerPoint presentation be provided a few days ahead of the meeting to allow time to digest materials and develop questions and/or recommendations.

Response: We committed to providing materials 48 hours before the third meeting.

III. Next Steps

The third demand response stakeholder meeting scheduled for November 10, 2020 is intended to continue focused discussion of our proposed incentive mechanism and answer stakeholder questions. At this meeting, we will attempt to determine and subsequently report stakeholder level of consensus/no-consensus and agreement/no-agreement on our proposed mechanism.

A Miscellaneous filing addressing the demand response financial incentive mechanism proposal will be submitted to the Commission no earlier than November 30, 2020 for an anticipated summer 2021 launch. This filing serves to satisfy two Commission orders and support the achievement of a third order. The first is the anticipated order resulting from the September 17, 2020 Hearing in Docket No. E002/M-20-421 where the Company will be ordered to submit their demand response programs as part of a Miscellaneous Filing versus including these efforts as part of an ongoing rate plan. The second is the Commission's Order in the PBR docket (Docket No. E002/CI-17-401) requiring the Company to propose an incentive mechanism for demand response activities. The third is the Commission's January 20, 2017 Order requiring the Company to acquire 400 MW of additional DR resources (Docket No. E002/RP-15-21). The filing will include products and measures that align with state, societal, customer and company objectives, designed to provide customers with flexibility and the opportunity to increase sustainability.

CONCLUSION

Thank you for this opportunity to introduce and develop a proposal for a demand response financial incentive. We appreciate the time stakeholders have taken to engage in these discussions as they help to shape the proposal.

Dated: October 26, 2020

Northern States Power Company

PERFORMANCE BASED RATEMAKING DEMAND RESPONSE INCENTIVE MECHANISM

Stakeholder Meeting #2

October 20, 2020

Xcel Energy®

Agenda

Introductions

Stakeholder Meeting Objectives

1. Follow Commission Order: *Establishing Methodologies and Reporting Schedules in Docket No. E002/CI-17-401 and dated April 16, 2020, Xcel Energy, in consultation with the Department and interested stakeholders will develop and file a Demand Response financial incentive for Commission consideration by the end of the first quarter of 2021.*

2. Follow the same transparent and collaborative stakeholder process utilized in the Performance Based Ratemaking (PBR) metric development.

3. In depth discussion of measures and incentive mechanism presented to the stakeholder group in meeting #1.

4. Introduction of new measures and/or mechanism options for discussion by stakeholders.

Stakeholder Meeting Process

October 6

- Review Objectives, History, Introduce Incentive Mechanism Options
- Summary report filed with Public Utilities Commission

October 20

- Stakeholder feedback & opportunity to bring forth new ideas
- Summary report filed with Public Utilities Commission

November 10

- Determination of stakeholder positions, consensus building where possible
- Summary report filed with Public Utilities Commission

INCENTIVE MECHANISM MODELING

Incentive models for demand response achievement through existing and potential mechanisms

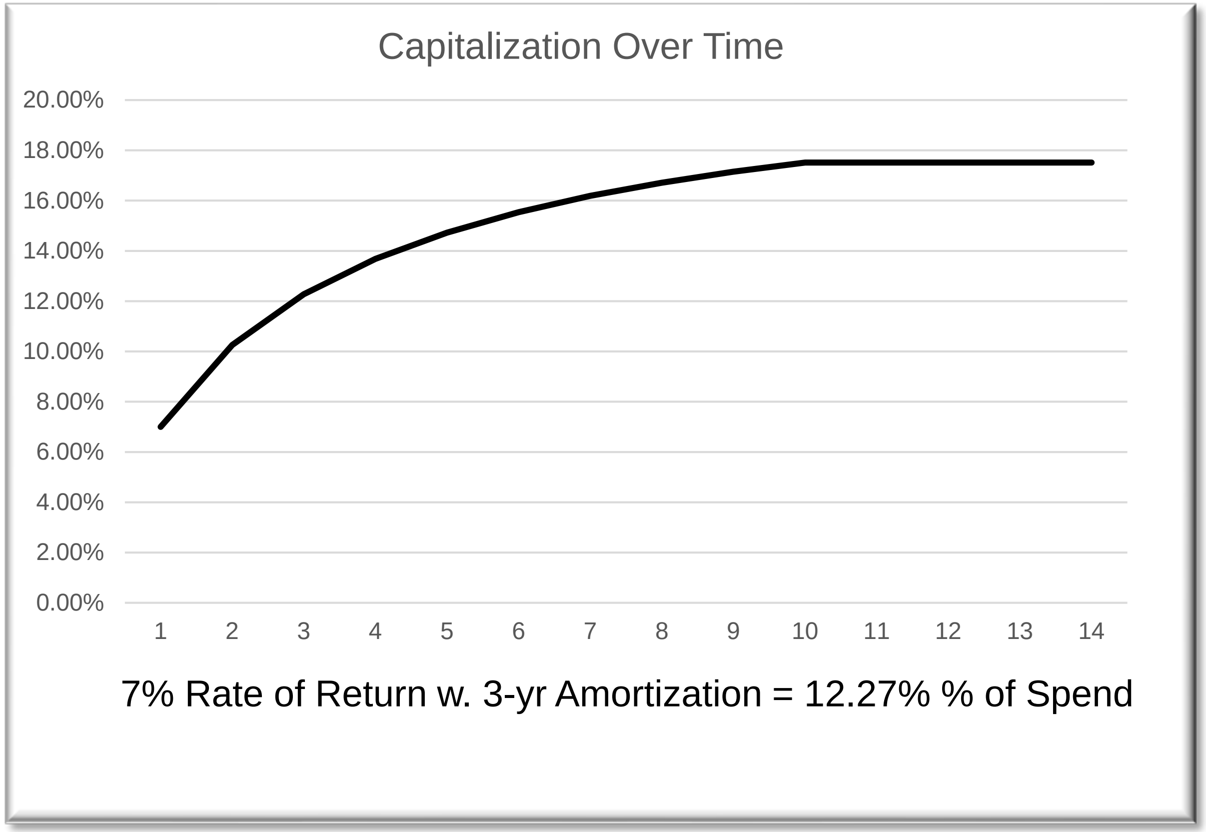
Capitalization Mechanism

Mimics Treatment of Program Costs as Capitalized Costs

- Based on Amortization Period (Years) and Rate of Return
- Costs are amortized over life of "asset"
  - 7% Rate of return w/3-year amortization
  - Small incentive initially that builds as Company efforts continue then levels as initial investments mature.

Challenges

- Incentive Deferred and Accumulates as Amortization Period Increases
- Future Return Discounted by Weighted Average Cost of Capital (~7%) to calculate NPV



Shared Savings Mechanism

- Current CIP incentive model – 10% of utility cost test net benefits
  - Customers retain 90% of net benefits
- Acceptable mechanism at the scale of CIP
  - CIP achieved 120 MW demand reduction in 2019, similar every year
- Pursuit of more aggressive DR will challenge cost effectiveness and therefore benefits
  - This will be true of CIP over time as well
  - Company has requested working group to evaluate new incentive models for CIP

Recommendation - Capitalization

- More likely to approximate lost opportunity cost of building infrastructure and therefore result in Company support
- Encourages the Company to pursue all cost-effective demand response
- Less complex and more transparent
- Open to feedback on how to ensure customers (participants and non-participants) benefit and are protected by the programs

COST-BENEFIT ANALYSIS

CIP Cost-Benefit Tests

Cost-Benefit Analysis Screening

- Total Resource Cost Test / Societal Test
  - Ensures measures within programs are cost-effective when all costs and benefits are included
  - Rebates to Participants are a pass-through cost (treated as benefit and cost)
- Participant Test
  - Ensures programs are cost-effective to individual participants
  - Sets cost-effective Rebate level

Incentive Mechanism Net Benefits

- Utility Test (Revenue Requirements Test)
  - Incentivizes Utilities to maximize System Benefits (Revenue Requirements charged to customer base) and minimize program costs (recovery from customer base)
  - Measures cost savings to customer base
  - Shared Savings Mechanism splits savings between customer base (90%) and utility (10%)

CIP Cost Benefit Test Results (Example)

RESIDENTIAL HEATING AND COOLING 2021 ELECTRIC GOAL

2021 Net Present Cost Benefit Summary Analysis For All Participants

	Participant Test ($Total)	Utility Test ($Total)	Rate Impact Test ($Total)	Total Resource Test ($Total)	Societal Test ($Total)
Benefits					
Avoided Revenue Requirements					
Generation	N/A	$6,624,556	$6,624,556	$6,624,556	$7,906,850
T & D	N/A	$1,177,706	$1,177,706	$1,177,706	$1,409,572
Marginal Energy	N/A	$2,938,301	$2,938,301	$2,938,301	$3,643,975
Environmental Externality	N/A	N/A	N/A	N/A	$477,259
Subtotal	N/A	$10,740,563	$10,740,563	$10,740,563	$13,437,656
Participant Benefits					
Bill Reduction - Electric	$16,747,830	N/A	N/A	N/A	N/A
Rebates from Xcel Energy	$3,939,431	N/A	N/A	$3,939,431	$3,939,431
Incremental Capital Savings	$320,890	N/A	N/A	$320,890	$299,713
Incremental O&M Savings	$0	N/A	N/A	$0	$0
Subtotal	$21,008,151	N/A	N/A	$4,260,321	$4,239,144
Total Benefits	$21,008,151	$10,740,563	$10,740,563	$15,000,884	$17,676,800
Costs					
Utility Project Costs					
Customer Services	N/A	$3,750	$3,750	$3,750	$3,750
Project Administration	N/A	$628,216	$628,216	$628,216	$628,216
Advertising & Promotion	N/A	$126,300	$126,300	$126,300	$126,300
Measurement & Verification	N/A	$28,000	$28,000	$28,000	$28,000
Rebates	N/A	$3,939,431	$3,939,431	$3,939,431	$3,939,431
Other	N/A	$0	$0	$0	$0
Subtotal	N/A	$4,725,697	$4,725,697	$4,725,697	$4,725,697
Utility Revenue Reduction					
Revenue Reduction - Electric	N/A	N/A	$16,747,830	N/A	N/A
Subtotal	N/A	N/A	$16,747,830	N/A	N/A
Participant Costs					
Incremental Capital Costs	$9,506,579	N/A	N/A	$9,506,579	$9,379,752
Incremental O&M Costs	$684	N/A	N/A	$684	$773
Subtotal	$9,507,264	N/A	N/A	$9,507,264	$9,380,526
Total Costs	$9,507,264	$4,725,697	$21,473,527	$14,232,961	$14,106,223
Net Benefit (Cost)	$11,500,887	$6,014,866	($10,732,964)	$767,923	$3,570,577
Benefit/Cost Ratio	2.21	2.27	0.50	1.05	1.25

- Ensures measures within programs are cost-effective when all costs and benefits are included
- Rebates to Participants are a pass-through cost (treated as benefit and cost)

- Ensures programs are cost-effective to individual participants
- Sets cost-effective Rebate level

- Incentivizes Utilities to maximize System Benefits (Revenue Requirements charged to customer base) and minimize program costs (recovery from customer base)
- Measures cost savings to customer base
- Shared Savings Mechanism splits savings between customer base (90%) and utility (10%)

Misc. Filing Cost-Benefit Considerations

Cost-Benefit Analysis Screening

Total Resource Cost Test / Societal Test

- Equipment Acquisition Measures Only
- Ensures Equipment Rebates are dedicated to cost-effective measures

Participant Test

- Ensures programs are cost-effective to individual participants
- Sets cost-effective Bill Credit Level

Rate Impact Measure Test

- Ensures programs are cost-effective to non-participating customers
- Supports recovery of Program Administration and Bill Credits from all customers
- Sets cost-effective Bill Credit Level

Misc. Filing Cost-Benefit Considerations

- Evaluate over lifetime of the measures
- Includes bill credits in future years for Participant Test
- Future bill credits not being asked for recovery
- Used only for TRC/Societal and Participant Screening

- Limited to impacts and costs each program year
- Include Equipment Rebates, Bill Credits and Program Administration
- Rate Impact Measure (RIM) Test includes all costs
- Shared Savings Mechanism based on RIM net benefits
- Incentivizes maximizing benefits to all customers and minimizing program costs

Misc. Filing Cost-Benefit Life-Cycle Analysis Example

THERMAL ENERGY STORAGE (Life-Cycle Analysis) 2021 ELECTRIC GOAL

2021 Net Present Cost Benefit Summary Analysis For All Participants

	Participant Test ($Total)	Utility Test ($Total)	Rate Impact Test ($Total)	Total Resource Test ($Total)	Societal Test ($Total)
Benefits					
Avoided Revenue Requirements					
Generation	N/A	$2,000,000	$2,000,000	$2,000,000	$2,400,000
T & D	N/A	$200,000	$200,000	$200,000	$240,000
Marginal Energy	N/A	$1,500,000	$1,500,000	$1,500,000	$1,800,000
Environmental Externality	N/A	N/A	N/A	N/A	$300,000
Subtotal	N/A	$3,700,000	$3,700,000	$3,700,000	$4,740,000
Participant Benefits					
Bill Reduction - Electric	$500,000	N/A	N/A	N/A	N/A
Rebates from Xcel Energy	$2,500,000	N/A	N/A	$2,500,000	$2,500,000
Incremental Capital Savings	$0	N/A	N/A	$0	$0
Incremental O&M Savings	$0	N/A	N/A	$0	$0
Subtotal	$3,000,000	N/A	N/A	$2,500,000	$2,500,000
Total Benefits	$3,000,000	$3,700,000	$3,700,000	$6,200,000	$7,240,000
Costs					
Utility Project Costs					
Customer Services	N/A	$0	$0	$0	$0
Project Administration	N/A	$200,000	$200,000	$200,000	$200,000
Advertising & Promotion	N/A	$50,000	$50,000	$50,000	$50,000
Measurement & Verification	N/A	$25,000	$25,000	$25,000	$25,000
Rebates	N/A	$2,500,000	$2,500,000	$2,500,000	$2,500,000
Other	N/A	$0	$0	$0	$0
Subtotal	N/A	$2,775,000	$2,775,000	$2,775,000	$2,775,000
Utility Revenue Reduction					
Revenue Reduction - Electric	N/A	N/A	$500,000	N/A	N/A
Subtotal	N/A	N/A	$500,000	N/A	N/A
Participant Costs					
Incremental Capital Costs	$2,500,000	N/A	N/A	$2,500,000	$2,500,000
Incremental O&M Costs	$0	N/A	N/A	$0	$0
Subtotal	$2,500,000	N/A	N/A	$2,500,000	$2,500,000
Total Costs	$2,500,000	$2,775,000	$3,275,000	$5,275,000	$5,275,000
Net Benefit (Cost)	$500,000	$925,000	$425,000	$925,000	$1,965,000
Benefit/Cost Ratio	1.20	1.33	1.13	1.18	1.37

- Avoided Revenue Requirements over Lifetime of Measure
- Includes Cost of Equipment
- Does not measure cost-effectiveness of bill credits (Rebates)

- Ensures programs are cost-effective to individual participants
- Sets cost-effective Bill Credit Level
- Includes bill reduction from current rates

- Ensures programs are cost-effective to non-participating customers
- Supports recovery of Program Administration and Bill Credits from all customers
- Sets cost-effective Bill Credit Level
- Includes bill reduction from current rates
- Utility Test does not include bill reduction from current rates

Northern States Power Company

A Single Year View Can be Misleading for Demand Response

THERMAL ENERGY STORAGE (Single-Year Analysis) 2021 ELECTRIC GOAL

2021 Net Present Cost Benefit Summary Analysis For All Participants

	Participant Test ($Total)	Utility Test ($Total)	Rate Impact Test ($Total)	Total Resource Test ($Total)	Societal Test ($Total)
Benefits					
Avoided Revenue Requirements					
Generation		$200,000	$200,000		
T & D		$20,000	$20,000		
Marginal Energy		$150,000	$150,000		
Environmental Externality		N/A	N/A		
Subtotal		$370,000	$370,000		
Participant Benefits					
Bill Reduction - Electric		N/A	N/A		
Rebates from Xcel Energy		N/A	N/A		
Incremental Capital Savings		N/A	N/A		
Incremental O&M Savings		N/A	N/A		
Subtotal		N/A	N/A		
Total Benefits		$370,000	$370,000		
Costs					
Utility Project Costs					
Customer Services		$0	$0		
Project Administration		$200,000	$200,000		
Advertising & Promotion		$50,000	$50,000		
Measurement & Verification		$25,000	$25,000		
Rebates		$250,000	$250,000		
Other		$0	$0		
Subtotal		$525,000	$525,000		
Utility Revenue Reduction					
Revenue Reduction - Electric		N/A	$50,000		
Subtotal		N/A	$50,000		
Participant Costs					
Incremental Capital Costs		N/A	N/A		
Incremental O&M Costs		N/A	N/A		
Subtotal		N/A	N/A		
Total Costs		$525,000	$575,000		
Net Benefit (Cost)		($155,000)	($205,000)		
Benefit/Cost Ratio		0.70	0.64		

- Not included
- Tests incorporate equipment costs

- Sets cost-effective Bill Credit Level
- Includes bill reduction from current rates
- May fail initially due to Administration Costs

- Does not includes bill reduction from current rates
- Cannot measure cost-effective Bill Credit Level

Cost-Benefit Improves Over Time - Example

THERMAL ENERGY STORAGE (Single-Year Analysis) 2023 ELECTRIC GOAL

2023 Net Present Cost Benefit Summary Analysis For All Participants

	Participant Test ($Total)	Utility Test ($Total)	Rate Impact Test ($Total)	Total Resource Test ($Total)	Societal Test ($Total)
Benefits					
Avoided Revenue Requirements					
Generation		$600,000	$600,000		
T & D		$60,000	$60,000		
Marginal Energy		$450,000	$450,000		
Environmental Externality		N/A	N/A		
Subtotal		$1,110,000	$1,110,000		
Participant Benefits					
Bill Reduction - Electric		N/A	N/A		
Rebates from Xcel Energy		N/A	N/A		
Incremental Capital Savings		N/A	N/A		
Incremental O&M Savings		N/A	N/A		
Subtotal		N/A	N/A		
Total Benefits		$1,110,000	$1,110,000		
Costs					
Utility Project Costs					
Customer Services		$0	$0		
Project Administration		$200,000	$200,000		
Advertising & Promotion		$50,000	$50,000		
Measurement & Verification		$25,000	$25,000		
Rebates		$750,000	$750,000		
Other		$0	$0		
Subtotal		$1,025,000	$1,025,000		
Utility Revenue Reduction					
Revenue Reduction - Electric		N/A	$50,000		
Subtotal		N/A	$50,000		
Participant Costs					
Incremental Capital Costs		N/A	N/A		
Incremental O&M Costs		N/A	N/A		
Subtotal		N/A	N/A		
Total Costs		$1,025,000	$1,075,000		
Net Benefit (Cost)		$85,000	$35,000		
Benefit/Cost Ratio		1.08	1.03		

- Cumulative = Installed Population

- Sets cost-effective Bill Credit Level for Installed Population
- Includes bill reduction from current rates
- Future Years likely pass as Administration Costs become smaller fraction

PARTICIPANT FEEDBACK

Next Steps

Next meeting November 10

Refine discussion of the technologies and incentive mechanisms brought forward – are your questions answered? Have you brought forward your concerns?

Additional technologies or incentive mechanisms to explore – have we vetted these thoroughly enough at this point?

Determine stakeholder positions, consensus building where possible


Xcel Energy®

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

PREPARED FOR

Xcel Energy

PREPARED BY

Ryan Hledik
Ahmad Faruqui
Pearl Donohoo-Vallett
Tony Lee

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.

About the Authors

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

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

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

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

Table of Contents

Executive Summary

Highlights:

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

Background

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

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

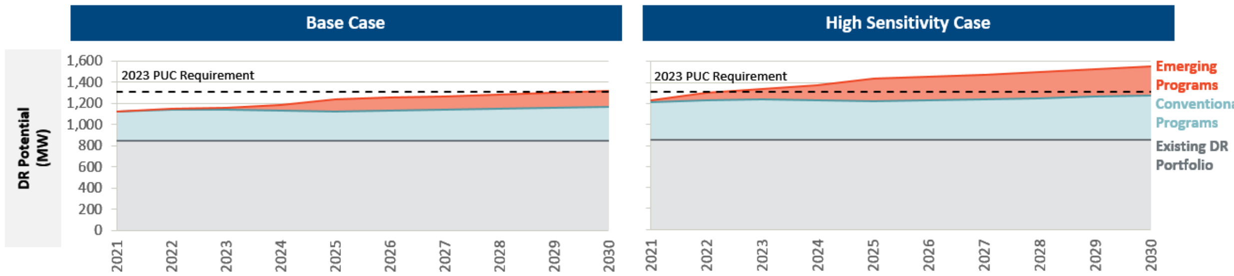
NSP's market may evolve to create more economically favorable conditions for DR than currently expected. For instance, growth in market adoption of intermittent renewable generation could contribute to energy price volatility and an increased need for high-value grid balancing services. Further, the 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 not a forecast of what is likely to happen in the future in NSP's service territory, particularly in the near-term years of the study horizon.

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

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

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

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



2030 Avoided Cost ($M/yr)

Base Case

	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$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.

---

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.

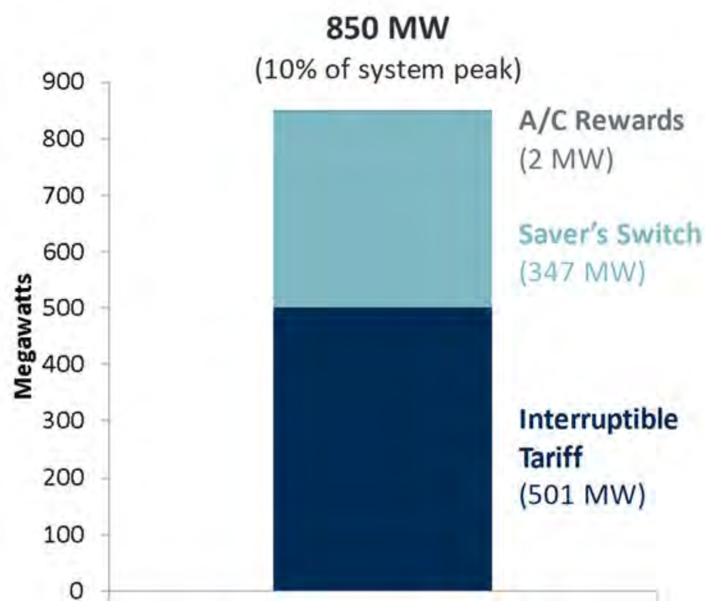
As of 2017, Xcel Energy had 850 MW of DR capability across its NSP service territory, accounting for roughly 10 percent of system peak demand. This capability comes primarily from two programs. The largest is an "interruptible tariff" program, which provides commercial and industrial (C&I) customers 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:

[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).

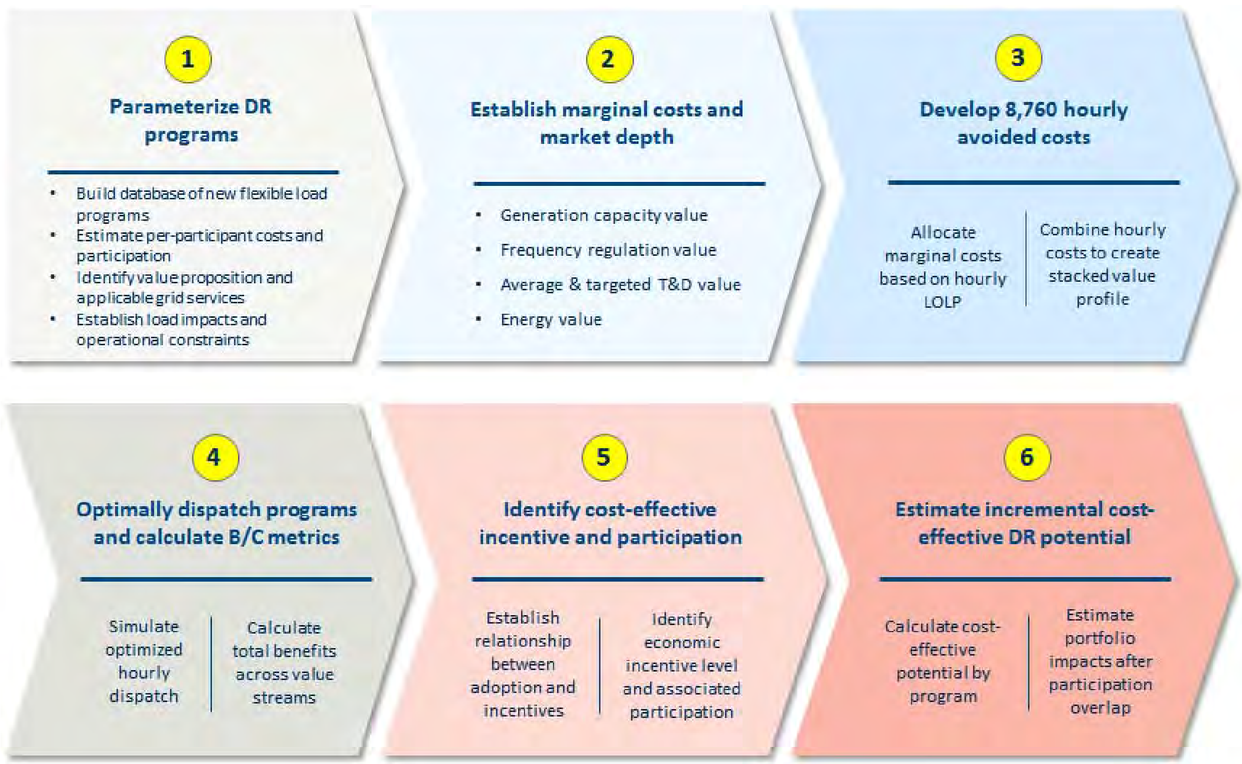
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes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

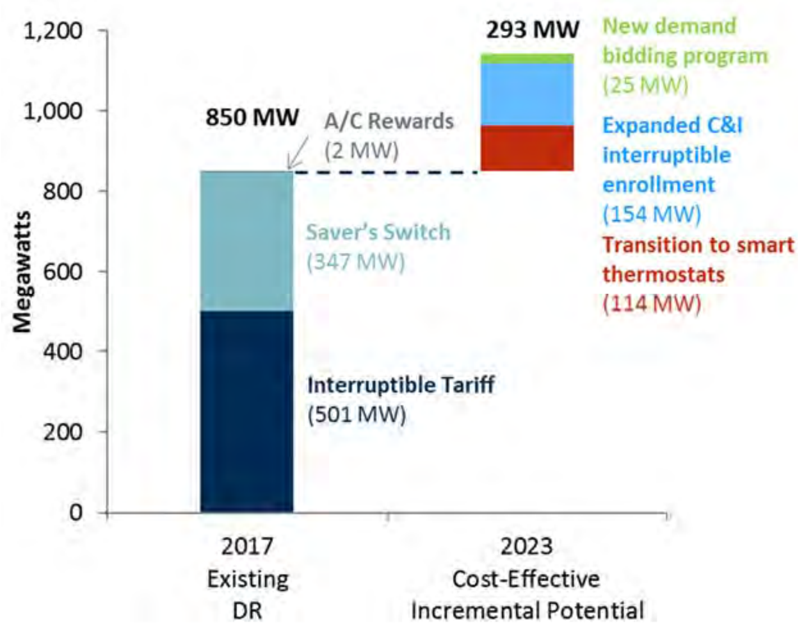
III. Conventional DR Potential in 2023

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.

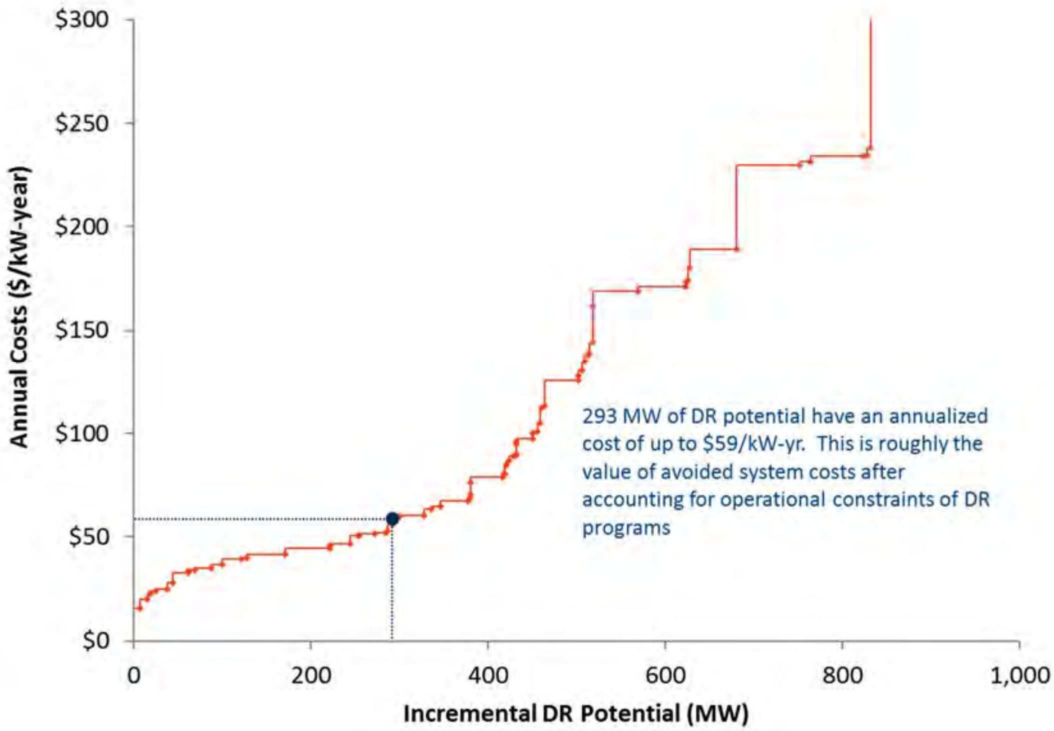
10 NSP has interpreted the PUC's Order to require 400 MW of capacity-equivalent DR, which equates to 391 MW of generator-level load reduction when accounting for the reserve requirement, and 362 MW of meter-level load reduction when also accounting for line losses.

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

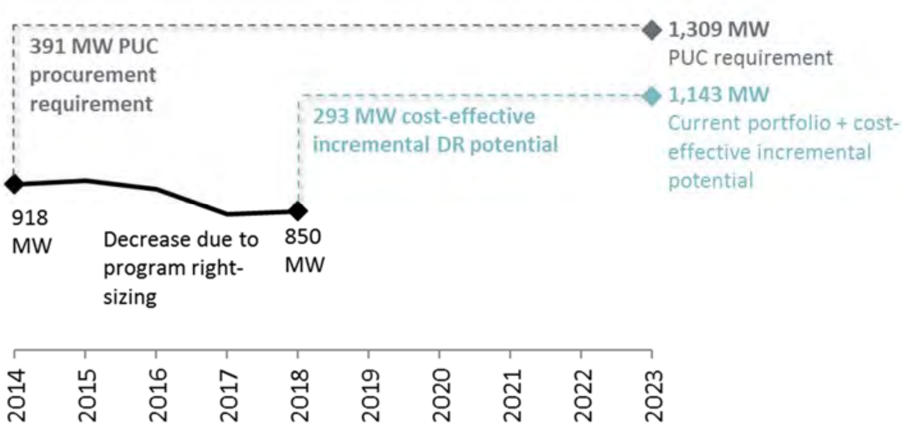
	Requirement (MW)	Notes
Meter level	361.7	Premise-level
Generator level	390.7	Grossed up for 8% line losses
Capacity equivalent	400.0	Grossed up for line losses and reserve requirement

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.

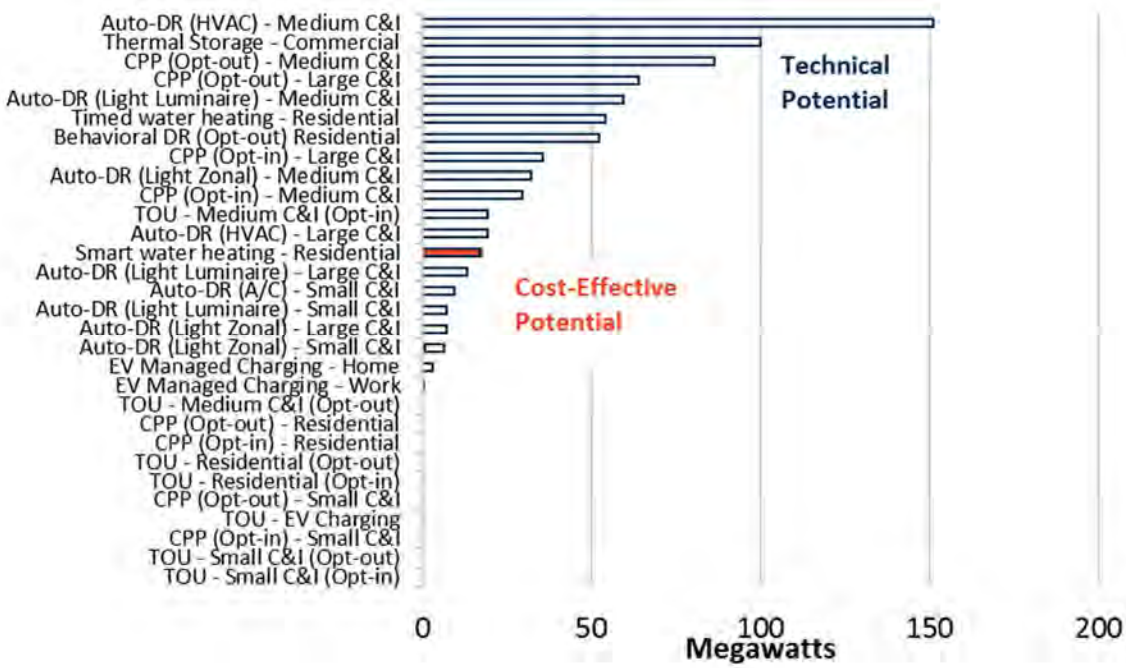
EV charging load control programs also have very modest technical potential in 2023. This is driven in part by a limited projection of EV adoption over the next five years. It is also driven by a lack of coincidence between peak charging load and the timing of the system peak.

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)

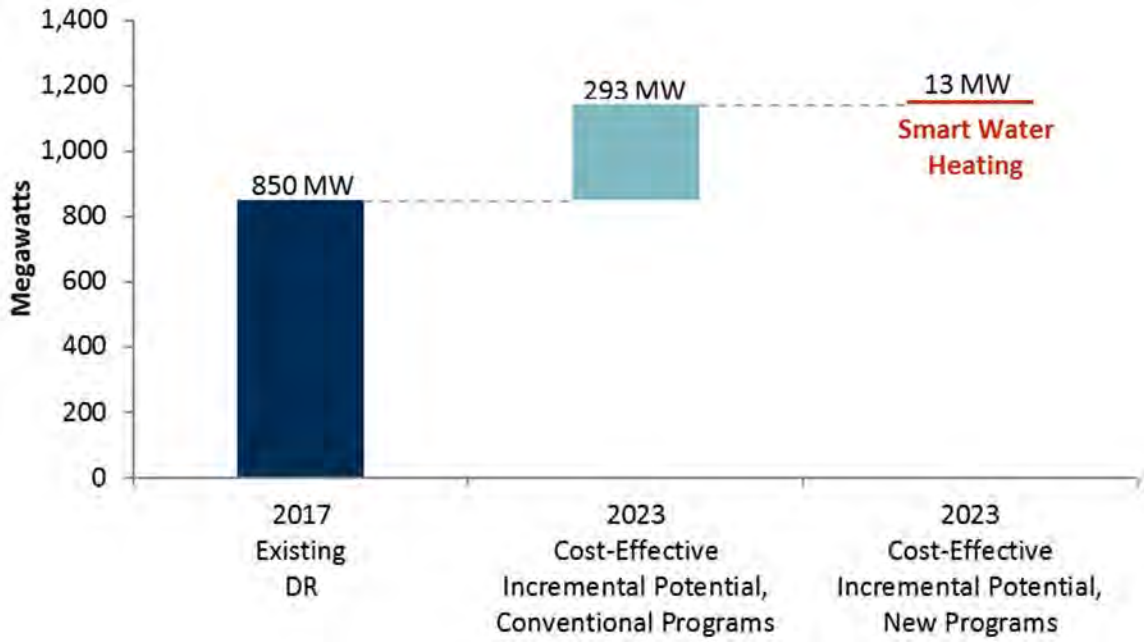


Note: Results reflect NSP system-wide DR potential. Impacts assume each program is offered in isolation; they are not additive. All potential is incremental to NSP's existing portfolio.

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.

---

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

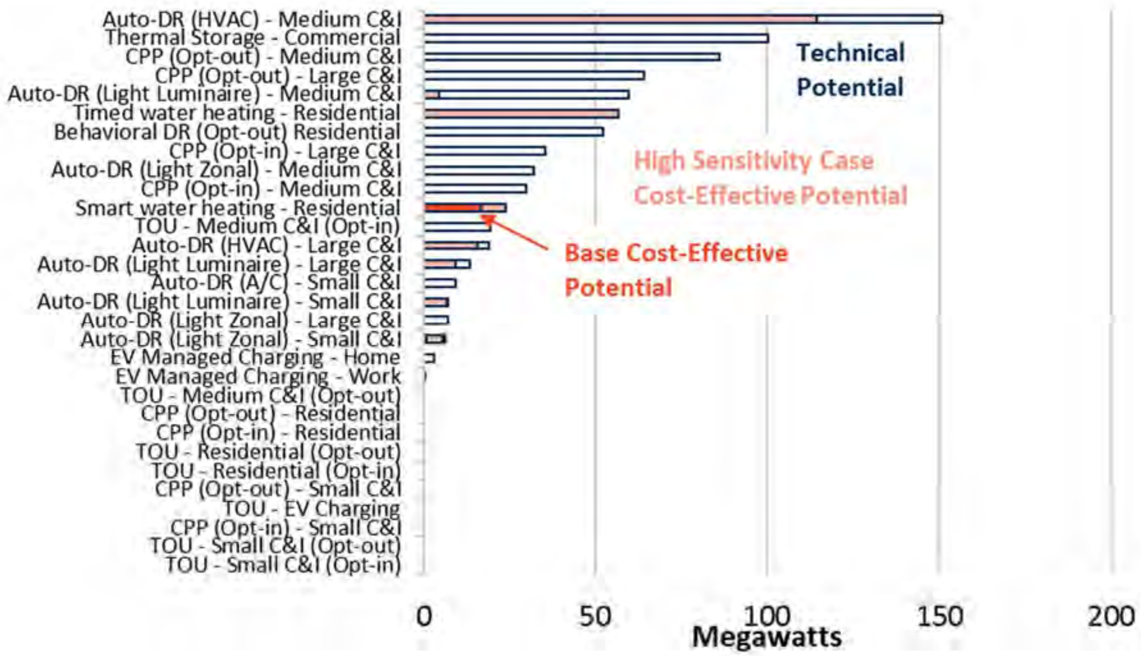
The High Sensitivity Case illustrates the potential for DR under an alternative set of market conditions that are more favorable to DR program economics. As discussed earlier in this report, assumptions behind the High Sensitivity Case are not a forecast of what is likely to happen in the future in NSP's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

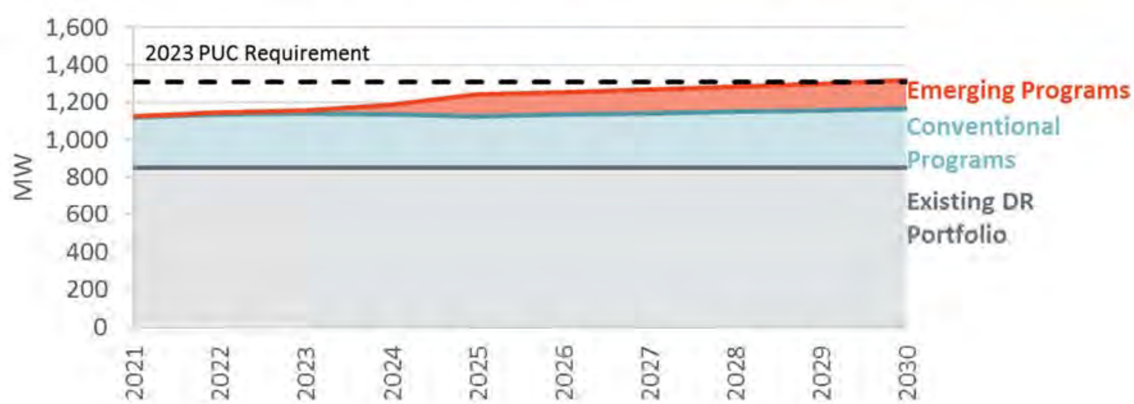
V. Expanded DR Potential in 2030

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)

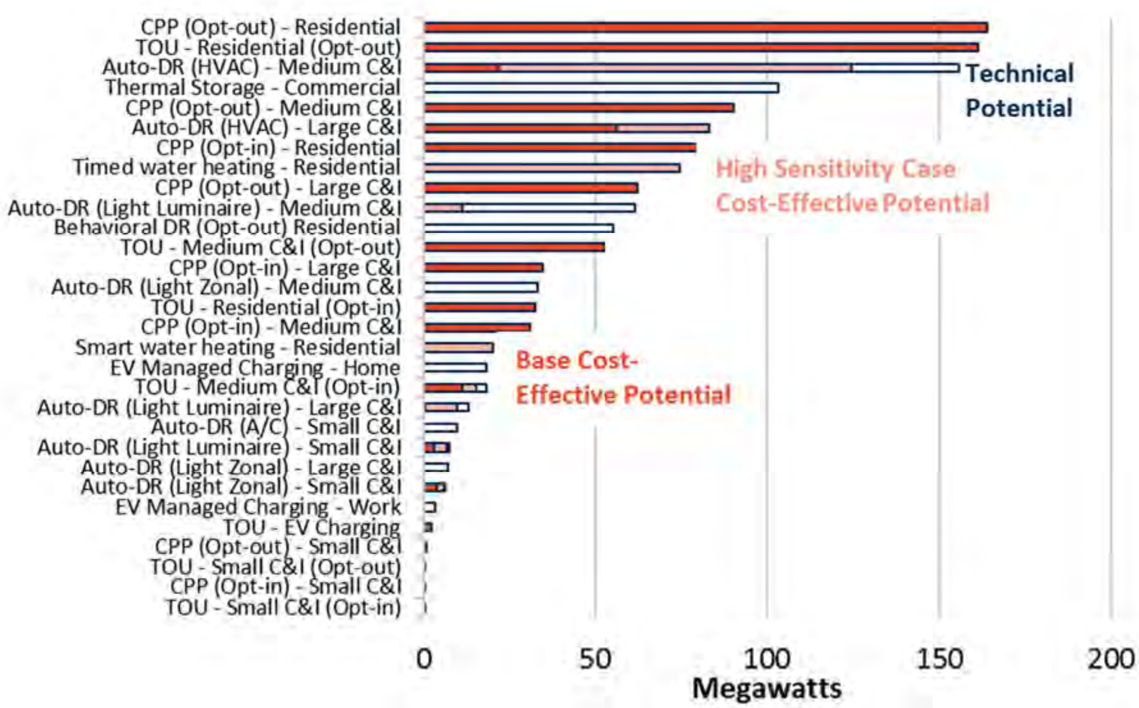
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$5.0	$43.6	$2.8	$0.0	$0.0	$51.4
Emerging Programs	$5.7	$7.4	$0.4	$0.0	$1.2	$14.7
Total	$10.7	$50.9	$3.2	$0.0	$1.2	$66.1

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.

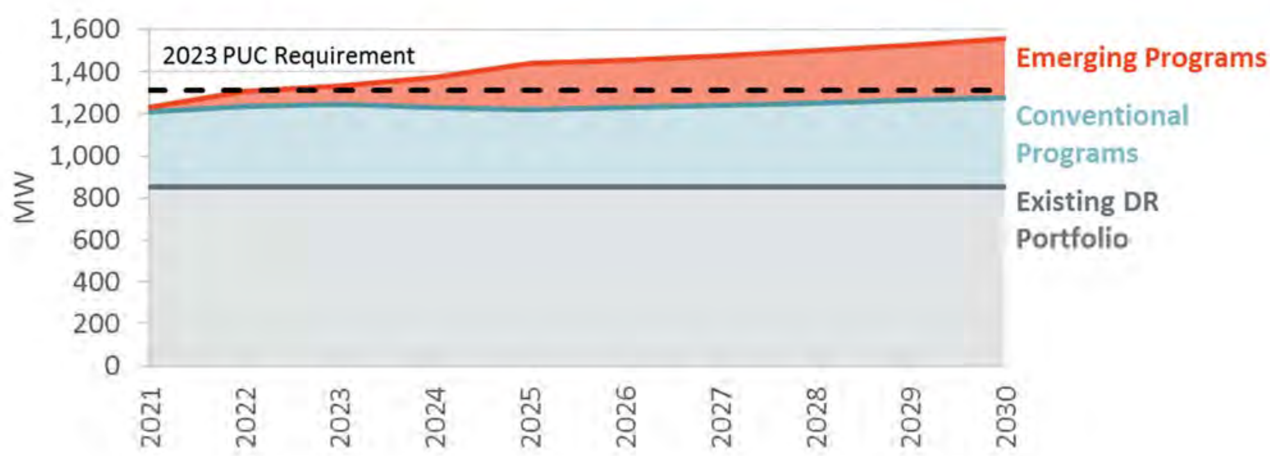
Figure 12: New DR Program Potential in 2030



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)

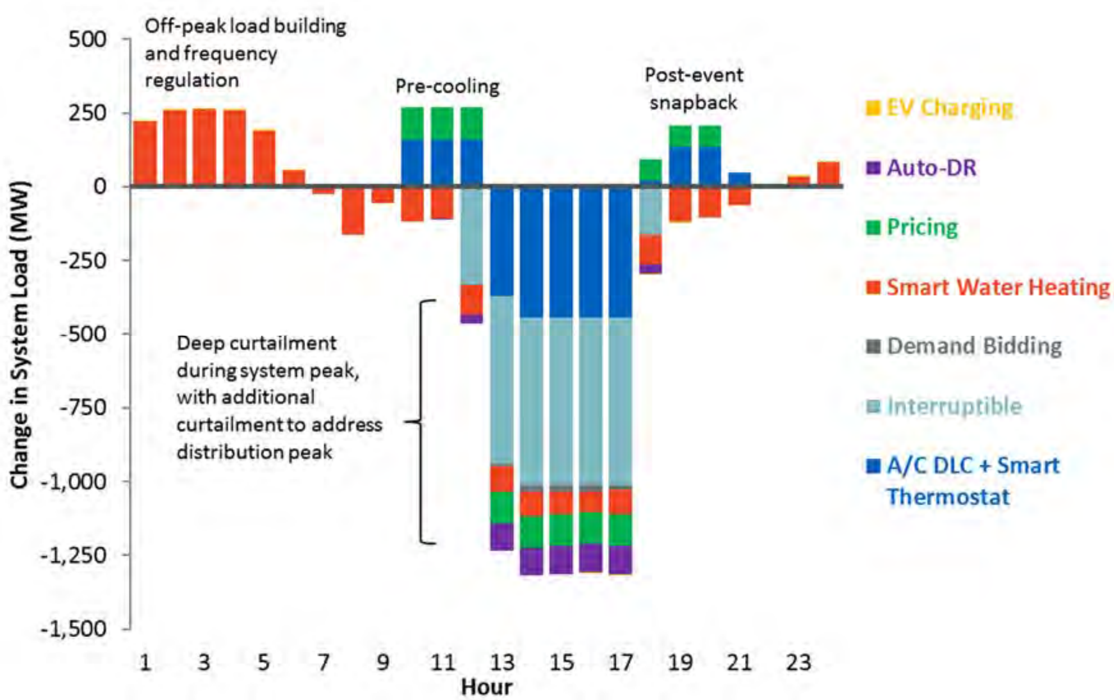
	Energy	Generation Capacity	System Average T&D Deferral	Geotargeted Distribution Deferral	Frequency Regulation	Total
Conventional Programs	$8.6	$69.7	$3.3	$0.0	$0.0	$81.5
Emerging Programs	$19.6	$19.5	$0.8	$0.7	$4.6	$45.2
Total	$28.2	$89.2	$4.0	$0.7	$4.6	$126.8

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)



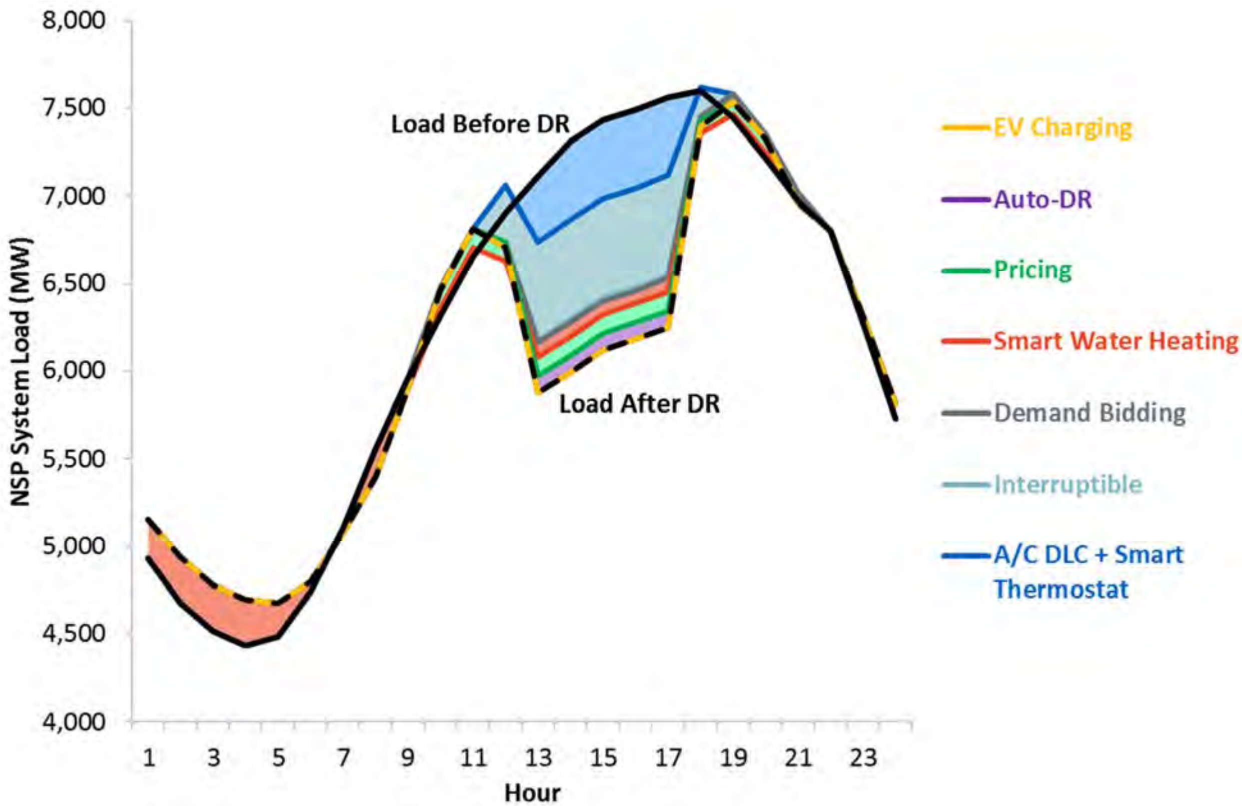
Note: Shown for cost-effective programs identified in 2030, accounting for portfolio overlap.

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.

References

Auto-DR

Alstone, Peter, Jennifer Potter, Mary Ann Piette, Peter Schwartz, Michael A. Berger, Laurel N. Dunn, Sarah J. Smith, Michael D. Sohn, Arian Aghajanzadeh, Sofia Stensson, Julia Szinai, Travis Walter, Lucy McKenzie, Luke Lavin, Brendan Schneiderman, Ana Mileva, Eric Cutter, Arne Olson, Josh Bode, Adriana Ciccone, and Ankit Jain, "2025 California Demand Response Potential Study – Charting California's Demand Response Future: Final Report on Phase 2 Results," March 1, 2017.

Alstone, Peter, Jennifer Potter, Mary Ann Piette, Peter Schwartz, Michael A. Berger, Laurel N. Dunn, Sarah J. Smith, Michael D. Sohn, Arian Aghajanzadeh, Sofia Stensson, Julia Szinai, Travis Walter, Lucy McKenzie, Luke Lavin, Brendan Schneiderman, Ana Mileva, Eric Cutter, Arne Olson, Josh Bode, Adriana Ciccone, and Ankit Jain, "2025 California Demand Response Potential Study – Charting California's Demand Response Future: Phase 2 Appendices A – J," March 1, 2017.

Watson, David S., Sila Kiliccote, Naoya Motegi, and Mary Ann Piette, "Strategies for Demand Response in Commercial Buildings," *ACEEE Summer Study on Energy Efficiency in Buildings*, 3-287 – 3-299, 2006.

Avoided Costs

Decision before the Deputy Commissioner of the Minnesota Department of Commerce, in the matter of Avoided Transmission and Distribution Cost Study for Electric 2017-2019 CIP Triennial Plans, Docket no. E999/CIP-16-541, September 29, 2017.

Energy+Environmental Economics, "Time Dependent Valuation of Energy for Developing Building Efficiency Standards – 2013 Time Dependent Valuation (TDV) Data Sources and Inputs," prepared for the California Energy Commission, February 2011.

MISO, "MTEP 18 Futures – Summary of definitions, uncertainty variables, resource forecasts, siting process and siting results."

Tacka, Natalie and Danielle Martini, "RTO/ISO Regulation Market Comparison," January – April, 2016.

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

Behavioral DR Studies

Bell, Eric, Amanda Stansell, Ankit Jain, Alan Mellovitz, Rachel Charow, Jim Eber, and Tony Bustamante, "Commonwealth Edison Company's Peak Time Savings Program Annual Report – For the year ending May 31, 2017," prepared for Commonwealth Edison Company, August 2017.

Blumsack, Seth and Paul Hines, "Load Impact Analysis of Green Mountain Power Critical Peak Events, 2012 and 2013," March 5, 2015.

Brandon, Alec, John List, Robert Metcalfe, and Michael Price, "The Impact of the 2014 Opower Summer Behavioral Demand Response Campaigns on Peak-Time Energy Consumption," prepared for Opower, June 28, 2014.

Buckley, Brian, "Putting More Energy into Peak Savings: Integrating Demand Response and Energy Efficiency Programs in the Northeast and Mid-Atlantic," *ACEEE Summer Study on Energy Efficiency in Buildings*, 6-1 – 6-13, 2006.

Cook, Jonathan, Marshall Blundell, and Michael Sullivan, "Behavioral Demand Response Study – Load Impact Evaluation Report," prepared for the Pacific Gas & Electric Company, January 11, 2016.

Illume Advising, LLC, "MyMeter Multi-Utility Impact Findings," prepared for Accelerated Innovations, March 2014.

Kirchner, Derek, Debbie Brannan, Carly Olig, Will Sierzchula, "The Reliability of Behavioral Demand Response," 2017 International Energy Program Evaluation Conference, Baltimore, MD, 2017.

Kuennen, Craig R., "Glendale Water and Power Smart Grid Program," prepared for the California Energy Commission, CEC-500-2015-090, July 2015.

Opower, "Transform Every Customer into a Demand Response Resource: How Utilities Can Unlock the Full Potential of Residential Demand Response," 2014.

Thayer, David, Wendy Brummer, Brian Arthur Smith, Rick Aslin, and Jonathan Cook, "Is Behavioral Energy Efficiency and Demand Response Really Better Together?" *ACEEE Summer Study on Energy Efficiency in Buildings*, 2-1 – 2-11, 2016.

Ward, Kathleen, Dana Max, Bill Provencher, Brent Barkett, "Smart Energy Manager Program 2014 Evaluation Report (01/01/2014 – 12/31/2014)," presented to Baltimore Gas and Electric, May 13, 2015.

CTA-2045

Bonneville Power Administration, CTA-2045 Water Heater Demonstration Report," November 9, 2018.

Electric Power Research Institute, "Economic and Cost/Benefit Analysis for Deployment of CEA-2045-Based DR-Ready Appliances," December 2014.

Thomas, Chuck, "Field Test Results of the Consumer Technology Association's CTA-2045 Demand Response Standard," presented at the 35th PLMA Conference, April 5, 2017.

Dynamic Pricing

Faruqui, Ahmad, Sanem Sergici, and Cody Warner, "*Arcturus 2.0*: A meta-analysis of time-varying rates for electricity," *The Electricity Journal*, 30, 64-72, 2017.

Faruqui, Ahmad and Sanem Sergici, "Arcturus: International Evidence on Dynamic Pricing," The Electricity Journal, vol. 26, issue 7, 55-65, 2013.

Faruqui, Ahmad, Ryan Hledik, and Neil Lessem, "Smart by Default," *Public Utilities Fortnightly*, August 2014.

EV Charging Control Studies

BMW Group and Pacific Gas and Electric Company, "BMW i Charge Forward: PG&E's Electric Vehicle Smart Charging Pilot," 2017.

Cook, Jonathan, Candice Churchwell, and Stephen George, "Final Evaluation for San Diego Gas & Electric's Plug-in Electric Vehicle TOU Pricing and Technology Study," submitted to San Diego Gas & Electric, February 20, 2014.

DiUS, "Demand Management of Electric Vehicle Charging using Victoria's Smart Grid: Project report," May 2013.

Electric Power Research Institute, "Pepco Demand Management Pilot for Plug-In Vehicle Charging in Maryland – Final report – Results, insights, and customer metrics," prepared on behalf of Pepco, Technical Report 300200XXXX, April 2016.

Energy+Environmental Economics, "California Transportation Electrification Assessment: Phase 2: Grid Impacts," October 23, 2014.

Herter, Karen, "SMUD's EV Innovators Pilot – Load Impact Evaluation," prepared for the Sacramento Municipal Utility District, December 2014.

M.J. Bradley & Associates LLC, "Electricity Pricing Strategies to Reduce Grid Impacts from Plug-in Electric Vehicle Charging in New York State – Final report," prepared for the New York State Energy Research and Development Authority, NYSERDA Report 15-17, June 2015.

Murach, John, "BGE Electric Vehicle Off Peak Charging Pilot," 2017.

Smart Electric Power Alliance, "Utilities and Electric Vehicles – The case for managed charging," April 2017.

Southern California Edison, "Southern California Edison Plug-In Electric Vehicle (PEV) Workplace Charging Pilot," December 31, 2014.

Thermal Energy Storage

Hart, Jonathan, Greg Miller, and Amrit Robbins, "Small Thermal Energy Storage and its Role in our Clean Energy Future," *ACEEE Summer Study on Energy Efficiency in Buildings*, 3-1 – 3-12, 2016.

Ice Energy, "Ice Bear 20 Case Study – Home in Santa Ynez, CA," November 2016.

Yin, Rongxin, Doug Black, Mary Ann Piette, and Klaus Schiess, "Control of Thermal Energy Storage in Commercial Buildings for California Utility Tariffs and Demand Response," prepared for the California Energy Commission, CEC-500-2015-XXX, August 2015.

Load Flexibility Studies

Abdisalaam, Ahmed, Ioannis Lampropoulos, Jasper Frunt, Geert P.J. Verbong, and Wil L. Kling, "Assessing the economic benefits of flexible residential load participation in the Dutch day-ahead auction and balancing market," Conference paper: 2012 9th International Conference on the European Energy Market, May 2012.

Alstone, Peter, Jennifer Potter, Mary Ann Piette, Peter Schwartz, Michael A. Berger, Laurel N. Dunn, Sarah J. Smith, Michael D. Sohn, Arian Aghajanzadeh, Sofia Stensson, Julia Szinai, Travis Walter, Lucy McKenzie, Luke Lavin, Brendan Schneiderman, Ana Mileva, Eric Cutter, Arne Olson, Josh Bode, Adriana Ciccone, and Ankit Jain, "2025 California Demand Response Potential Study – Charting California's Demand Response Future: Final Report on Phase 2 Results," March 1, 2017.

D'hulst, R., W. Labeeuw, B. Beusen, S. Claessens, G. Deconinck, and K. Vanthournout, "Demand response flexibility and flexibility potential of residential smart appliances: Experiences from large pilot test in Belgium," *Applied Energy*, 155, 79-90, 2015.

De Coninck, Roel and Lieve Helsen, "Bottom-up Quantification of the Flexibility Potential of Buildings," Conference paper: Building Simulation, 13th International Conference of the International Building Performance Simulation Association, January 2013.

Dyson, Mark, James Mandel, Peter Bronski, Matt Lehrman, Jesse Morris, Titiaan Palazzi, Sam Ramirez, and Hervé Touati, "The Economics of Demand Flexibility: How "flexiwatts" create quantifiable value for customers and the grid," Rocky Mountain Institute, August 2015.

Eto, Joseph, H., John Undrill, Ciaran Roberts, Peter Mackin, and Jeffrey Ellis, "Frequency Control Requirements for Reliable Interconnection Frequency Response," prepared for the Office of Electric Reliability Federal Energy Regulatory Commission, February 2018.

Goldenberg, Cara, Mark Dyson, and Harry Masters, "Demand Flexibility – The key to enabling a low-cost, low-carbon grid," Rocky Mountain Institute, February 2018.

Lopes, Rui Amaral, Adriana Chambel, João Neves, Daniel Aelenei, João Martins, "A literature review of methodologies used to assess the energy flexibility of buildings," *Energy Procedia*, 91, 1053-1058, 2016.

O'Connell, Sarah, and Stefano Riverso, "Flexibility Analysis for Smart Grid Demand Response," 2017.

Olsen, D. J., N. Matson, M. D. Sohn, C. Rose, J. Dudley, S. Coli, S. Kiliccote, M. Hummon, D. Palchak, J. Jorgenson, P. Denholm, O. Ma., "Grid Integration of Aggregated Demand Response, Part 1: Load Availability Profiles and Constraints for the Western Interconnection," LBNL-6417E, 2013.

Potter, Jennifer and Peter Cappers, "Demand Response Advanced Controls Framework and Assessment of Enabling Technology Costs," prepared for the Office of Energy Efficiency and Renewable Energy U.S. Department of Energy, August 2017.

Starke, Michael, Nasr Alkadi, and Ookie Ma, "Assessment of Industrial Load for Demand Response across U.S. Regions of the Western Interconnect," prepared for the Energy Efficiency and Renewable Energy U.S. Department of Energy, ORNL/TM-2013/407, September 2013.

Stoll, Brady, Elizabeth Buechler, and Elaine Hale, "The Value of Demand Response in Florida," *The Electricity Journal*, 30, 57-64, 2017.

Water Heating

Hledik, Ryan, Judy Chang, and Roger Lueken, "The Hidden Battery – Opportunities in Electric Water Heating," prepared for NRECA, NRDC, and PLMA, January 2016.

Other Reviewed Studies

Advanced Energy Management Alliance, "Advancing Demand Response in the Midwest – Expanding untapped potential," February 12, 2018.

Applied Energy Group, "State of Michigan Demand Response Potential Study – Technical Assessment," prepared for the State of Michigan, September 29, 2017.

Chew, Brenda, Brett Feldman, Debyani Ghosh, and Medha Surampudy, "2018 Utility Demand Response Market Snapshot," September 2018.

Demand Side Analytics, LLC, "Potential for Peak Demand Reduction in Indiana," prepared for the Indiana Advanced Energy Economy, February 2018.

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

Faruqui, Ahmad, Ryan Hledik, David Lineweber, and Allison Shellaway, "Estimating Xcel Energy's Public Service Company of Colorado Territory Demand Response Market Potential," prepared for Xcel Energy, June 11, 2013.

FERC Staff, "2018 Assessment of Demand Response and Advanced Metering," November 2018.

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

Hledik, Ryan, Ahmad Faruqui, and Lucas Bressan, "Demand Response Market Research: Portland General Electric, 2016 to 2035," prepared for Portland General Electric, January 2016.

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).

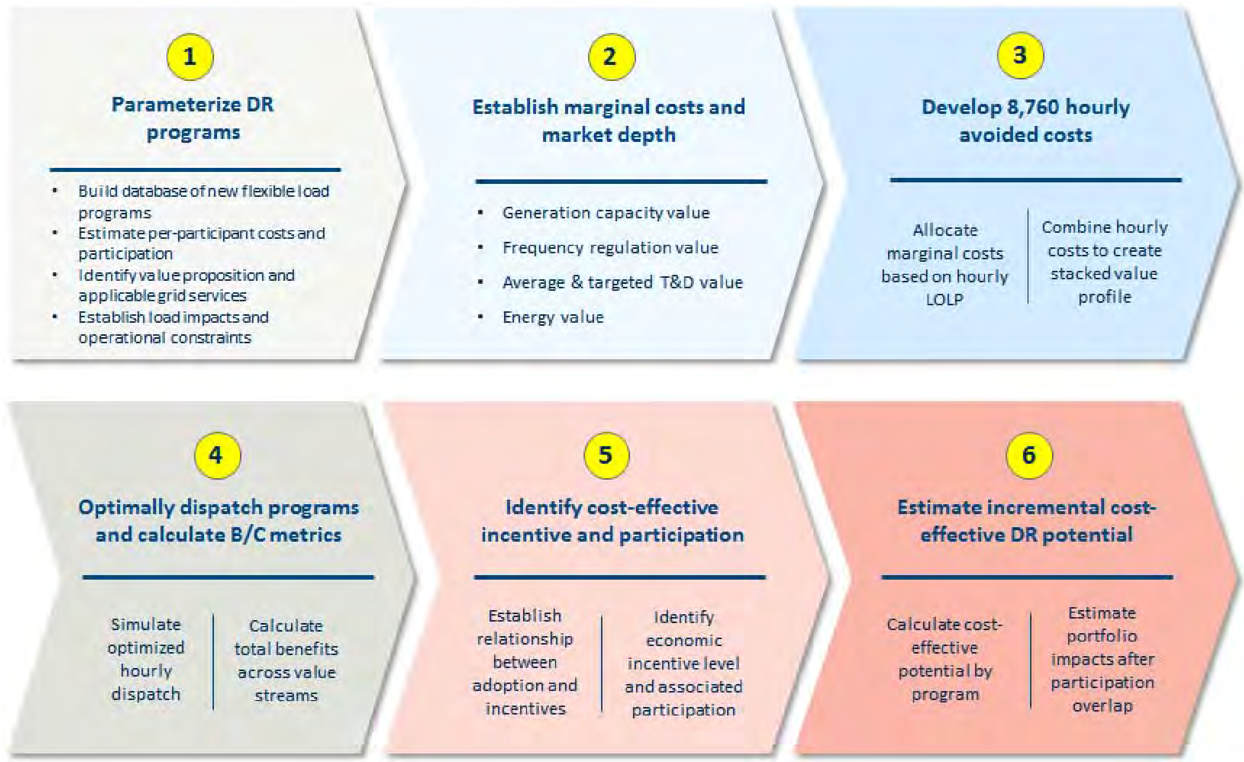
- **Sophisticated DR program dispatch:** DR program dispatch is optimized subject to detailed accounting for the operational constraints of the program. In addition to tariff-related program limitations (e.g., how often the program can be called, hours of the day when it can be called), Load*Flex* includes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

---

[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.

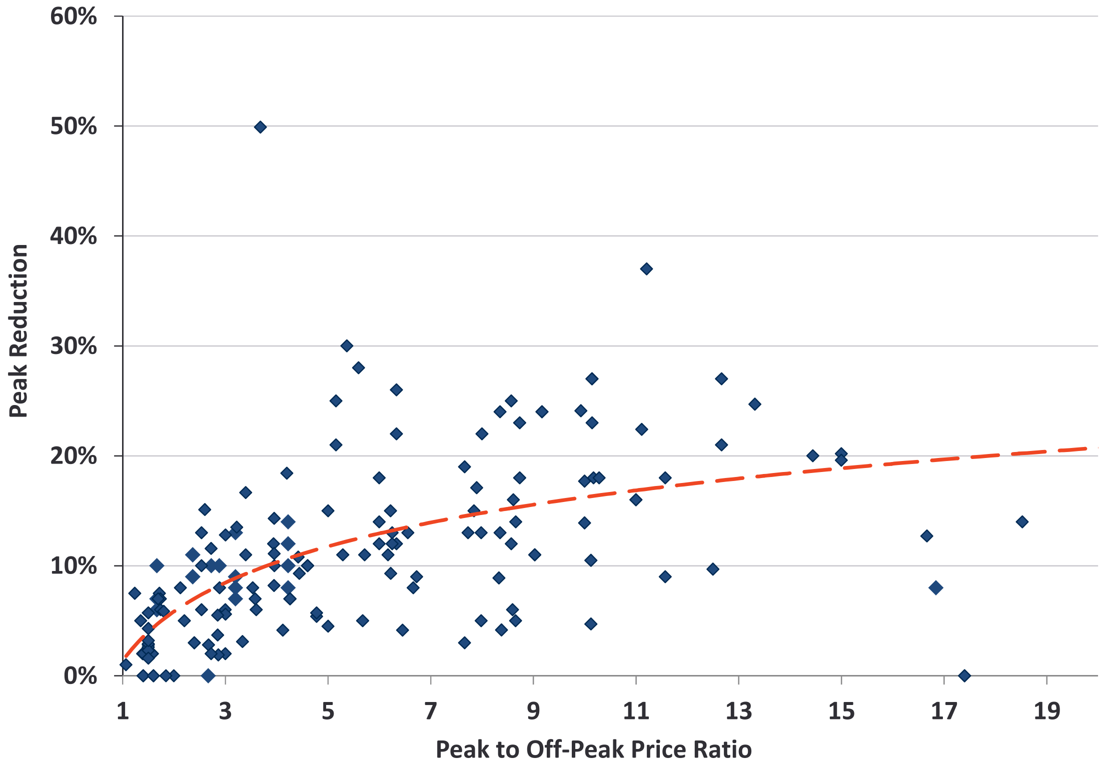
22 Pilot programs reviewed include BMW and PG&E's i Charge Forward Pilot, SCE's Workplace Charging Pilot, SMUD's EV Innovators Pilot, SDG&E's Power Your Drive Pilot, and United Energy's EV smart grid demonstration project.

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

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

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

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

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

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

Avoided generation capacity costs

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

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

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

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

Table 9: Combustion Turbine Cost of New Entry Calculation

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

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

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

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

Avoided transmission capacity costs

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

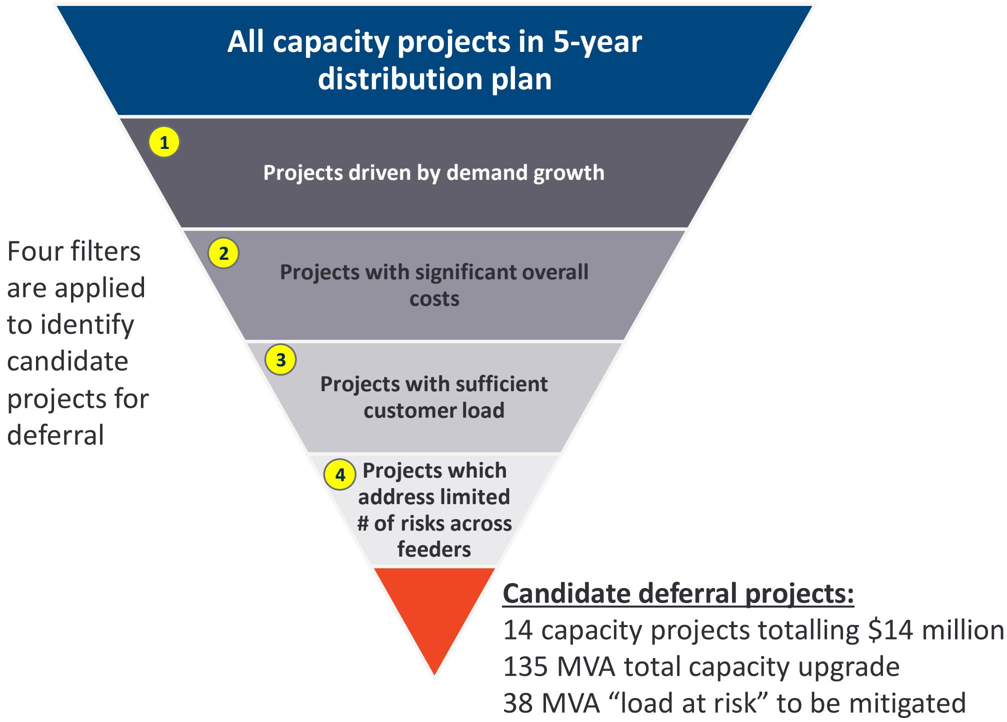
After applying the above criteria, up to roughly 10% of the cost of NSP's 5-year plan remained as potentially deferrable through the use of DR. We have assumed linear growth in NSP's distribution capacity needs, meaning the geo-targeted distribution deferral opportunity increases by this amount every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

---

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

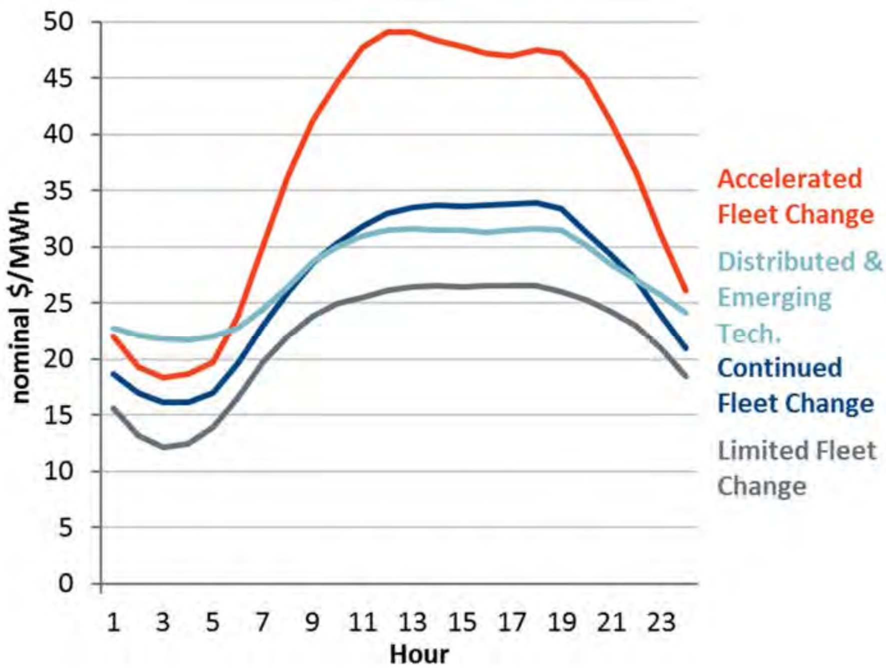
---

[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

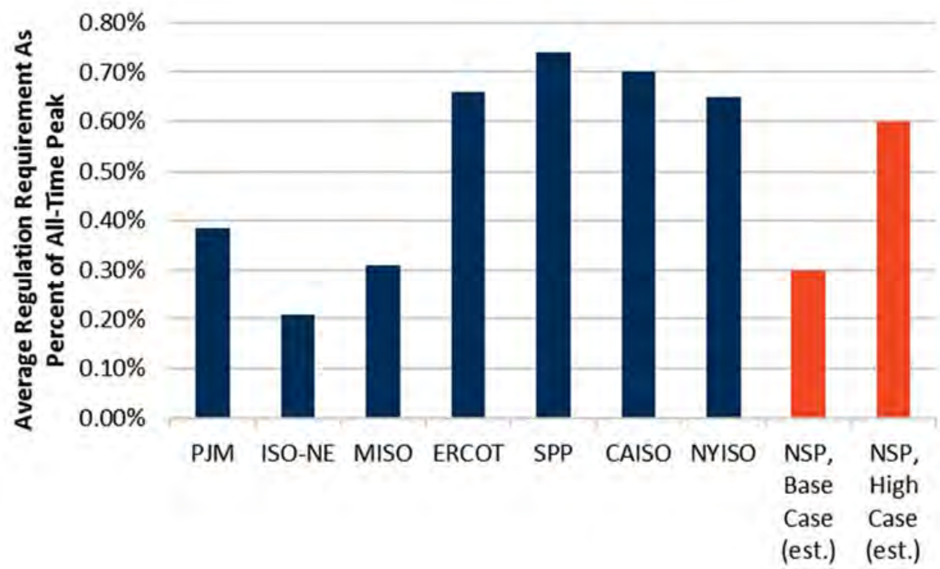
The load of some end-uses can be increased or decreased in real time to mitigate system imbalances. The ability of qualifying DR programs to provide frequency regulation was modeled, as this is the highest-value ancillary service.

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

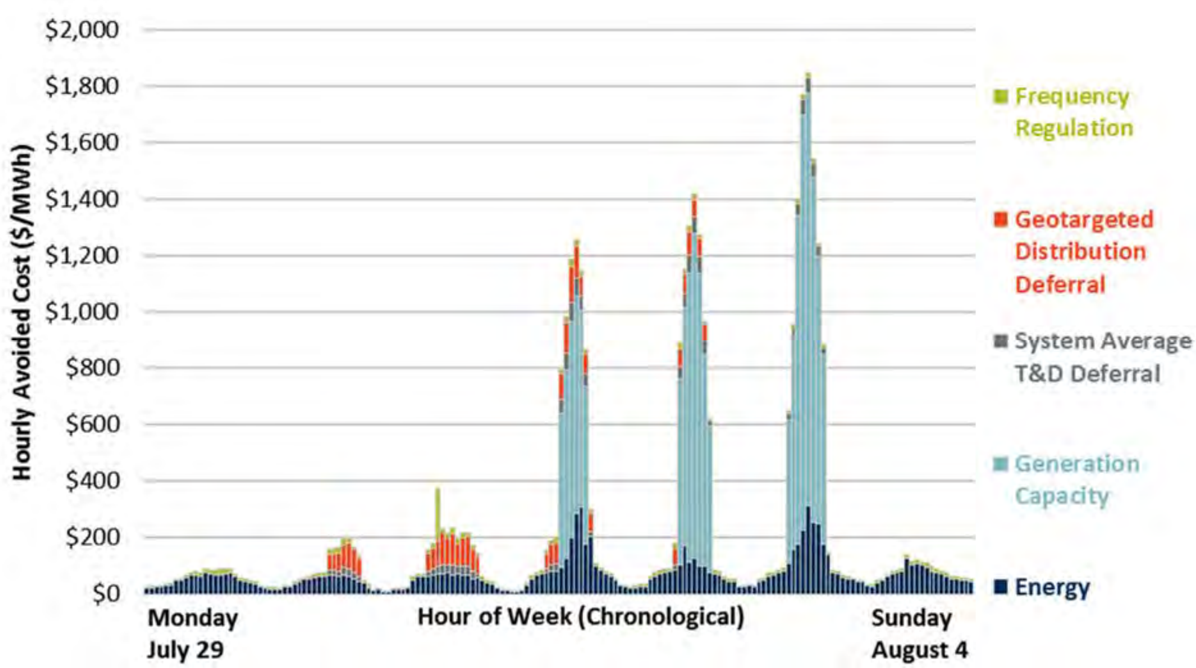
35 Capacity value was allocated proportional to MISO gross load because NSP is required to use its MISO-coincident peak for resource adequacy planning decisions.

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)



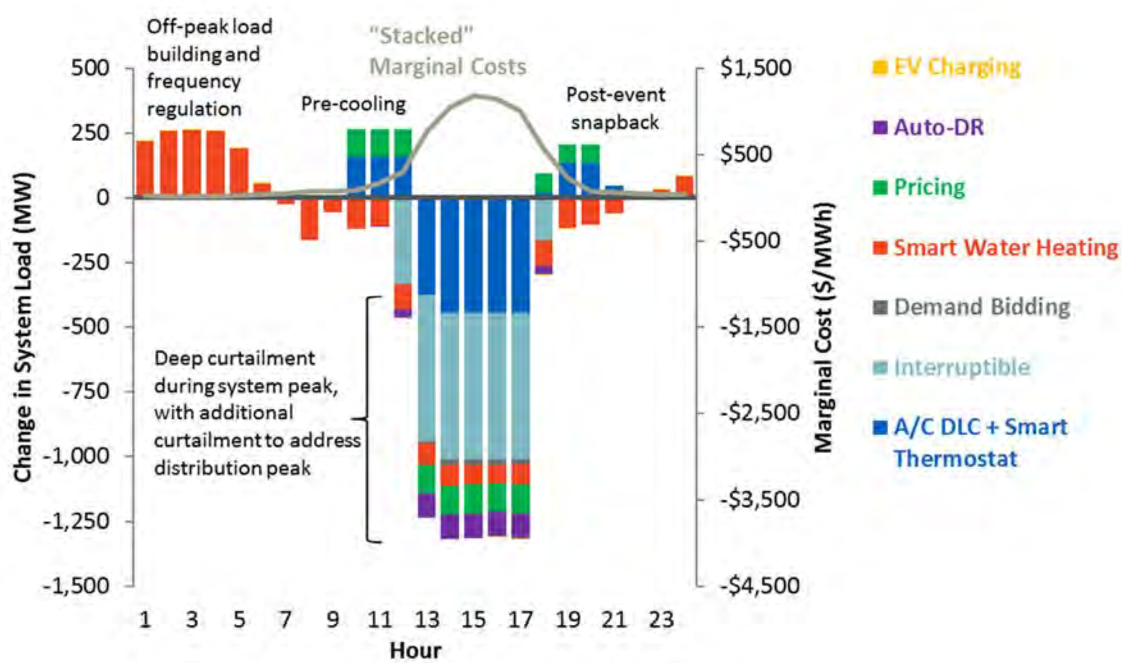
Notes: Marginal costs reflect avoided costs from the 2030 High Sensitivity Case.

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%

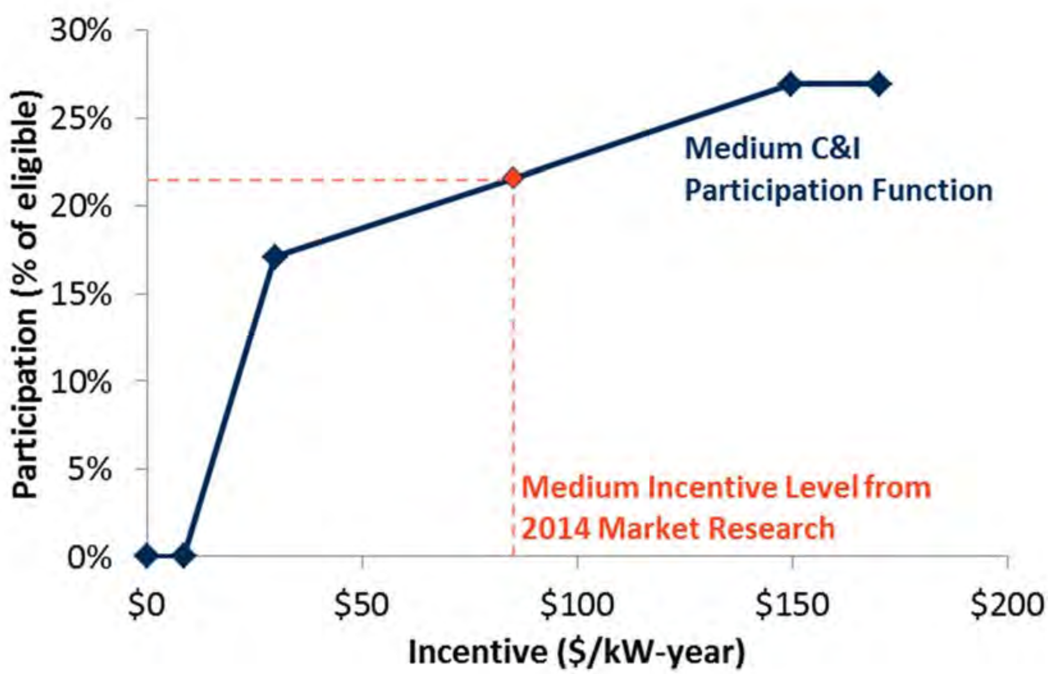
Notes:
Participation rates shown for programs when offered independently (i.e. rates do not account for program overlap).

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.

BOSTON
NEW YORK
SAN FRANCISCO

WASHINGTON
TORONTO
LONDON

MADRID
ROME
SYDNEY

THE Brattle GROUP

Attachment E

Summary
Demand Response Incentive Mechanism
Stakeholder Meeting No. 3

November 10, 2020

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE COMMISSION INVESTIGATION TO IDENTIFY AND DEVELOP PERFORMANCE METRICS AND POTENTIALLY, INCENTIVES FOR XCEL ENERGY'S ELECTRIC UTILITY OPERATIONS

DOCKET NO. E002/CI-17-401

DEMAND RESPONSE INCENTIVE MECHANISM

SUMMARY – STAKEHOLDER MEETING NO. 3

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (the Company), submits to the Minnesota Public Utilities Commission (Commission) this Meeting Summary Report in accordance with the Minnesota Public Utilities Commission's April 16, 2020 ORDER ESTABLISHING METHODOLOGIES AND REPORTING SCHEDULES in the above-noted docket.

Ordering Paragraph No. 1.f. instructed Xcel Energy to:

> *In consultation with the Department and interested stakeholders, develop and file a demand response financial incentive for Commission consideration by the end of the first quarter of 2021.*

On September 15, 2020 the Company served notice of three stakeholder meetings to discuss the development of a demand response performance incentive mechanism. The overall intent for the meetings is to comply with the Commission's Order, follow the same transparent and collaborative stakeholder process utilized in the Performance Based Ratemaking (PBR) metrics development in the present proceeding, and provide information and mechanism tools for stakeholders' review and analysis towards developing a demand response financial incentive recommendation to the Commission.

While not required as part of the Commission's Order, we provide this summary of the third and final online stakeholder meeting conducted via Teams platform on November 10, 2020 - for transparency of process. General stakeholder questions and Company responses are included in this summary report to document the direction of the discussion. The goal of this third workshop was to engage deeper discussion and provide attendees with detail behind the proposed incentive mechanism, including the cost-benefit analysis tests we recommend as appropriate in determining cost-effectiveness and how that relates to a financial incentive for demand response. Additionally, efforts were made to determine outstanding areas of concern and consensus.

Participants included:

Participant	Organization	Participant	Organization
Mike Bull	Ctr for Energy & Env	Isabel Ricker	Fresh Energy
Tricia DeBleekere	Dept of Commerce	Grey Staples	Mendota Group
John Kundert	Dept of Commerce	Joe Sathe	Suburban Rate Authority
Chris Villareal	RStreet Institute	Stacy Miller	City of Minneapolis
Brian Millberg	City of Minneapolis	Kelly Martone	Public Utilities Comm
Farah Mandich	Xcel Energy	PJ Martin	Xcel Energy
Chris Davis	Dept of Commerce	Ashly Mcfarlane	Xcel Energy
Andrew Twite	Office of Attorney General	Brian Lebens	Office of Attorney General
Audrey Partridge	Ctr for Energy & Env	Thor Bjork	Xcel Energy
Brian Doyle	Xcel Energy	Shawn White	Xcel Energy
Jessie Peterson	Xcel Energy	Jeremy Petersen	Xcel Energy
Crystal Gottschalk	Xcel Energy	Bridget Dockter	Xcel Energy

We provided a PowerPoint presentation to attendees prior to the meeting, which is included as Attachment A to this Report.

The remainder of this Report is organized as follows:

- Section I addresses the meeting objectives;
- Section II discusses our proposed Load Flexibility Plan filing, cost-benefit analysis, and proposed Demand Response Incentive Mechanism;
- Section III describes positions feedback from participants; and
- Section IV discusses filing recommendations made by participants.

I. MEETING OBJECTIVES

In meeting No. 1, we provided a historical look at the PBR process in this docket. In meeting No. 2, we again reviewed the Commission's April 16, 2020 Order, the objectives to maintain the same transparent and collaborative process as was used in the initial PBR development, intent to delve deeper into the incentive mechanism discussion, and our desire to open the conversation to stakeholder ideas for demand response measures and/or incentive mechanisms. In meeting No. 3, we again reviewed the Commissioners' Order, and the same transparent and collaborative objectives as the two previous meetings. Meeting No. 3 was intended to provide for an in-depth discussion of our proposed demand response measures and the incentive mechanism we adjusted following the stakeholder feedback at the previous meeting. Lastly, meeting No. 3 allowed the opportunity for parties to voice remaining concerns and where possible, areas of consensus.

<u>Q&A</u>
No clarifying questions were asked by attending parties at this time.

II. LOAD FLEXIBILITY PLAN FILING, COST-BENEFIT ANALYSIS, AND DEMAND RESPONSE INCENTIVE MECHANISM

The Company provided additional detail on the measures/products we will likely propose in the Load Flexibility Plan filing and the revised incentive mechanism, following stakeholder feedback at the previous meeting. At this time, we are considering for inclusion programs and measures such as strategic electrification through water heaters and heat pumps, static electric vehicle charging optimization, peak flex credit, business load shifting and an electric vehicle school bus charging pilot. The cost-benefit analysis test used to determine if the product/measure are cost-effective would be the Societal and the Price Signal Test. The latter is an adaptation of the Rate Payer Impact Test (RIM) that includes avoided carbon.
A summary of the meeting discussion is included below in question and answer format.

<u>Q&A</u>

1. Is Xcel Energy proposing to apply the RIM test on all programs, or only those that have a price signal?

   <u>Response</u>: We will run the test on all programs to allow us to rebate or pay more within the program, but we are proposing to cap the credit to ensure

customers will not pay more than they would for the supply side resources, including generation, transmission and distribution capacity and electric energy.

2. Will the RIM test screen the SHED programs out?

   Response: Load flexibility programs generally fare better than energy efficiency programs because they better align with peak or expensive times. During these expensive hours, the marginal supply side resource cost is higher than the volumetric rate charged to customers. In contrast, energy efficiency programs save energy throughout the year, with the majority of hours having a higher volumetric rate than the marginal supply side resource cost. In an extreme case, if the cost-effectiveness was so tight, we would not be able to pay a rebate for it.

3. Is Xcel Energy thinking of these programs more broadly than just peak periods or more expensive periods of time?

   Response: Yes, there is economic value in using energy during times of negative energy that is a benefit to customers.

4. Please clarify if the Societal or the RIM test is the screening for the programs?

   Response: It is a two-step process. The Societal Test determines what we should pursue, just as it is in CIP today. The Price Signal Test determines how much we pay.

5. Why would the SHED programs not remain in CIP? What can't you do or what value isn't captured under that regulatory structure versus this one?

   Response: Our CIP programs require energy savings, but pursuant to Minnesota Statute, not all programs that fall under demand response will show energy savings; therefore, such programs are not eligible for our CIP funding. Where programs meet the energy saving criteria within CIP, we are likely to seek approval in CIP but may consider the Load Flexibility Plan if efficiencies exist.

6. What is Xcel Energy's position on demand response aggregators, and how can that fit into the bigger picture?

   Response: We are open to looking at a business model that would operate within our program offerings as well as operationally. We have worked with aggregators in other states. The models need to meet the same criteria we do, which we have found to be challenging.[1]

7. How will Xcel Energy handle reverse demand response? As you see a +/-, will your system be at a cross hairs?

   Response: Reverse demand response will seek to target times of excess renewable generation or negative pricing, which has an economic benefit for all customers.

8. Is the RIM test used to calculate net benefits?

   Response: The RIM test plus the value of avoided carbon referred to as the Price Signal Test is used to determine the cap on the proposed incentive. The incentive is a percent of our expenditures, based on performance, and is netted out of the RIM test plus avoided carbon benefits and capped.

9. What is included in the Price Signal Test? The Department of Commerce has the position that you should use emissions that are on the margin if you are building load.[2] This discussion has come out most recently in the electric vehicle discussions.

   Response: The values are currently applied from our Resource Plan in Docket No. E002/RP-10-825. We will review other internal discussions as well as the Department of Commerce's position.

10. How will you roll out the electric vehicle static charging program, and how do you know who these electric vehicle customers are?

    Response: Load disaggregation is a way to identify the customers. Electric vehicles have a pretty distinct load. Additional ways include dealers or customers on electric vehicle rates such as the time of use. Customers can optimize their time of usage.

11. For the Peak Flex Credit, did Xcel Energy consider submitting a bid into the MISO stack?

    Response: Based on pricing in MISO, we wanted to design for future applicability.

[1] See Xcel Energy Reply Comments in Docket No. E002/M-20-421.
[2] See Attachment B, Chris Davis email dated November 12, 2020.

12. Why are you not connecting the incentive to net benefits to show value? Right now it looks like the proposed mechanism is an add-on cost to ratepayers without incentivizing yourself to perform better.

    Response: The avoided costs are variable, and in a changing system it introduces risk to the utility. That is why we requested a stakeholder group to look at future CIP incentive mechanisms. It has become variable enough to the Company that we have concerns about the lost opportunity cost, that being building more renewables. We can build more renewables or promote the most efficient use of that equipment. State policy through these Orders tells us what our regulators would like us to do and pursue. Within that Order, we are seeing an opportunity to make an investment in our capabilities to operate the system in a more dynamic way, but there has to be an earnings mechanism where the Company and shareholders can benefit while fully recognizing customer protections to ensure this is less expensive than building renewable resources. Recognizing that customer and Company objectives should be aligned, we are proposing that the value of net benefits be used as a cap on the incentive.

13. Do the costs shown include the incentive?

    Response: No, the proposed incentive is in addition to that.

14. At the cost of this portfolio, why not just install batteries?

    Response: We have not been able to get batteries through the cost effectiveness screening today. We are not counting them out, and see them as a part of this portfolio in the future. We expect to see the initial cost of this portfolio to become more efficient as time goes by.

III. Stakeholder Participant Expressed Positions

While we intended to determine and subsequently report stakeholder level of consensus/no-consensus and/or agreement/no-agreement on our proposed mechanism, there was no real level expressed either way. A stakeholder survey was planned, but unfortunately participants were unable to access it during the meeting. The survey was sent post-meeting and received four responses with almost half of the questions not answered. For these reasons, we will not be able to provide any insight to participant positions on the proposed measures or incentive mechanism.

IV. Participant Filing Recommendations

- Will costs be tied back to the Brattle study that found the 400 MW cost-effective?

  Response: Yes, this is still active in the Integrated Resource Plan (IRP).

- Will stakeholders be able to compare apples to apples across the Brattle study and across dockets?

  Response: Yes, we will gather the information in the filing and pull the dockets together to show how it connects.

- Would like to see the net benefits test, similar to Rhode Island, in the filing.

- Recommend including not only the cost and benefits for each test as well as the policy reason for each.

- Provide examples of a high level breakdown of a cost-effectiveness test.

- Main concern I see is the portfolio is focusing on sign-ups versus use. Need to add detail to the filing that shows how the products are going to be used, add future operational detail.

- Will you also discuss the possibility of doing more than 400 MW, sooner than 2023 at a cost equal to or lower than the Brattle cost-effective amounts? I know this goes above and beyond. This could include something like allowing aggregators to come in through a tariff (or something else).

- Explain how Xcel Energy works with aggregators in other states.

V. Next Steps

A Miscellaneous filing addressing the demand response financial incentive mechanism proposal will be submitted to the Commission for an anticipated summer 2021 launch. This filing serves to satisfy two Commission orders and support the achievement of a third order. The first is the anticipated order resulting from the September 17, 2020 Hearing in Docket No. E002/M-20-421 where the Company will be ordered to submit their demand response programs as part of a Miscellaneous

Filing versus including these efforts as part of an ongoing rate plan. The second is the Commission order in the PBR docket (Docket No. E002/CI-17-401) requiring the Company to propose an incentive mechanism for demand response activities. The third is the Commission's January 20, 2017 Order requiring the Company to acquire 400 MW of additional DR resources (Docket No. E002/RP-15-21). The filing will include products and measures that align with state, societal, customer and company objectives designed to provide customers with flexibility and the opportunity to increase sustainability.

CONCLUSION

Thank you for this opportunity to introduce and develop a proposal for a demand response financial incentive. We appreciate the time stakeholders have taken to engage in these discussions, as they have helped to shape the proposal.

Dated: November 24, 2020

Northern States Power Company

PERFORMANCE BASED RATEMAKING DEMAND RESPONSE INCENTIVE MECHANISM

Stakeholder Meeting #3

November 10, 2020

Xcel Energy®

Agenda

1. Introductions
2. Stakeholder Meeting Objectives
3. Stakeholder Meeting Process
4. Load Flexibility Plan
5. Incentive Mechanism
6. Product Proposal
7. Next Steps

Introductions

- Name
- Organization

Stakeholder Meeting Objectives

1. Follow Commission Order: *Establishing Methodologies and Reporting Schedules in Docket No. E002/CI-17-401 and dated April 16, 2020, Xcel Energy, in consultation with the Department and interested stakeholders will develop and file a Demand Response financial incentive for Commission consideration by the end of the first quarter of 2021.*

2. Follow the same transparent and collaborative stakeholder process utilized in the Performance Based Ratemaking (PBR) metric development.

3. In depth discussion of incentive mechanism and measures and presented to the stakeholder group in meetings 1&2.

4. Determine outstanding concerns, areas of consensus, areas of no consensus.

Stakeholder Meeting Process

October 6

- Review Objectives, History, Introduce Incentive Mechanism Options
- Summary report filed with Public Utilities Commission

October 20

- Stakeholder feedback & opportunity to bring forth new ideas
- Summary report filed with Public Utilities Commission

November 10

- Continued incentive mechanism discussion
- Determination of stakeholder positions, consensus building where possible
- Summary report filed with Public Utilities Commission

LOAD FLEXIBILITY PLAN

Load Flexibility Plan

Expansion of demand response to flexible load opportunities

Strengthen Customer Relationships

- Provide solutions to customers
- Flexible opportunities that can be altered as we learn from customers and systems
- Encourage adoption and deployment of new technologies
- Multi-year planning and budgeting

Costs and Benefits of flexible load

- Lower carbon emissions
- Optimized utilization of generation resources

Identify Barriers and Challenges

- Flexible opportunities that can be altered quickly
- We are trailblazing new efforts

Regulatory Alignment Discussion

- Preparing for the future

COST-BENEFIT ANALYSIS

Cost-Benefit Review

Proposed cost-benefit framework summary

- Societal test for screening of equipment acquisition
- Price Signal Test (RIM Test) and Participant Test used to balance rebates and bill credits between participants and total ratepayer base
  - Aligns with screening in Brattle Demand Response Potential Study

Avoided Carbon included in Societal and Price Signal Test

Based on hourly forecast system carbon emissions and environmental externalities [January 2018 Order Decision No. E999/CI-14-643 *Order Updating Environmental Cost Values]*

PROPOSED DR INCENTIVE – RECOMMENDATION AFTER FEEDBACK

Proposed Incentive

Rate of Return based on MW achievement (5% to 15%) – No amortization/capitalization

- Goal MW for 2021-2023 on path to meet 400 MW requirement
- % of expenses award below goal to cover portion of lost opportunity disincentive (5% to 10% of spend from 50% to 100% of filed goal MW)
- % of expenses award above goal to incentivize cost-effective achievement (10% to 15% of spend from 100% to 150% of filed goal MW)
- Earnings tied directly to MW achievement (performance)
- Utilizing expenditures vs multi-year amortizations removes some complexity and incentive growth in future years
- Cost effectiveness criteria prevents spending just to increase incentive

	2017 Actual	2018 Actual	2019 Actual	2020 Forecast	2021 Forecast	2022 Forecast	2023 Forecast
Total Controllable Load	851	824	897	920	970	1,147	1,304
Cumulative Incremental Load	0	-27	46	69	119	296	453

Demand Response Incentive Mechanism Comparison

	Michigan	Rhode Island	Minnesota (proposed)
Type of DR	Shed	Shed	Shed, Shift, Shape
Goal	369 MW (2019)	14 - 20 MW (2019) 17 – 24 MW (2020) 20 – 29 MW (2021)	9 MW (2021) 24 MW (2022) 41 MW (2023)
Incentive Mechanism	% of spend on sliding scale	% of net benefits	% of spend on sliding scale
Minimum achievement required for incentive	50% of goal	14 MW (2019) 17 MW (2020) 21 MW (2021)	50% of Goal
Max available incentive	20% of O&M spend (2018) 15% of O&M spend (2019) (if 150% of goal achieved)	45% of the net benefits up to MW max goal	15% of O&M spend (if 150% of goal achieved)
Annual DR Budget (actual and *estimate*)	$10,400,000 (2018) $16,300,000 (2019)	N/A	*$3,200,000 (2021)* *$6,000,000 (2022)* *$7,000,000 (2023)*
Incentive (actual and *estimate*)	$2,026,943 (2018) $2,446,817 (2019)	$362,085 (2019) *$622,000 (2020)* *$944,000 (2021)*	*$320,000 - $480,000 (2021)* *$600,000 - $900,000 (2022)* *$700,000 - $1,050,000 (2023)*

Proposed Incentive

Cap Incentive on Price Signal Test (RIM Test) beginning in 2023

- 2021 and 2022 include significant upfront administration costs and rebates for long-lifetime equipment acquisition measures
- Costs may cause Price Signal Test to fail in 2021 and 2022
- 2023 represents better long-term effects with significant on-going demand response participation
- Ensures Demand Response Portfolio with Incentive is cost-effective to customers long term
- Allowing incentive to begin in 2021 encourages the Company to make necessary investments for successful products

PRODUCT PROPOSAL

Draft Executive Summary

Program	MW's	2021 Budget	2022 Budget	2023 Budget	Total Budget
Residential Offerings					
Static EV Charging Optimization	1.2	$ 371,128	$ 348,384	$ 573,12[illegible]	$ 1,292,634
Strategic Electrification -Smart Heat Pump Water Heater -Air Source Heat Pumps -Mini-Split Heat Pumps	0.04	$ 552,214	$ 959,986	$ [illegible],391,[illegible]58	$ 2,903,458
Residential Total	**1.24**	**$ 1,023,342**	**$ 1,463,370**	**[illegible] 2,16[illegible],390**	**$ 4,656,102**
Commercial Offerings					
Peak Flex Credit	36.1	$ 656,000	$ 1,438,0[illegible]0	$ 2,277,000	$ 4,371,000
Business Load Shifting (Refrigeration & Cooling)	3.2	$ 412,000	$ 824,0[illegible]	$ 1,236,000	$ 2,472,000
Static EV Charging Optimization	TBD	TBD	[illegible]BD	TBD	$ -
Excess Supply Program	0	$ 100,000	$ 155,0[illegible]	$ 205,010	$ 460,010
Commercial Total	**39.6**	**$ 1,168,000**	**$ [illegible]417,0[illegible]0**	**$ 3,718,010**	**$ 7,303,010**
R&D					
Electric Vehicle – School Bus Charging Pilot	0.3	-	$ 148,000	$ 138,000	$ 286,000
Additional R&D		$ 1,000,000	$ 2,000,000	$ 1,000,000	$ 4,000,000
R&D Total	**0.6**	**$ 1,000,000**	**$ 2,148,000**	**$ 1,138,000**	**$ 4,286,000**
Total Filing Request	***41.44***	***$ 3,191,342***	***$ 6,028,370***	***$ 7,025,400***	***$ 16,245,112***

Residential Offerings

Focus on moving towards load shifting and beneficial electrification

Static EV Charging Optimization

- Customer receives an incentive for EV charging outside of on-peak periods
- Customer sets schedule using Xcel Energy determined charging window based on driving requirements
- Targets residential and light-duty fleet vehicles that are not on time-varying rate

Strategic Electrification

- Equipment incentives for smart heat pump water heaters, air source heat pumps, mini-split heat pumps
- Control incentive for participating in load shifting demand response
- *Note: Does not include funding for testing other load shifting DR*

Commercial Offerings

Focus on offering flexibility and increasing future load relief

Peak Flex Credit (Pilot)

- Interruptible rate offering several choices to meet customer needs (summer vs. all year, etc.)
- Economic and Emergency Control
- Pricing based on MISO impacts

Business Load Shifting (Refrigeration and Cooling)

- Incentives for adjusting the timing of equipment usage

Static EV Charging Optimization

Excess Supply Program (Pilot)

- Incentives for utilizing energy during times of renewable excess

R&D

Funding to allow testing, review and quick modification to adjust to market conditions

- Pilot to test the usage of charging electric buses on off-peak times
  - Scheduled to begin in 2022
  - Analyze the cost effectiveness of the program
- Additional funding to review further residential control strategies under differing conditions and research on cost benefits of load shifting.

PARTICIPANT FEEDBACK


Xcel Energy®

From: Davis, Christopher (COMM)
To: Gottschalk Syvertsen, Crystal L; apartridge@mncee.org; gstaples@mendotagroup.com; DeBleeckere, Tricia (COMM); mbull@mncee.org; commerce.attorneys@ag.state.mn.us; davedahlberg@nweco.com; jfarrell@ilsr.org; Ferguson, Sharon (COMM); katherine@aem-alliance.org; annielf@cubminnesota.org; gmiller@dakotaelectric.com; kmunsch@citizensutilityboard.org; rnordstrom@gpisd.net; OTPRegulatory@otpco.com; residential.utilities@ag.state.mn.us; dscott@gpisd.net; Seuffert, Will (PUC); psharkey@environmentallawcounsel.com; jstrommen@kennedy-graven.com; jzethmayr@citizensutilityboard.org; tdrake@gpisd.net; Martone, Kelly (PUC); will@votesolar.org; stacy.miller@minneapolismn.gov; sara.bergan@stoel.com; gleckner@fresh-energy.org; jjellings@gpisd.net; johnson@fresh-energy.org; Kundert, John (COMM); klee@mncenter.org; wmurray@rstreet.org; ksullivan@gpisd.net; chris@pluggedinstrategies.com; joseph.meyer@oag.state.mn.us; Dockter, Bridget N; Harris, Matt B; Petersen, Jeremy A; jessica.k.peterson@xclenergy.com; White, Shawn M; Schwain, Kevin D; Bjork, Thor S; Doyle, Brian G; Burdette, Jessica (COMM); JHarmon@misoenergy.org; rmerring@misoenergy.org; cwinton@mnchamber.com; lcurrie@mncenter.org; Bael, David (MPCA); Stalpes, Sean (PUC); ckunkle@windonthewires.org; Ryan.Hledik@brattle.com; ingrid@bjorklundlaw.com; Brian.Millberg@minneapolismn.gov; Brian Edstrom; Alison Archer; davenwec@gmail.com; Katherine Hamilton; Isabel Ricker; Mcfarlane, Ashly A; Andrew Twite; Peterson, Jessica K
Cc: Dockter, Bridget N
Subject: RE: Performance Based Ratemaking Demand Response Stakeholder Meeting 3 of 3
Date: Thursday, November 12, 2020 4:12:32 PM
Attachments: MISO 2019 Marginal Units.pptx

EXTERNAL - STOP & THINK before opening links and attachments.

Afternoon folks

Attached is a PowerPoint the Department (Dr. Rakow) developed to present its earlier analysis of what generation units have been on the margin in MISO. As you will see, more than one unit has been on the margin, especially in 2017. The PowerPoint includes data analysis 2017-2019. I tried to attach a workbook that includes additional data from 2020, but its inclusion made the email to large to send to most recipients. Let me know if you're interested and I could try sending it individually, or at least the figures/charts from the data.

The Department provides this analysis to indicate the most likely impact of creating new load through EVs. Contrary to the assumption that renewables are the generation resource most on the margin at night, coal and natural gas are. Any analysis of changes in CO2 emissions must take actual MISO marginal resource emissions into account. This analysis does not mean that Minnesota should not proceed with promoting EVs to reduce carbon and other emissions. It does mean that for the foreseeable future, however, that the carbon emission reductions are not as high for EVs as if a utility's average emissions profile is used. And it has repercussions for the cap that Xcel proposes for its demand response incentive mechanism. Emission reductions assumed for EVs will increase as the marginal units on MISO have lower carbon emissions and when EV load grows enough to require that a utility needs to add additional resources, most likely renewables.

How does a generating unit become marginal?

1. There are limits to the amount of power that can be exported from MISO north.
2. When (MW supply in MISO north) > (MISO north demand + MISO north export capability) some generators will have to ramp down.
3. To get the ramp down, MISO's system calculates a negative marginal cost of congestion; reducing the overall LMP.
4. The first units to respond to lower LMPs (ramp down) will be the highest cost units (gas/coal).
5. Nuclear generating units would be next, but historically they've had little ability to ramp. (That might be changing now).
6. Eventually, through the LMPs, MISO ramps down so much generation that zero cost units (hydro and wind w/out PTCs) are on the margin. Wind and hydro are both dispatchable in MISO's world so they ramp down.

The Department continues to support a marginal emissions analysis when evaluating changes in carbon emissions due to an increase in the use of EVs, as recommended in *Beneficial Electrification: Ensuring Electrification in the Public Interest*, Regulatory Assistance Project, June 2018 publication, page 55. https://www.raponline.org/knowledge-center/beneficial-electrification-ensuring-electrificationpublic-

On page 55 of Beneficial Electrification, the Regulatory Assistance Project states:

> **Marginal emissions analysis**: This shows, in aggregate, the emissions from the generation resource on the margin in a specific balancing area, meaning the emissions that would be produced to meet an additional increment of load. This should be hourly data, available from the system operator, that can be used to assess how emissions will vary over all the hours of the year and from year to year in response to permanent load changes. <u>This approach provides the most accurate and useful information for policymakers to determine a system's marginal emissions and the impacts of electrification.</u> *Emphasis added*

Thanks for letting me share.
Chris

MISO Generating Units Operating on the Margin

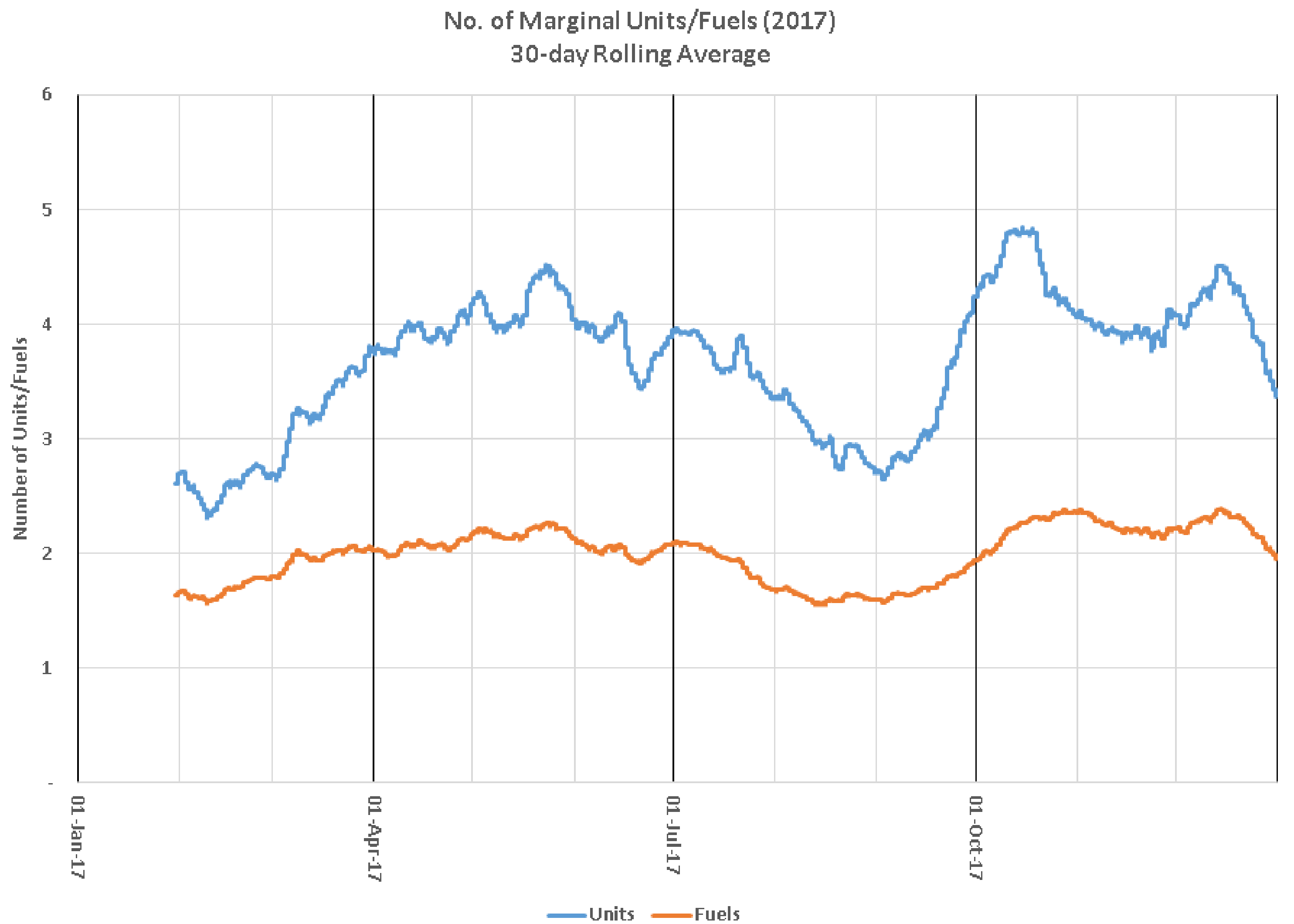
Electric Vehicles and Utilities

Defining a Marginal Unit

- In electricity, supply must equal demand in real time.
- The marginal unit is the power plant that is ramping up and down so that supply equals demand. Sometimes more than one unit is marginal.
- The marginal fuel is the fuel used by the marginal unit.

In 2017:

- Usually there were 2 fuels on the margin;
- Usually there were 3 – 4 units on the margin;
- **Both indicate persistent congestion**.

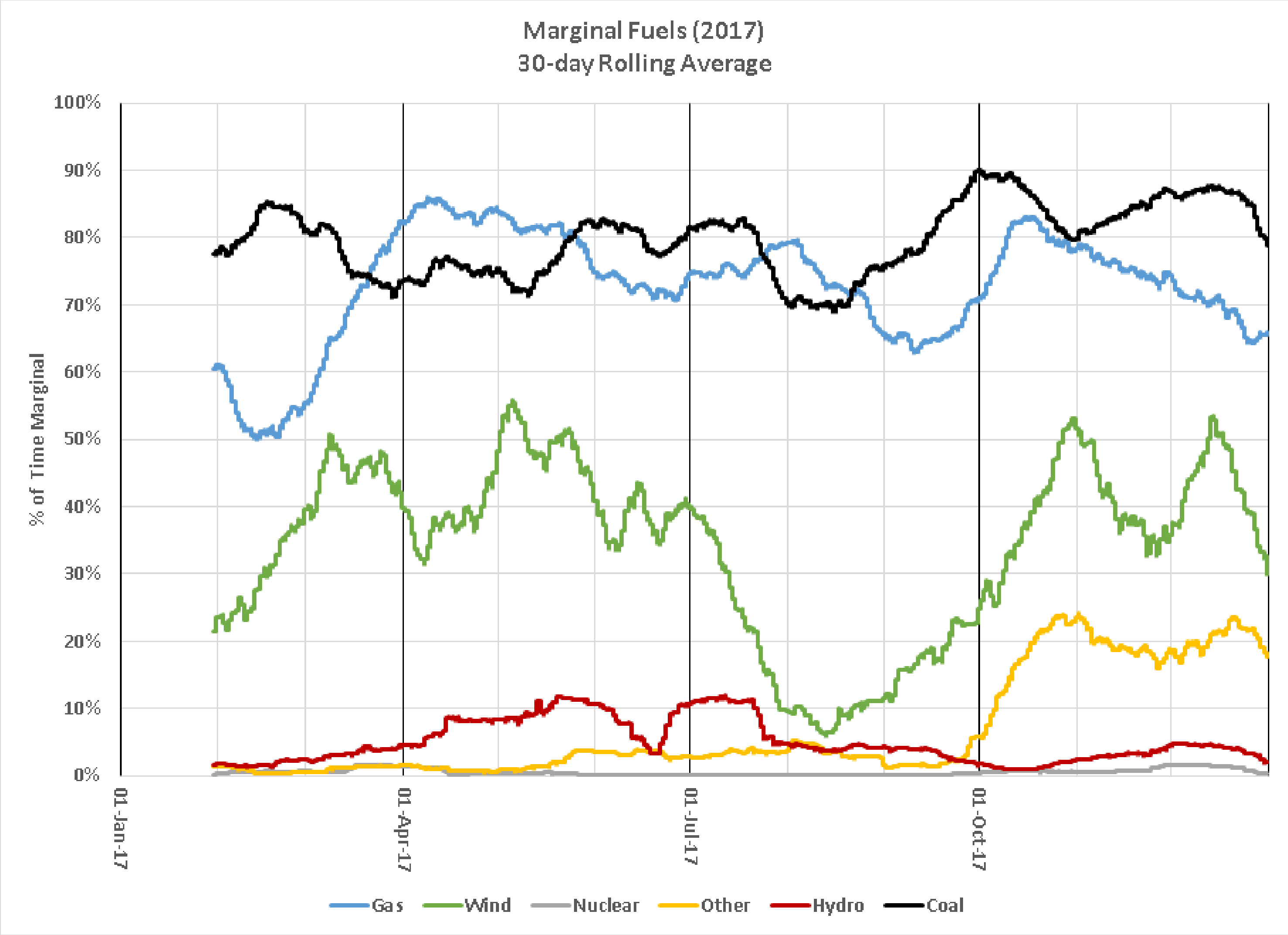


In 2017:

- Coal is marginal 70 – 90% of the time;
- Gas is marginal 60 – 85% of the time;
- Wind is marginal 30 – 50% of the time (except summer); and
- All other fuels infrequently marginal.

NOTES:

- Numbers add up to >100% because multiple fuels are on the margin (see prior slide).
- Since wind's marginal cost is low (or negative—PTC) and the marginal unit sets the price, wind as marginal indicates low or negative LMPs somewhere.

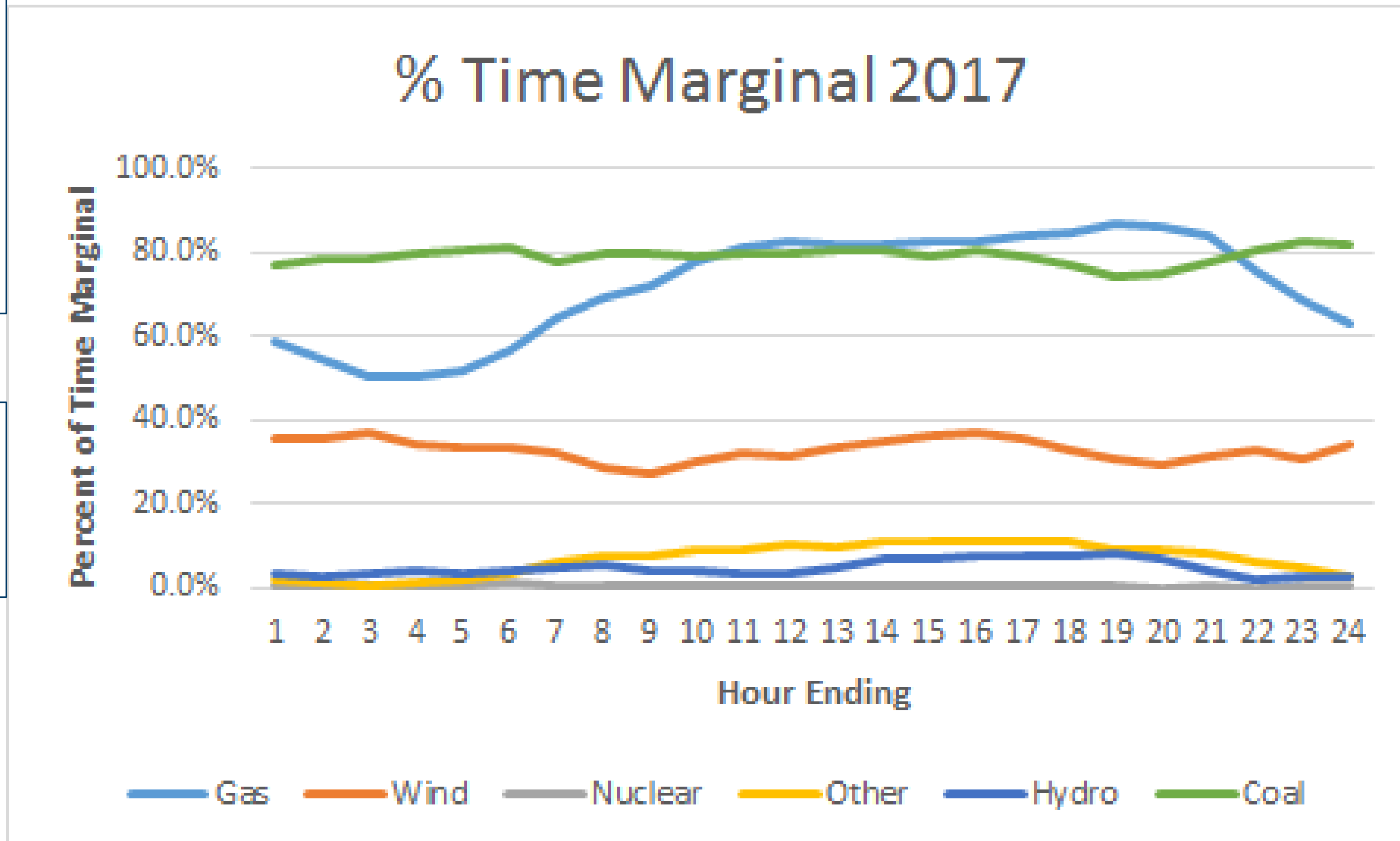


In 2017, for a typical day:

- Coal is marginal 80% of the time regardless of time of day;
- Gas marginal more often on-peak than off-peak;
- Wind is similar in all hours;
- All other fuels infrequently marginal.

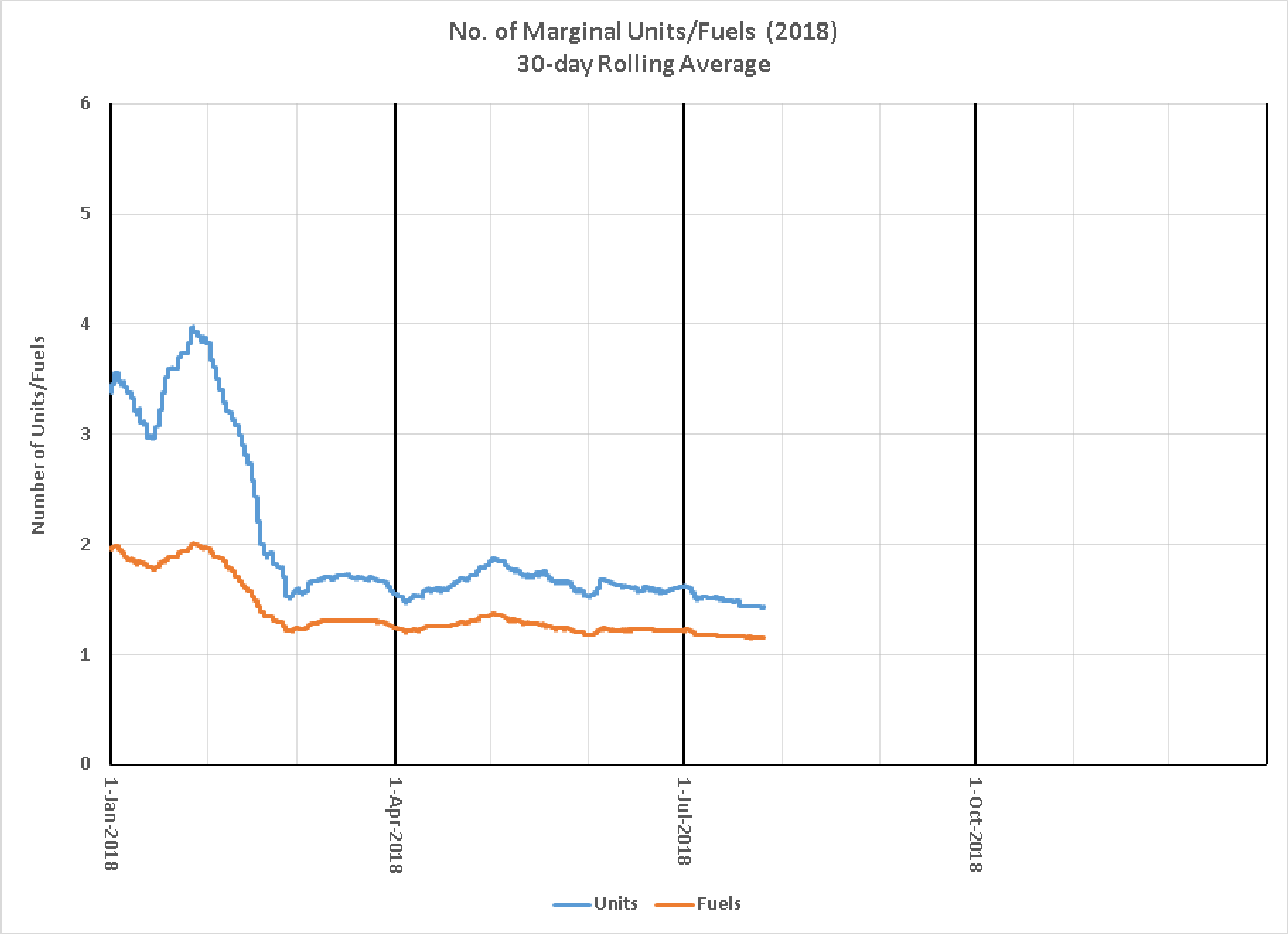
NOTES:

- Numbers add up to >100% because multiple fuels are on the margin.



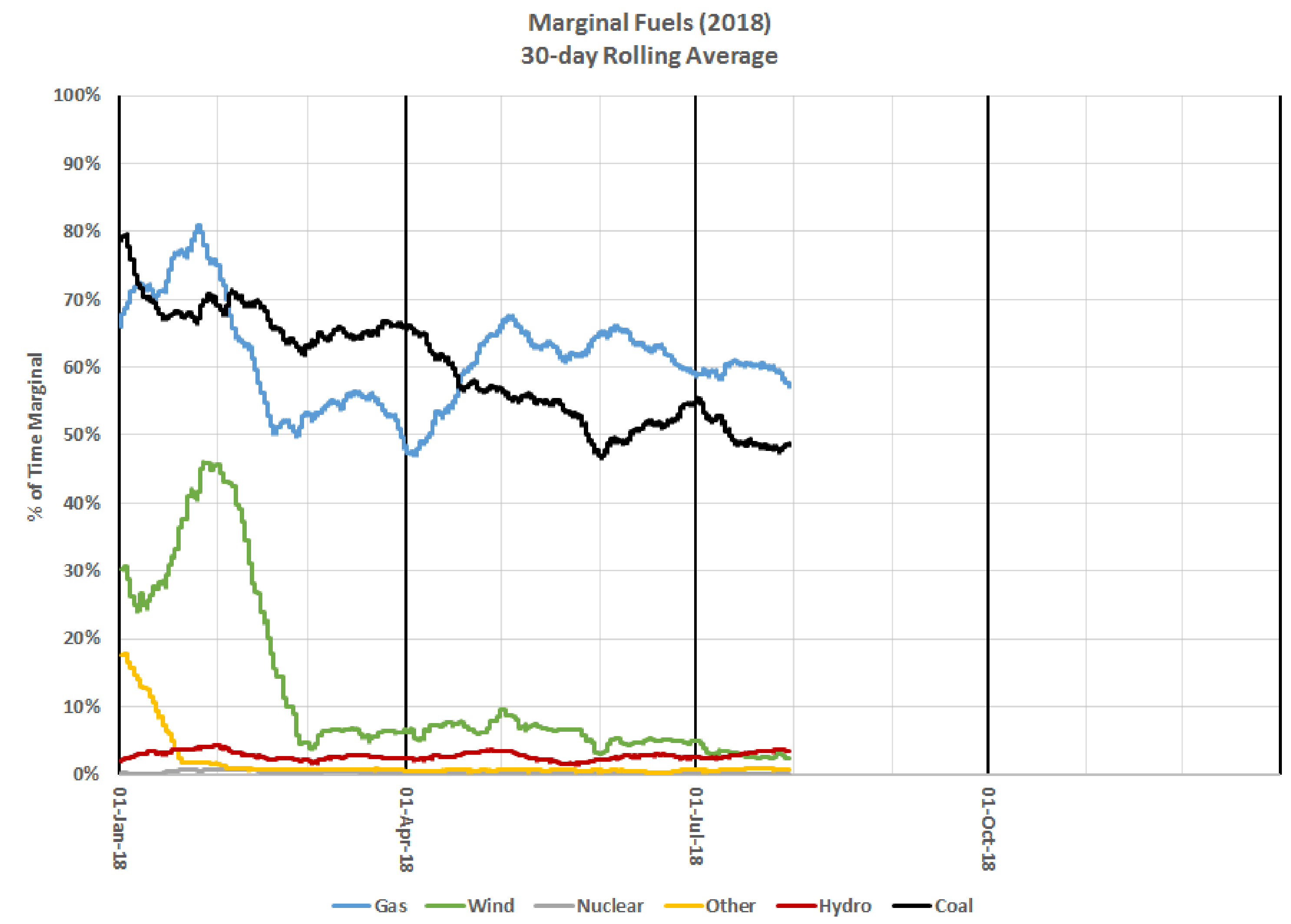
In 2018:

- The year started resembling 2017 (through January);
- From February average number of marginal units dropped from 4 to 1.5; and
- From February average number of marginal fuels dropped from 2 to 1.15.
- **This indicates a significant drop in congestion.**



In 2018, after January:

- Coal is marginal 50 – 70% of the time;
- Gas is marginal 50 – 70% of the time;
- Wind is marginal < 5% of the time; and
- All other fuels infrequently marginal (< 5%).

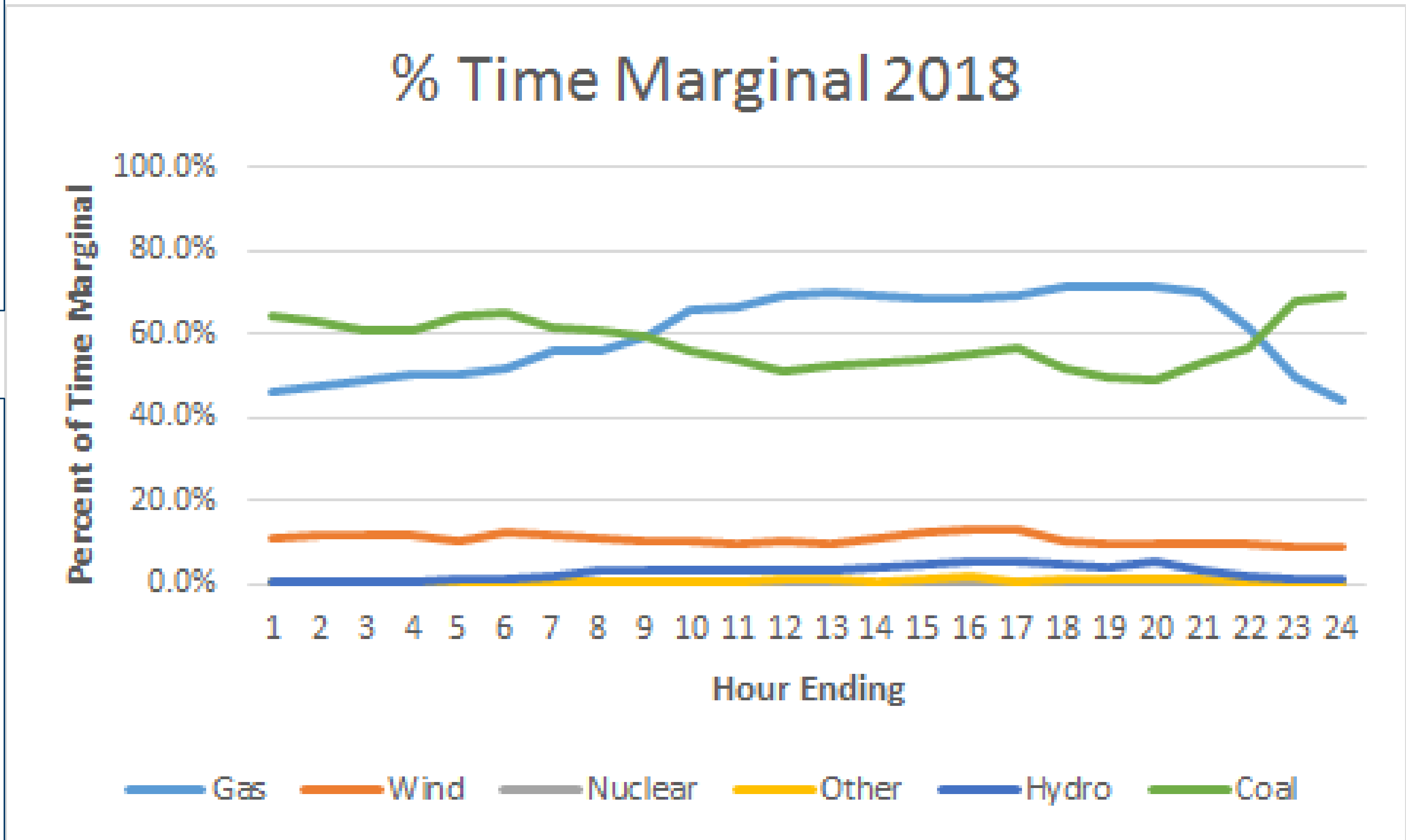


NOTES:

- Numbers add up to >100% because multiple fuels are on the margin (see prior slide).
- Percent of Time Marginal now resembles expectations:
  - wind rarely marginal due to low cost; and
  - Gas and Coal frequently marginal.

In 2018, for a typical day:

- Coal is most common marginal fuel off-peak;
- Gas is most common marginal fuel on-peak;
- Wind is similar in all hours;
- All other fuels infrequently marginal (< 5%).



NOTES:

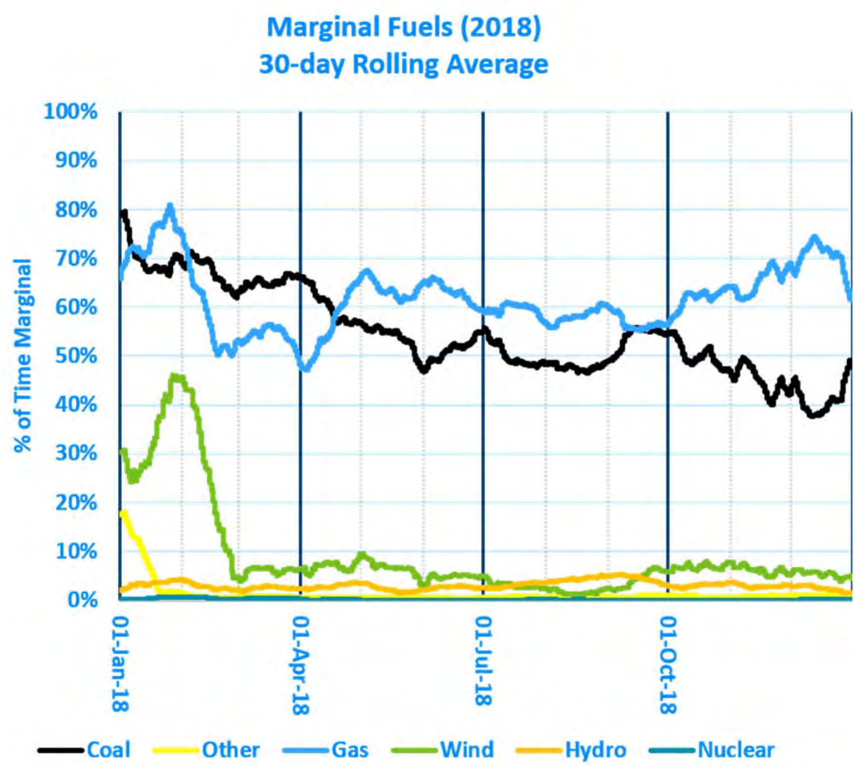
- Numbers add up to >100% because multiple fuels are on the margin (see prior slide).

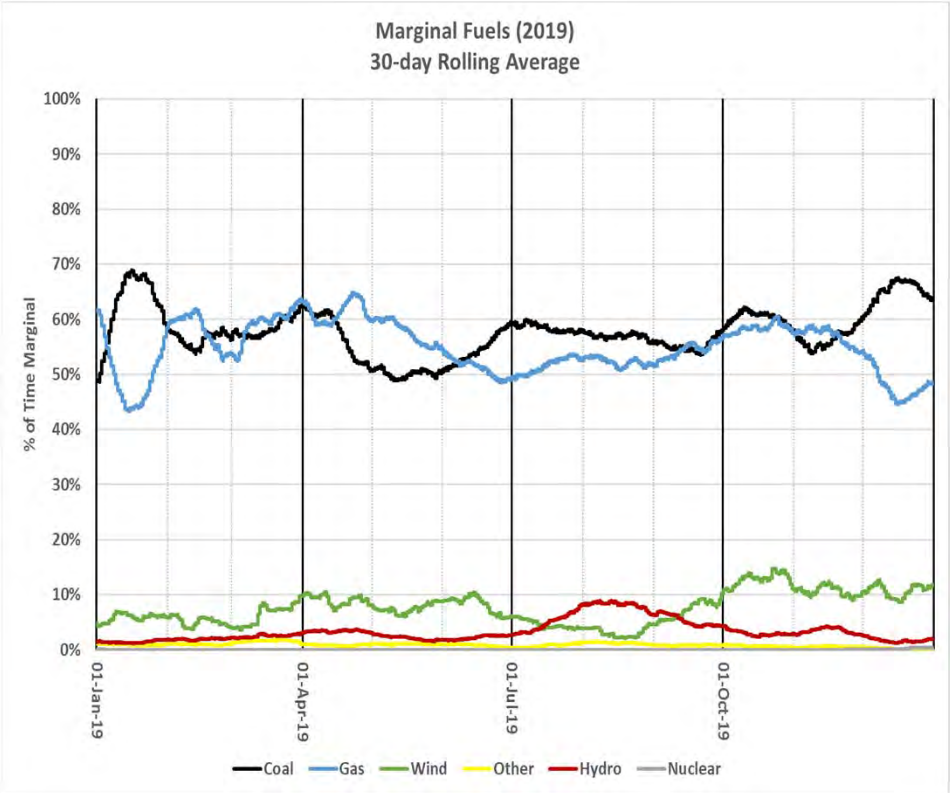
- Percent of Time Marginal now resembles expectations:
    - wind rarely marginal due to low cost; and
    - Gas and Coal marginal related to time of day.

Marginal Unit Summary

- Will the future resemble 2017 (3+ marginal units/fuels) or 2018 (usually 1 – 2 marginal units/fuels)?
- For now, coal and gas are typically the marginal fuels.
- Wind should only be marginal if there is significant congestion.

2019 MISO Marginal Fuels

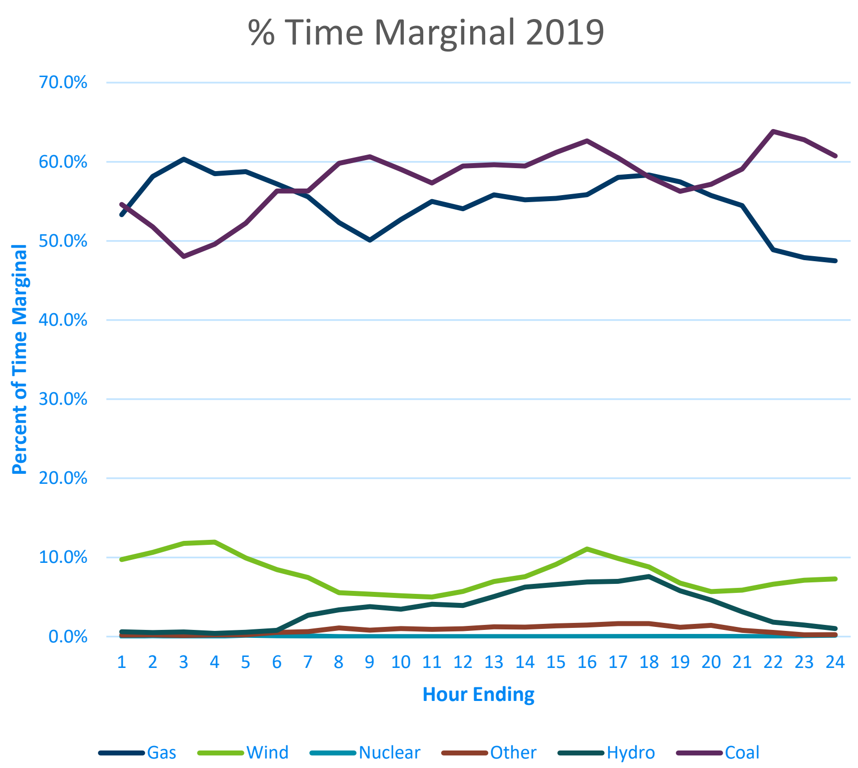


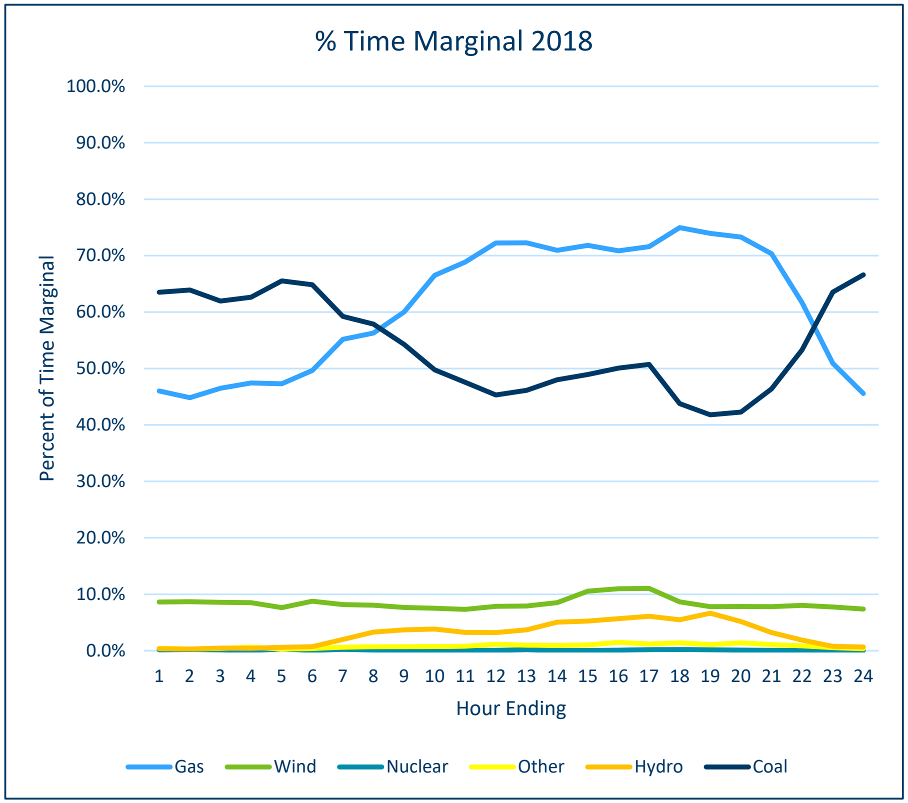


Comment on Marginal Fuels

- Marginal fuels were very similar in 2018 and ‘19.
- Coal and gas are the main marginal fuels.
- Wind and hydro are rarely a marginal fuel.

2019 Marginal Fuels by Time of Day





Attachment F

Summary
Utility Performance Dashboard
Stakeholder Meeting

March 2, 2021

STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

Katie Sieben	Chair
Joseph K. Sullivan	Vice-Chair
Valerie Means	Commissioner
Matthew Schuerger	Commissioner
John Tuma	Commissioner

IN THE MATTER OF THE COMMISSION INVESTIGATION TO IDENTIFY AND DEVELOP PERFORMANCE METRICS AND POTENTIALLY, INCENTIVES FOR XCEL ENERGY'S ELECTRIC UTILITY OPERATIONS

DOCKET NO. E002/CI-17-401

UTILITY PERFORMANCE DASHBOARD SUMMARY STAKEHOLDER MEETING

INTRODUCTION

Northern States Power Company, doing business as Xcel Energy (the Company), submits to the Minnesota Public Utilities Commission (Commission) this Meeting Summary Report in accordance with the Minnesota Public Utilities Commission's April 16, 2020 ORDER ESTABLISHING METHODOLOGIES AND REPORTING SCHEDULES in the above-noted docket.

Ordering Paragraph No. 1(e) instructed Xcel Energy to:

> *in direct consultation with interested stakeholders, shall explore and develop options to employ an online utility performance dashboard and present those options to the Commission in the first annual report, including a fair discussion of the costs involved*

On February 9, 2021, the Company served notice of a stakeholder meeting to discuss utility performance dashboard options in the instant docket. The intent of the meeting was to comply with the Commission's Order, follow the same transparent and collaborative stakeholder process utilized in the Performance Based Ratemaking (PBR) metrics development in the present proceeding, and provide and discuss information on existing online utility performance dashboards and known costs. Performance based rates and associated metrics are, at this point, utilized minimally around the country. However, we brought forward the information we were able to find for discussion to this stakeholder group.

While not required as part of the Commission's Order, we provide this summary of the utility performance dashboard meeting conducted on March 2nd, 2021 for transparency of process. The format of the meeting was via online Teams. A PowerPoint was sent to attendees prior to the meeting and is included as Attachment A to this report.

Participants included:

Participant	Organization	Participant	Organization
Brian Edstrom	Citizens Utility Board	Riley Conlin	Stoel Rives
Joe Meyer	OAG-RUD	Grey Staples	The Mendota Group
John Kundert	Dept of Commerce	Mike Bull	Ctr for Energy & Env
Joe Sathe	Suburban Rate Authority	Kelly Martone	Public Utilities Comm
Audrey Partridge	Ctr for Energy & Env	Nick Paidosh	Xcel Energy
Crystal Gottschalk	Xcel Energy	Mary Martinka	Xcel Energy
Bridget Dockter	Xcel Energy		

The remainder of this summary is organized as follows:

- Section I discusses the sample information we found of utilities reporting performance metrics through annual regulatory filings, uploaded to their respective regulator websites;
- Section II describes the groups discussion around sample online dashboard options, one hosted at the utility website and one hosted at the regulator website;
- Section III addresses an Xcel Energy online dashboard development options and the subsequent discussion.

I. UTILITY ANNUAL PERFORMANCE METRIC FILINGS

To ground the discussion, we introduced utilities that produce annual metric reports, including charts and graphs, and upload them to their respective regulator websites similar to Minnesota's eDockets. We reviewed reporting and formatting of Illinois utilities Commonwealth Edison (ComEd) and Ameren, Massachusetts utility National Grid, and California Utilities Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric. Although the California utilities have metrics, we were unable to find them on the California Public Utilities Commission or the individual utilities website(s).

<u>Q&A</u>
No clarifying questions were asked by attending parties at this time.

II. UTILITY / REGULATOR ONLINE DASHBOARD OPTIONS

The Company reviewed two active online dashboards with differing hosts. One dashboard option was hosted by Hawaiian Electric Company (HECO) and the other hosted by a regulator, the Ontario Energy Board (OEB). HECO's website is probably the most well-known and comprehensive online dashboard example and we've talked about it a few times within the PBR workgroup. We met with the regulatory and website management group to learn about its development and functionality. The performance metric portion of the website was born out of a decoupling settlement, therefore, they did not know the specific development costs associated with the PBR development itself. However, they do estimate annual maintenance – that includes staff resources as this is very manual for them to be approximately $240,000. HECO's version is a simplified option of subject matter experts providing verified and approved data at monthly intervals on an excel spreadsheet, the data is then moved to Microsoft word and published to their website. The data can be viewed in charts and graphs, as well as historical.

The Ontario Energy Board (OEB) is the regulator of 66 Canadian distribution utilities and metric reporting is all hosted on the OEB's website. The OEB's online PBR metric dashboard provides a variety of views from individual utility to a comparison of certain items for all reporting utilities. Utilities report their information to the OEB and OEB creates the public facing dashboard – so there are labor costs involved for the regulator to manage the tool and compile the comparison data. While each utility reports the "metrics" themselves, they are each provided the opportunity to supplement the data with "discussion and analysis". We could find no cost estimates or allocations.

<u>Q&A</u>

1. Do any ratepayers actually visit the dashboard?
   <u>Response:</u> When we met with HECO, they stated they found value in the ability to direct both external and internal parties to accessible reports, [but they did not mention that they tracked website visits].
2. One party suggested the Commission host the dashboard.
   <u>Response:</u> Early in this docket the Company completed data requests the provided very high level costs of company versus commission housed dashboard. It should be noted that these estimates where prior to the final metric approval and costs would be different. We would, however, have the same concerns with cyber security we had included in our original response. Depending on what kind of structure was requested, the cost and depth of work would like change significantly.
3. <u>Comment:</u> Some parties did not believe HECO's website PBR metrics were user friendly.

4. <u>Comment:</u> A party was not in favor of providing a comparative analysis of multiple utilities as each have their own customer and geographic make-up.
5. Are there any known Out of Box software options to consider?
   <u>Response:</u> A presenter at the last in-person NARUC conference mentioned a software option. Parties cannot find the option at this time.

III. XCEL ENERGY DASHBOARD DEVELOPMENT OPTION(S)

Cost estimates to develop an online metric dashboard using Xcel Energy's website were provided to the stakeholder group and vary significantly, but without knowing more of what we are looking at, it is incredibly difficult to come up with a more concise estimate at this point. A more cost friendly approach that appears to be user friendly is the HECO online dashboard style. Using this approach, the subject matter experts pull, verify, and upload their information in a Microsoft Excel spreadsheet. Next, the website management team transfers to Microsoft Word and uploads to pre-set graphs and links on the Company's website. We estimate this would fall into the approximate range of $125,000 to develop (depending on the requested criteria and capabilities) with annual maintenance of approximately $200,000.

If we consider building something much more extensive that was automated and/or tied into the Commissions website, it would be on the higher cost range with an estimate that may meet $1.5M. Development and maintenance costs are dependent on the extensiveness, capabilities, automation, and cyber security measures required of the dashboard interaction.

<u>Q&A</u>

1. Does Xcel Energy track this data (approved PBR metrics) now in spreadsheets?
   <u>Response:</u> Different data is available on different systems, it is not all in one place.
2. Has anyone identified who the different audiences are? Perhaps poll customers to determine what they are interested in seeing?
   <u>Response:</u> Xcel Energy has not done that. No comment from parties as to whether of not anyone else has.
3. <u>Comment:</u> Possibly consider custom reports to customers, with costs to be covered by the requestor. Would allow customers to examine why they may have had multiple outages.
   <u>Response:</u> This is more than the simplified version we have been discussing. This option may have data privacy considerations and may be tied into more extensive reporting costs. Some parties agreed this was a concept to bring up in the data privacy docket.
4. If a full dashboard platform is developed (closer to the $1.5M estimate), would it bring down the annual maintenance costs of $200,000?

Response: There may be some efficiencies gained with the full automation since much of the other option is manually labor based.

IV. Next Steps

The stakeholder group decided it would be valuable to be able to visualize an illustrative example of a prioritized online scorecard/dashboard, utilizing the Commission's approved five Outcomes of: affordability, reliability, customer service quality, environmental performance, and cost-effective alignment of generation and load. The illustration will include some of the associated metrics under these outcomes and will be split to the best of our ability into residential and commercial. The illustration will not include all 17 approved metrics, but items we believe at this time may be of most importance to our customers, offering a simplified view and approach. We will include the illustration in our first annual report filing April 30, 2021.

Conclusion

Thank you for this opportunity to discuss an online performance metric dashboard in conjunction with stakeholder input. We look forward to further discussions.

Dated: March 10, 2021

Northern States Power Company

PERFORMANCE BASED RATEMAKING: DASHBOARD

Stakeholder Meeting

March 2, 2021

AGENDA

1. Introductions
2. Meeting Objectives
3. Performance Based Ratemaking Metric Reporting Options
4. Utilities with Regulatory Reporting
5. Utilities/Regulators with Dashboards
6. Xcel Energy Dashboard Development Option
7. Other Considerations
8. Next Steps

Introductions

- Name
- Organization

Stakeholder Meeting Objectives

1. Follow Commission Order: *In accordance with the Commission's Order Establishing Methodologies and Reporting Schedules in Docket No. E002/CI-17-401 and dated April 16, 2020, Xcel Energy, in direct consultation with interested stakeholders, shall explore and develop options to employ an online utility performance dashboard and present those options to the Commission in the first annual report, including a fair discussion of the costs involved (Order Point 1.e.).*

2. Follow the same transparent and collaborative stakeholder process utilized in the Performance Based Ratemaking (PBR) metric development.

2. Discuss online utility performance dashboard options and known costs.

3. Compile discussion points and options to submit in PBR annual report April 30, 2021.

Performance Based Ratemaking Metric Reporting Options

Utilities with Regulatory Reporting Requirements	Utilities / Regulators with Dashboards	Xcel Energy Dashboard Development Option	Other Pre-Built Software Options to Explore?

UTILITIES WITH ANNUAL REGULATORY REPORTING

- Commonwealth Edison (ComEd) & Ameren - Illinois
- National Grid - Massachusetts
- Pacific Gas & Electric, Southern California Edison, and San Diego Gas & Electric - California

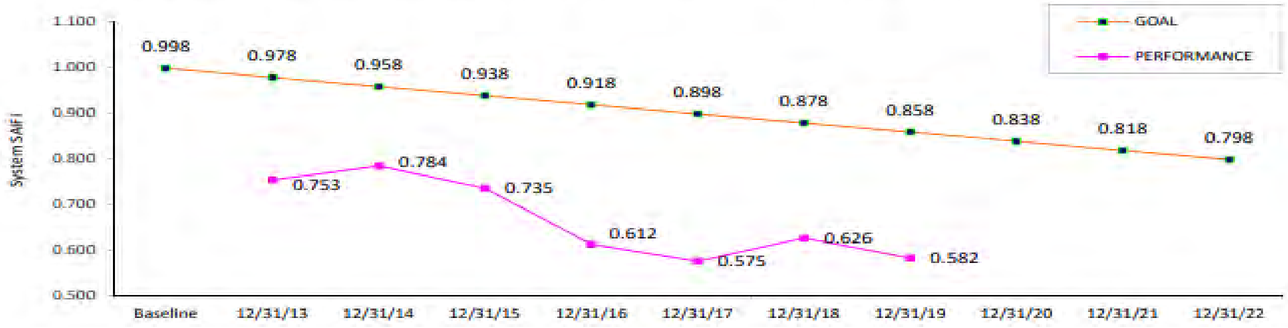
ComEd Example

Performance Year 7 Actual Performance. For Performance Year 7, ComEd's annual performance goal for System SAIFI was 0.858. As reflected in Table 1 and Chart 1, ComEd's performance of 0.582 achieved the Performance Year 7 goal.

TABLE 1: SYSTEM SAIFI ANNUAL GOALS & PERFORMANCE

YEAR	SYSTEM SAIFI ANNUAL GOAL	SYSTEM SAIFI ANNUAL PERFORMANCE
	(average number of interruptions per customer)	
Baseline (2001-2010)	0.998	
1/1/13 – 12/31/13	0.978	0.753
1/1/14 – 12/31/14	0.958	0.784
1/1/15 – 12/31/15	0.938	0.735
1/1/16 – 12/31/16	0.918	0.612
1/1/17 – 12/31/17	0.898	0.575
1/1/18 – 12/31/18	0.878	0.626
1/1/19 – 12/31/19	0.858	0.582
1/1/20 – 12/31/20	0.838	
1/1/21 – 12/31/21	0.818	
1/1/22 – 12/31/22	0.798	

CHART 1: SYSTEM SAIFI ANNUAL GOALS & PERFORMANCE



https://www.icc.illinois.gov/industry-reports/comed-performance-metrics

National Grid Example

Massachusetts Electric Company
Nantucket Electric Company
each d/b/a National Grid
D.P.U. 20-68
Exhibit NG-12
H.O. ___________
Page 1 of 2

Summary of Scorecard Metrics					
Metric	**Measure**	**Description**	**Source**	**Time Period**	**Baseline**
GHG Emissions Reduction	GHG Emissions Reduction	Reduction in the annual GHG emissions of the Company's electric operations, including electric transmission and distribution operations, property and transportation fleet, by 10% (or 4,449 metric tonnes CO2e cumulative) by 2024	Company	2017	44,495 metric tonnes CO2e
Customer Engagement	Customer Adoption of Digital Bill Pay	Number of successful digital channel payment transactions as a percentage of transactions across all engagement channels	Company/ Western Union	Aug 2017 - Jul 2018	24%
	Web User Experience Index	1 to 100 score on a web-based survey that assesses the customer's experience with the Company's website in six areas: functionality, usability, intelligence, performance, engagement, and visual design	AnswerLab	Oct 2017 - Sept 2018	59
	First Contact Resolution	Percentage of customer issues that are resolved by a customer representative on the first contact	Company	Aug 2017 - Jul 2018	72%
	Average Speed of Answer	Average length of time it takes for a customer representative to answer a customer once they have dropped off the automated system	Company	Oct 2017 - Sept 2018	107
DER Customer Experience	DER Customer Adoption of e-signature	User adoption rate of the e-signature feature on nCAP portal (%)	Company	May 2018 - Apr 2019	3%
	DER Customer Adoption of e-payment	User adoption rate of e-payment feature on the nCAP portal (%)	Company	May 2018 - Apr 2019	77%
	DER Customer Inquiry Response Time	Average number of days to answer a DER customer inquiry (# of days)	Company	May 2018 - Apr 2019	7
	Authority to Interconnect	Conversion rate of project applications to authority to interconnect (%)	Company	May 2018 - Apr 2019	73%

https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/12245274

Utilities / Regulators with Dashboards

Hawaiian Electric Company (HECO)

- Utility to ~1.33M customers
- Most comprehensive example
- Updates completed in Excel spreadsheet, moved to Word, published to website
- Estimated development cost: unknown
- Estimated annual cost: $240k[1]

Ontario Energy Board (OEB)

- Regulator of 66 distribution utilities
- Hosted on the OEB website
- Provides 1-page scorecard of metrics for a 5-year period
- Can view individual utility or all for many metrics
- Scorecard is supplemented with “discussion & analysis” for each metric
- No cost estimates

1. PUC-HECO IR 30, Docket No 2018-0088

Hawaiian Electric

https://www.hawaiianelectric.com/about-us/key-performance-metrics

Ontario Energy Board

https://www.oeb.ca/_html/performance/report_builder_display.php?reportyear=2019&custom=on

Custom Performance Report (Reporting Year: 2019)

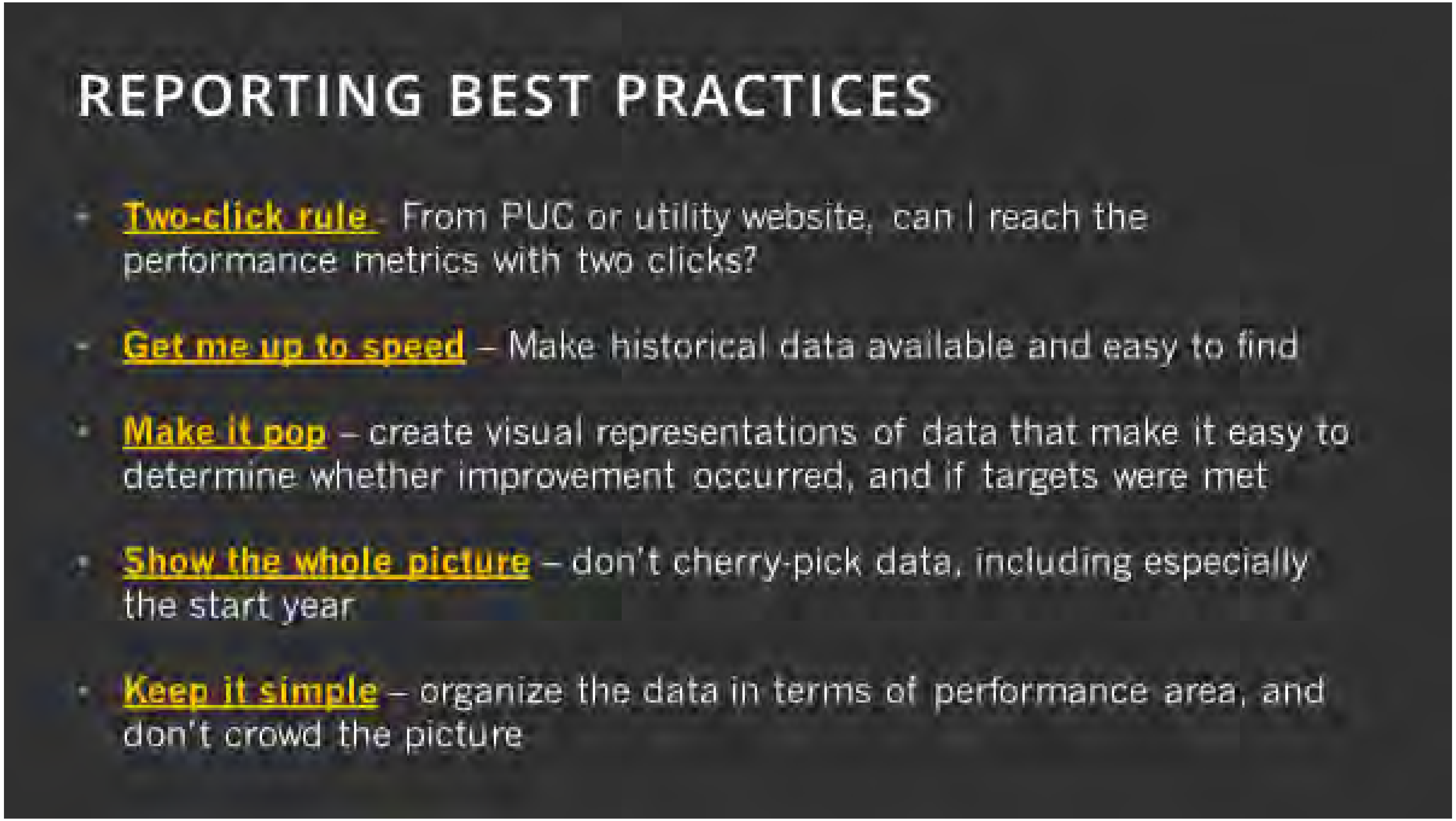
LEGEND: 🟢 = the target was met. 🔴 = the target was not met. | EXPORT: EXCEL

	Customer Focus						Operational Effectiveness										Public Policy Responsiveness			Financial Performance			
Distributor	New Residential/Small Business Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)	Billing Accuracy (Target: 98%)	First Contact Resolution	Customer Satisfaction Survey Results	Level of Public Awareness	Level of Compliance with Ontario Regulation 22/04 (Target: substantially compliant)	Number of General Public Incidents	Rate per 10, 100, 1000 km of line	Average Number of Times Power to Customer is Interrupted	Average Number of Hours Power to Customer is Interrupted	Distribution System Plan Implementation on Progress	Efficiency Assessment (1 = most efficient 5 = least efficient)	Total Cost ($) per Customer	Total Cost ($) per Km of Line	Net Cumulative Energy Savings (Percent of Target Achieved)	Renewable Generation Connection Impact Assessments Completed on Time	New Micro-Embedded Generation Facilities Connected on Time (Target: 90%)	Liquidity: Current Ratio	Leverage: Total Debt to Equity Ratio	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Achieved
Alectra Utilities Corporation	92.59% 🟢	98.75% 🟢	75.78% 🟢	100% 🟢	85.1%	93%	82%	C 🟢	20	0.95	1.26	1.07	114%	3	716	15212	100.17%	100%	78.26% 🔴	0.82	1.16	8.95%	7.21%
Algoma Power Inc.	97.1% 🟢	100% 🟢	81.61% 🟢	100% 🟢	99.96%	95%	83%	C 🟢	0	0	3.39	7.33	Completed	5	2235	12107	76.74%			0.69	1.36	9.30%	8.44%
Atikokan Hydro Inc.	100% 🟢		100% 🟢	99% 🟢	100%	100%	83%	C 🟢	0	0	0.19	0.42	On Target	3	1035	18329	71.92%			1.35	0.17	8.78%	7.62%
Bluewater Power Distribution	99.77% 🟢	100% 🟢	87.4% 🟢	100% 🟢	99.99	74.4	87%	C 🟢	0	0	1.87	1.88	At Budget	3	734	34871	94.52%	100%		1.13	0.69	8.98%	10.93%

Xcel Energy Dashboard Development Option

- Models could run similar to the HECO system with a simplified Microsoft Excel and Word input with uploads to website OR a more comprehensive linked option with automatic system queries and uploads.
- Estimated costs can vary significantly depending on desired complexity from a broad estimate of $125k to $1.5M to develop plus annual maintenance costs for data management of $200,000.
- Dependent on items such as:
  - Extensiveness of data query – build for automation or staff resources to pull and verify reports
  - How often reporting – monthly, quarterly, annually
  - Detail required on the webpage; charts, graphs, historical reports, comparative data
  - Other legal requirements necessary to be built into the webpage ex: Americans with Disabilities Act
- Are there other software options available to purchase parties are aware of?

Other Considerations?



Presentation to Performance Based Ratemaking Stakeholder Workgroup October 1, 2019: O'Boyle, Mike; Part of the Minnesota Performance Metrics Stakeholder Process; Reporting performance metrics

Next Steps

Meeting summary will be filed under docket 17-401, consistent with demand response financial incentive

Meeting summary will also be included in the PBR annual report filed on April 30, 2021 for Commission consideration in accordance with April 16, 2020 Order.


Xcel Energy®

Xcel Energy®

Performance Metrics Scorecard

April 30, 2021

Category	Metric	Previous Year Trend	2020	2019	2018	2017	2016
Affordability	Average Residential Bill	↑	$88.28	$83.74	$91.30	$84.75	$83.73
Reliability	SAIDI	↑	All Days: 134.19 Normalized: 98.92	All Days: 124.50 Normalized: 81.02	All Days: 125.00 Normalized: 96.07	All Days: 141.70 Normalized: 57.04	All Days: 214.39 Normalized: 90.45
Customer Service Quality	Customer Complaints	↓	.1341 per 1000 Customers	.2244 per 1000 Customers	.1417 per 1000 Customers	.0651 per 1000 Customers	.0571 per 1000 Customers
Environmental Performance	Total Carbon Emissions	↓	12,801,300 tons	16,229,466 tons	18,549,479 tons	18,891,471 tons	18,972,617 tons
Cost Effective Alignment of Generation and Load	Demand Response	↔	Total Capacity: 754.6 MW 155,967 MWh	Total Capacity: 737 MW 164,716 MWh	Total Capacity: 731 MW 155,645 MWh	Total Capacity: 658 MW 134,140 MWh	Total Capacity: 723 MW 134,550 MWh

MINNESOTA'S POWER PLANT COMMUNITIES: AN UNCERTAIN FUTURE

Developed by Center for Energy and Environment

February 2020

Authors:

Audrey Partridge

Brady Steigauf

Editor:

Dana Rider

Center for Energy and Environment

Acknowledgements

This report was informed by the insight and assistance of representatives from each of the communities included in the study, as well as numerous interviewees, community survey respondents, and experts who provided guidance on this work. We thank everyone who provided information and input throughout this project.

This report was prepared for and funded by the Just Transition Fund; the Coalition of Utility Cities; the Initiative Foundation, a regional foundation; the Southern Minnesota Initiative Foundation; the West Central Initiative Fund; Xcel Energy; and Center for Energy and Environment.

Table of Contents

Note from the Authors

It was an honor to have been a part of this research study and to hear the stories of individuals living in Minnesota's utility host communities and working in Minnesota's power plants. Visiting each community, we saw firsthand why residents, businesses, and elected officials love the places they call home. We heard community members' concerns and hopes regarding Minnesota's energy future and what they think it will mean for their communities, school districts, employment opportunities, and property values. We learned about businesses that would not exist if not for the neighboring power plant, and we realized how deeply community–utility relationships are woven into the social fabric of these communities.

We also heard the concerns community members have about living in proximity to a nuclear power plant and its stored fuel, as well as the painful history that some people have with neighboring power plants.

We are incredibly grateful to everyone who participated in this study, whether as a member of the Steering Committee, a funder, an advisor, an interviewee, or a survey respondent.

We enjoyed meeting members of these communities and hearing their stories. Yet it is a challenge to represent all those different voices and perspectives in a single report. Our task is to be neutral and mute on our personal and organizational perspectives and to focus on sharing the many stories we heard in an organized, honest, and productive manner. Each community has a unique perspective and voice, which we tried to convey authentically and accurately in our writing.

The findings and conclusions included in this report are based on what we heard in interviews, learned through our literature review, and know based on our own professional expertise. We hope that what is included in this report can be used by host communities to share their own stories, hear stories from other Minnesota host communities, and learn from the experience of communities across the nation who also face power plant closures.

EXECUTIVE SUMMARY

Many of Minnesota's large electric power plants will be eligible for retirement over the next 10 to 20 years. Given the changing economics of different sources of electricity as well as Minnesota's policy goals around reducing greenhouse gas emissions, power plant retirement dates are in flux. Xcel Energy proposed early retirement dates for some of its plants in its latest integrated resource plan, while also proposing to extend the life of one of its nuclear power plants. Other Minnesota electric utilities will file integrated resource plans, proposing power plant retirement dates in the coming years.

Large power plants not only provide electricity for the state, but are also the economic engines of the communities in which they are located. They are often the largest employer and largest single source of tax revenue for the communities that host them. Moreover, power plants and power plant workers play a significant role in shaping host communities. As large central power plants retire, the host cities and communities will transform as well.

To explore the challenges and opportunities associated with power plant retirements, the Center for Energy and Environment (CEE) led an assessment of the social and economic impacts of five power plants across six communities that host them. Table 1 shows each of the power plants and communities included in the study, along with their utility owner, fuel type, and estimated retirement date.

Table 1: Utility Host Communities and Power Plants

Community	County	Power Plants	Utility Owner	Fuel	Estimated Retirement
Becker, MN	Sherburne	Sherburne County Generating Station 1, 2, 3	Xcel Energy	Coal	2023*, 2026*, 2030 (unit respective)
Cohasset, MN	Itasca	Boswell Energy Center 3, 4	Minnesota Power	Coal	2035†, 2036† (unit respective)
Monticello, MN	Wright	Monticello Nuclear Generating Station	Xcel Energy	Nuclear	2040
Oak Park Heights, MN	Washington	Allen S. King Plant	Xcel Energy	Coal	2028
Red Wing, MN	Goodhue	Prairie Island Generating Station 1, 2	Xcel Energy	Nuclear	2033, 2034 (unit respective)
Prairie Island Indian Community					

*Indicates approved retirement date.
†Indicates date of full depreciation (or accounting lifetime) — there are currently no proposed retirement dates.

The study authors conducted interviews with host community members, local government officials, local businesses, leaders of local nonprofit organizations, and representatives of organized labor unions that represent power plant workers. Additionally, the study authors conducted a nonrandomized, online community survey to gather a broader range of perspectives from the community. The study authors used information gathered through interviews and community survey responses to tell the stories of these communities and workers facing an unclear role in Minnesota's energy future and economy. These stories articulate the concerns and hopes of community leaders, community members, and plant workers, as well as describe ongoing efforts to assist communities and workers through plant retirement transition.

The authors also performed supplemental interviews with state workforce experts and a literature review of case studies on communities across the country that are transitioning through power plant retirements. The interviews highlighted the worker and economic development support that currently exists in Minnesota, and the case studies offered potential lessons from other communities that have undergone power plant transitions. This report covers the findings from this work with the intent of providing communities, stakeholders, and key decision-makers the information needed to plan and prepare for a successful and just transition for communities and workers.

The findings and conclusions from this study include the following:

1. Power plants have played an important role in building vibrant and stable communities across Minnesota. Power plant closures will undoubtedly have a strong economic and financial impact on the communities that host them, and potentially, other Minnesota communities as well.
2. Minnesota's host communities are currently pursuing a variety of strategies to plan and prepare for power plant closures and the economic transition that they will require. None of those preparation strategies are expected to fully offset the economic impact of a plant closure, but they may help mitigate the negative effects.
3. Planning and preparing for a community transition related to a power plant closure requires a long time horizon.
4. Uncertainty or a lack of information around the timing of a power plant closure poses additional challenges for a community's planning and preparation.
5. Land use and redevelopment of power plant sites after a plant has closed is an important issue for Minnesota's host communities.
6. Minnesota plant workers, the unions that represent them, and the host communities have shared interests and concerns regarding power plant closures. Workers, labor unions, and host communities may benefit from close coordination and communication in plant closure transition planning and preparation efforts.
7. In today's economy, power plant jobs are uniquely high in quality. There are no clear options to replace power plant jobs with positions that are similar in terms of pay, benefits, stability, and location.
8. Not all of Minnesota's host communities receive benefits from the power plant they host.

HOW TO READ THIS REPORT

This report is structured as follows:

1. **Section 1** introduces the study's purpose and process and provides a brief overview of the Minnesota communities it includes.
2. **Section 2** provides background and context for each of the communities included in the report as well as a description of the communities' interviews and survey responses.
3. **Section 3** provides information on the role of organized labor in the power plants included in this study as well as a description of interviews with representatives from three labor unions who represent power plant workers.
4. **Section 4** provides the authors' findings and conclusions.
5. **Appendix A** provides a detailed description of the methodology used for this study.
6. **Appendix B** provides a description of key state financial policies that are pertinent to Minnesota's power plant communities.
7. **Appendix C** provides a description of existing workforce services and support offered through the Minnesota Department of Employment and Economic Development that may be helpful for workers and communities facing power plant closures.
8. **Appendix D** is a literature review of four case studies of power plant communities elsewhere in the country that are facing or have experienced a plant closure, as well as the findings and takeaways from those case studies. Appendix D also includes a bibliography of resources consulted for this study.

SECTION 1: INTRODUCTION AND BACKGROUND

Across the United States, evolving economics, aging electric generation infrastructure, and new energy technologies are driving significant changes in the way electricity is generated and consumed. State, local, and corporate goals to reduce greenhouse gas emissions are accelerating the pace of change.

This national trend is also true for Minnesota. In the next 22 years, more than half of the power plants responsible for the state's current electric generation are eligible for retirement. Minnesota's electricity supply, which traditionally began its journey at a central power plant, is shifting to a more complex and diverse mix of generation and demand-side resources. As our state's energy mix transforms and many of our large, central plants retire, the cities and communities that host utility power plants will transform as well.

In addition to powering our homes and businesses, these central power plants have powered the economies of the communities that host them. Most communities that are home to these large, central power plants — host communities — can attribute a large portion of their tax base, economic vitality, and local jobs to the plants. In some instances around the country, the loss of a power plant has resulted in negative social and economic consequences for host or nearby communities as well as plant workers. Many communities, utilities, labor unions, and local and state governments have employed a variety of strategies to assist communities and workers as they transition through a power plant closure.

For Minnesota's host communities looking ahead, power plant retirements carry both anxious uncertainty and reserved optimism. To explore the challenges and opportunities associated with power plant retirements, the Center for Energy and Environment (CEE) led an assessment of the social and economic impacts of five power plants across six communities that host them. Stories from host community members, local government officials, local business owners, leaders of local nonprofit organizations, representatives of organized labor unions, and workers in the power plants were collected through interviews and a nonrandomized community survey. These stories articulate the tensions and perspectives of host communities and workers as they face an unclear role in Minnesota's energy future.

The authors also performed supplemental interviews with state workforce experts and a literature review of case studies on communities across the country that are transitioning through power plant retirements. The interviews highlighted the worker and economic development support that currently exists in Minnesota, and the case studies offered potential lessons from other communities that have undergone power plant transitions. This report covers the findings from this work with the intent of providing communities, stakeholders, and key decision-makers the information needed to plan and prepare for a successful and just transition for communities and workers.

Host Communities

This study includes five different Minnesota electric power plants that face a likely retirement within the next 20 years as well as the six communities that host those plants.[1] The participating communities range in population from approximately 2,000 to 16,500 residents and are located throughout the state of Minnesota. Table 1 provides a list of each community included in the study and its associated power plant, along with the fuel type and estimated retirement date for each plant. Figure 1 provides a map depicting the location of each of these power plants and host communities.

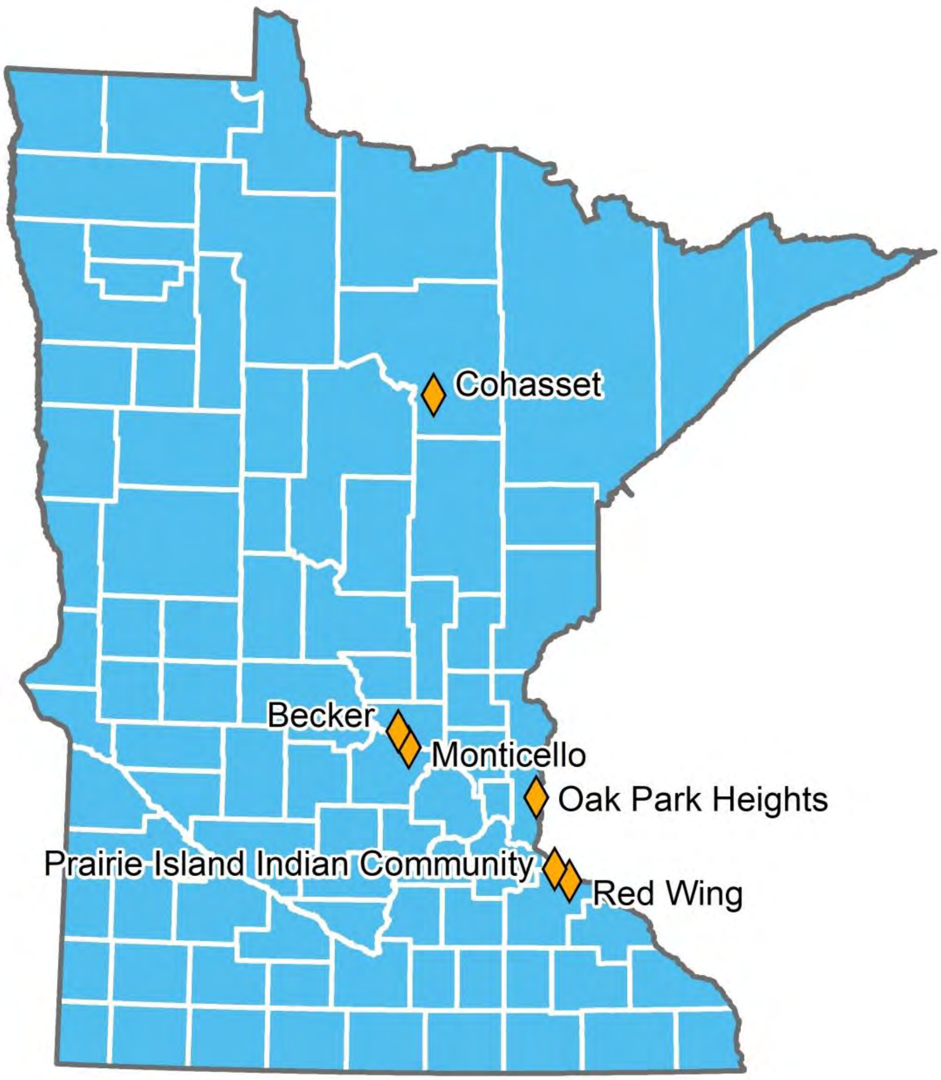
Table 1: Utility Host Communities and Power Plants

Community	County	Power Plants	Utility Owner	Fuel	Estimated Retirement
Becker, MN	Sherburne	Sherburne County Generating Station 1, 2, 3	Xcel Energy	Coal	2023*, 2026*, 2030 (unit respective)
Cohasset, MN	Itasca	Boswell Energy Center 3, 4	Minnesota Power	Coal	2035†, 2036† (unit respective)
Monticello, MN	Wright	Monticello Nuclear Generating Station	Xcel Energy	Nuclear	2040
Oak Park Heights, MN	Washington	Allen S. King Generating Station	Xcel Energy	Coal	2028
Red Wing, MN **Prairie Island Indian Community**	Goodhue	Prairie Island Nuclear Generating Station	Xcel Energy	Nuclear	2033, 2034 (unit respective)

*Indicates approved retirement date
†Indicates date of full depreciation (or accounting lifetime) — there are currently no proposed retirement dates.

[1] The Prairie Island Nuclear Generating Station is located on City of Red Wing land, but is directly adjacent to the Prairie Island Indian Community reservation. Both Red Wing and the Prairie Island Indian Community were included as host communities in this study.

Figure 1. Map of Minnesota Host Communities



Each community included in this study has unique economic opportunities and social structures, influenced by its size, geographic features, history, regional economy, and proximity to larger metropolitan hubs. For ease of reference, Section 2 offers a brief overview of each of the communities included in the study as well as the power plants they host, directly preceding discussion of the corresponding communities' interviews and survey responses.

SECTION 2: MINNESOTA'S POWER PLANT HOST COMMUNITIES

Becker

Background Information

Table 2: Sherburne County Generating Station (Sherco) Quick Facts

Power Plant Information	
Power plant fuel type	Coal
Projected Closure Date (unit respective)	2023, 2026, 2030*
Generation capacity	2,500 megawatts
Plant employees	301
Average annual plant employee income[2]	$88,556
City information	
City population	4,800
% of plant workers residing in city	20%
% of city's tax base from power plant	77%
County information	
Sherburne County population	94,600
% of plant workers residing in county	31%
% of county's tax base from power plant	14%
School district information	
% of school district's tax base from power plant	54%

*Indicates retirement dates not yet approved by the PUC

Becker is a central Minnesota city located in Sherburne County, about 45 miles from the Twin Cities. Becker has a population of approximately 4,800.[3] Becker is home to the Sherburne County Generating Station, a three-unit coal-fired power plant owned by Xcel Energy, with total capacity of 2,500 megawatts. The first two units at Sherburne County Generating Station, also called "Sherco," were originally commissioned in the mid-1970s, and the third unit was commissioned in 1987. The third unit at Sherco is co-owned by Xcel Energy and Southern Minnesota Municipal Power Agency.

Sherco employs approximately 300 plant employees, 20% of whom live within Becker and 30% of whom live within Sherburne County. Property taxes from Sherco make up approximately 77% of Becker's city tax base, 14% of Sherburne County's tax base, and 54% of the Becker School District's tax base.

In Xcel Energy's 2015 integrated resource plan, the Minnesota Public Utilities Commission approved retirement of two of the three units, in 2023 and 2026.[4] In 2017, the Minnesota legislature passed a law providing Xcel Energy statutory permission to build a combined cycle natural gas plant in Becker to replace the capacity lost with the unit retirements in 2023 and

[2] Average annual plant employee income was calculated using 2018 data provided by the utility.
[3] Estimated by the U.S. Census Bureau in 2017.
[4] "Sherco I & II Decommissioning." City of Becker. Accessed August 6, 2019.
https://www.ci.becker.mn.us/262/Sherco-I-II-Decommissioning

2026. The bill was signed into law by Minnesota Governor Mark Dayton.[5] In its 2019 resource plan, Xcel Energy proposes closing the remaining Sherco coal unit by 2030.

Findings from Interviews and Community Survey

The study authors conducted a community survey and multiple interviews with Becker residents, community leaders, and local government officials to gather information about how individuals and organizations are thinking about and planning for the eventual retirement of the Sherco Generating Station.

Nine Becker community members took the survey. In-person interviews with Becker's local government officials included Becker Mayor Tracy Bertram, City Administrator Greg Pruszinske, Sherburne County Commissioner Tim Dolan, Becker Township[6] Board Chair Brian Kolbinger, Becker City Council Member Mike Doering, and Becker Public School Board Vice Chair Connie Robinson. Interviews with Becker community members included one business representative, Chuck Legatt of Liberty Paper, and one local faith leader, Pastor Rob Olsen of Becker Baptist Church.

Community members and officials alike recognize the great importance of the Sherco plant to the local economy as well as the social fabric of the city and its neighboring towns. Becker Mayor Tracy Bertram summarized her apprehension regarding the plant's retirement, stating, "Our biggest concern is tax base and how it will affect jobs for our citizens here. And what it will mean philanthropically. Our charities will have to seek other avenues."

The mayor's concerns are shared by her constituents. Nearly all survey respondents were familiar with the approved and proposed retirement dates for the Sherco plant's units. All but one survey respondent reported feeling concerned about the future of the power plant and the impact a plant closure could have on the community. In both interviews and survey responses, participants emphasized the integral role the Sherco plant has played in shaping the town. "It has defined who we are as a community and allowed excellent schools, golf course, etc. that would not be here without taxing the power plant," stated one Becker business owner in a survey response.

Looking forward, survey participants and interviewees reported optimism that the city will be able to attract new businesses and expand its industrial park to absorb future losses in jobs and tax base due to the power plant retirement. Survey respondents and interviewees hope

[5] Dunbar, Elizabeth. February, 28, 2017. "Dayton signs bills allowing natural gas plant in Becker." MPR News. https://www.mprnews.org/story/2017/02/28/dayton-signs-bill-allowing-natural-gas-plant-in-becker

[6] The Becker Town Board and the City Council have partnered on a variety of projects and services. For many years, the City and Township have collaborated via a Joint Powers Fire Board. Funding for fire services is shared between the two governmental subdivisions. Since 2007, the Township and City have coordinated the jurisdictions' short- and long-term land use and economic development goals through a Joint Planning Agreement. The City of Becker, Becker Township, and five other neighboring governmental subdivisions are part of a Joint Powers Agreement established to drive regional economic development, including capacity building within the regional transportation networks.

that their town will grow, while maintaining its quiet charm, quality of life, great schools, and low taxes.

The following section describes community members' and officials' survey responses and interview discussions.

Host Community Story

The Plant that Built the Town

For the last several decades, the Sherco power plant has powered not only a large portion of Minnesota, but also the growth and development of Becker. Prior to the Sherco plant, Becker was a rural town with only a few hundred residents and very little commerce. After the Sherco plant was commissioned in the mid-1970s, the town's population grew from roughly 360 residents to nearly 4,800 today. Many interviewees stressed that the city itself developed around, and largely because of, the Sherco plant. One community member stated, "[Sherco] has defined who we are as a community."

Council Member Mike Doering explained the town's transformation, saying, "Initially, the general community benefitted [from the plant] as far as population goes. The large majority of them lived in the [Becker] Township because there really wasn't any place for them to live in the city. It stayed that way for several years, but once we built the golf course, the community center, and started to build up the parks and rec stuff, people wanted to live in Becker. That's when the city grew quickly." According to interviewees, as of the late 1990s and early 2000s, Becker was one of the fastest growing communities in Minnesota.

Utility Contributions to the Tax Base

As the community faces the likely closure of the Sherco plant, tax revenue from the plant is top of mind for leaders and members of the community. According to Pastor Rob Olsen of the Becker Baptist Church, many in his faith community are approaching the future with fear. "There are a lot of people who are concerned about the loss of tax flow. Becker has learned to live with that tax base from Xcel. Our city leaders are doing a great job of weaning us off of that dependence. It is a concern about what happens next — particularly to residential taxes."

Community survey responses reiterated that concern. Six of nine survey respondents expressed concern about their taxes increasing when the plant closes. Other survey respondents noted concerns about cuts to city services and amenities as a result of losing tax revenue from the plant. One survey respondent stated, "I have concerns over the economic impact this will have on the city. We have a very nice city with very exciting amenities, and I fear that will take a huge hit when the plant closes." Other fears noted in surveys included a wave of layoffs, the collapse of the school district, and residents leaving the town for other jobs.

> "At 76% [of the City's tax base], it's probably easier to point to stuff [Sherco] didn't pay for. It's a much shorter list."
>
> —Sherburne County Commissioner Tim Dolan

The Sherco plant is, by far, the City of Becker's largest tax contributor. In 2018, tax revenue from the Sherco plant made up 77% of the City's tax base, 14% of Sherburne County's tax base, and 54% of the Becker School District's tax base. Tax revenue from the power plant funds basic operations for the city, county, and schools as well as capital projects, capital purchases, and investments in public safety. Sherco taxes pay for the vast majority of the City's expenses, allowing it to maintain infrastructure and provide services for its residents and businesses while keeping taxes low.

Sherburne County Commissioner Tim Dolan explained how the county uses plant tax revenue, "At the county level, it goes to our general fund. However, we have made a concerted effort to earmark certain percentages of it to help the city and the township with the transition efforts. It's not a hard and fast number, but we have an understanding that we're committed to the transition effort here."

Those collaborative transition efforts are primarily focused on investments in infrastructure to attract and retain businesses within the city. The City of Becker, in partnership with Sherburne County, invested in preparing an industrial park and working to attract new businesses to the city. Currently, Becker and Sherburne County, along with Xcel Energy, are working with a large-scale data company in an effort to bring a data center to Becker as well.

Despite its ambitious economic development plans, the City has been conservative in issuing levies and spending for economic development activities. In the 1980s, Becker created a special tax district that included the Sherco plant to develop an economic development fund to pay for an industrial park. "We didn't do any special levy on the power plant other than the industrial park. That was specifically for the power plant. It was to get the industrial park going," said Becker City Council Member Doering.

With those funds, the City prepared a 70-acre industrial development site with "shovel-ready" land, complete with the necessary infrastructure investments, zoning, planning, and environmental studies for the site. "We're working to get stuff going. Infrastructure is key … without shovel-ready land, [businesses] won't even talk to you," said Council Member Doering. The industrial park also includes access to rail and proximity to the Mississippi River and Highway 10.

The site is already home to several businesses, and the city is working to attract additional businesses to fill the remaining land parcels. One large tenant for the industrial park is Northern Metals Recycling. Northern Metals is in the final construction phase of a 50-acre facility in Becker that will process everything from industrial metals to old cars. The facility is expected to employ 85 workers.[7]

The community's business recruitment efforts are thoughtful and targeted to specific types of businesses. Becker Township Board Chair Brian Kolbinger explained, "Aside from the tax dollars, [the large-scale data company] will provide opportunities for skilled resources in our

[7] Gray, Callan. July 9, 2019. "Northern Metals prepares to open facility in Becker." KSTP 5 Eyewitness News at 10. https://kstp.com/business/northern-metals-prepares-to-open-facility-in-becker-business-/5417660/

community that currently may not exist, opportunities that typically only exist in larger communities."

City Administrator Greg Pruszinske explained that the City is working to attract the types of jobs that match the skill sets of current Sherco plant workers in an effort to provide opportunities for them to transition to other positions within the city. "Some of the jobs at the plant are technology based," Pruszinske explained. "One of the things we're trying to do locally here is capture a large scale data center to use the knowledge base that we already have. That's part of the strategy. It's kind of dry and boring, but a lot of the things we're working on are things like zoning issues, setbacks from the wild and scenic river area — there's a plan to build a water treatment plant to treat surface water to cool a data center, and we're talking about water and sewer lines and streets … it's all rather mundane, but stuff you have to do to accommodate any sort of business."

Social Contributions of the Utility and Plant Workers

Xcel Energy provides a number of benefits to the community beyond its contributions to the tax base. Xcel Energy has partnered with the City of Becker in its efforts to attract new businesses and expand its economy by providing access to its in-house experts to augment county and city staff and resources. For example, a data company issued a request for proposals (RFP) to find a location for a new, large data center. Xcel Energy provided substantial assistance to Becker in developing a proposal to respond to the RFP. "It was a typical RFP process. Talk about access to expertise. Responding to that type of RFP, the City of Becker would have been hard pressed to do that without Xcel Energy," stated Sherburne County Commissioner Tim Dolan.

Sherburne County Commissioner Tim Dolan continued, "Aside from their tax dollars, [Xcel Energy] staff occasionally collaborate with resources in many areas that cities the size of Becker, or even counties the size of Sherburne County, can't necessarily afford to staff full-time. They are a large organization with a lot of resources and access to information and technology that we don't necessarily have. Xcel is a model corporate citizen in our community."

"Xcel is the reason [the large-scale data company] is talking to Becker," said Council Member Doering, "Their expertise and access to resources is huge. They're good corporate partners."

The utility–community partnership is also apparent through the utility's philanthropy and plant employees' philanthropy and volunteerism. Both survey participants and interviewees enthusiastically described Xcel Energy as an excellent community partner. "Xcel has been generous both financially, in terms of supporting events, as well as allowing employees to volunteer in the community," Pastor Rob Olsen stated. "That forges a relationship and a positive attitude between those that live and work here."

Interviewees described in detail Xcel Energy's charitable efforts in Becker, including:

- Supporting an internship program at the plant that allows two high school students to job-shadow at the plant to learn about opportunities to work there;
- Donating $70,000 annually to United Way, as well as sponsoring a golf tournament in Becker where proceeds go to the organization;

- Donating to the Becker School Robotics Club, as well as allowing plant engineers to spend company time advising students on designs;
- Donating to the Becker Joint Operating Fire Fund and Becker Police Department;
- Donating to the Becker Area Senior Center;
- Hosting an annual Mississippi River clean-up event for plant employees;
- Donating to the Becker Youth Association, a nonprofit that funds youth sports teams and a "backpack buddies" program that sends food home with kids that might otherwise go hungry after school;
- Supporting a "Day of Giving" for plant workers to volunteer with the charity of their choice on company time; and
- Donating to Meals on Wheels to deliver nutritious meals to seniors.

Going forward, interviewees and survey respondents fear that these longstanding community contributions will disappear if the power plant closes. Mayor Tracy Bertram noted her concerns about potentially losing the Sherco plant internship program, "Those children won't have the exposure to any of the jobs that come out of that [Sherco] facility …That opportunity would be gone."

A community survey participant expressed their concerns, stating, "Local charities would be affected by losing a large corporate citizen, as well as the loss of jobs that would affect individual giving."

Relationship with Liberty Paper

Liberty Paper, Inc., (Liberty Paper) is an important employer in Becker, with a unique relationship to the Sherco power plant. Liberty Paper is a manufacturing company that recycles corrugated boxes into paper. The company employs approximately 165 people, roughly half the number of employees at the Sherco plant. Located adjacent to Sherco, Liberty Paper purchases steam from the Sherco plant to use for its operations. "We're a business partner as well as neighbors," said a business representative from Liberty Paper. "Our relationship has evolved over the years: As renewables come on board, the way [Xcel Energy dispatches steam] power out of the [Sherco] units has changed, and that has impacted us. But we have a strong relationship … Right now we rely on them for steam, electricity, and gas. They really create our competitive advantage within our industry because it's competitive out there."

When the Sherco plant retires, Liberty Paper will be faced with a difficult choice to either build its own supply of steam or relocate. That situation might be avoided if the Sherco plant is replaced with the planned combined cycle natural gas plant. "With the potential to have a combined cycle plant here, that also benefits our operations here and gives us flexibility on our thermal energy needs." The Liberty Paper relationship highlights the interdependence of Sherco plant and other important Becker businesses.

Transition Efforts and Vision

Becker residents and community leaders hope to see Becker and the surrounding community grow, while also maintaining its small town charm and many other amenities and characteristics that residents value. Community survey respondents as well as local officials noted Becker's great schools, parks, golf course, and public safety institutions as assets they hope to hold on to long after a Sherco plant closure.

One community survey respondent described their vision of Becker 10 years from today, stating, "[I hope the city] double[s] in size, but still has a 'small town' feel, replaces tax income dependency from the current power plant with other sources, still safe and secure with similar or improved amenities, still strong schools at elementary and high school level."

Continued Role as a Power Provider

Given state legislation permitting Xcel Energy to replace two of Sherco's generating units with a combined cycle natural gas plant, Becker may continue its role as a power provider for the state. This would provide some tax revenue to the county and city as well as jobs to the community, and may also allow Liberty Paper to remain in its current location and to continue purchasing steam from Xcel Energy. The prospect of this plant has eased some community members' fears. According to Pastor Olsen, "It has been a relief knowing that gas would be the replacement as a utility investment."

However, the number of jobs at a new natural gas plant would be significantly lower than the number of jobs at the current Sherco coal facility. It is expected that the combined cycle natural gas plant will require about 15 employees, compared to about 300 employees at the current Sherco coal facility. The city hopes that many of the jobs that would be lost due to a Sherco coal plant retirement would be handled through attrition and reassignment rather than layoffs. "One thing Xcel has done pretty well over the years is control their manpower through attrition. There are some guys in their young 30s that work at the plant right now. If that plant shuts down, are they out of a job? Not necessarily. They might be transferred over to the gas plant," explained Council Member Doering.

Diversifying the Local Economy

To ensure Becker's community transition is a success, Becker's elected officials, City staff, and development authority are working to diversify the city's business community, attract transitional support, and prepare its residents for a different, but still bright, future. As discussed above, Becker has been working with Northern Metals Recycling and the large-scale data company to secure them as anchor tenants in the town's industrial park. Community leaders and members hope that by bringing those large businesses to Becker, more companies will follow. One survey respondent wrote, "[The large-scale data center] coming would be huge. Not because of the 50 jobs expected, but because of the other companies that want to be close to [its] server farm (Intel, Amazon, Microsoft, etc.). Liberty Paper is growing nicely as well."

> "This [transition] is allowing everyone to think about what Becker is — and what it could be.… It would be a lot easier to let the plant leave and everyone with it, but that's not what we're fighting for."
>
> —Pastor Rob Olsen
> of Becker Baptist Church

Pastor Olsen explained, “The whole idea of this snowball effect: You start to get some building — be that the gas plant here or for [the data center] or anything else in the industrial park — that gets other businesses thinking ‘that must be a growing community; we want to be part of that. Maybe we should look at it — they’ve got shovel-ready lots.’”

Olsen continued, “Becker is one or two projects away from being one of the most diverse small town economies. This [transition] is allowing everyone to think about what Becker is — and what it could be.… It would be a lot easier to let the plant leave and everyone with it, but that’s not what we’re fighting for.”

Advocating for Their Transition

Though Becker is a small town with approximately 4,800 residents, it is using its strong voice to advocate for a successful transition for itself and other cities in a similar position. Becker Mayor Tracy Bertram stated, “We tell our story to anybody who will sit and listen. At the legislature, we connect with them on various levels and we tell them our story and how their decisions are impacting us. We ask them if they’ve seen other communities like us and ask what stories they can share to make us successful during this transition time.”

> “We tell our story to anybody who will sit and listen.… We ask them if they’ve seen other communities like us and ask what stories they can share to make us successful during this transition time.”
>
> —Becker Mayor Tracy Bertram

Becker also advocates for itself at the Minnesota Public Utilities Commission on issues related to the Sherco Generating Station and other host community issues. City Administrator Greg Pruszinske explained, “We’ve also been engaged in the decision-making process. Certainly through the Coalition of Utility Cities, but we have also been at key meetings that the Public Utilities Commission has been having when it comes to the decision of decommissioning [units] 1 and 2. We made sure that we were at the table, in the meetings, that the PUC Commissioners know who we are by name and same thing goes with Department of Commerce and environmental groups.… It’s very important to be known, but we have to have a voice.… We want something out of this and we should get something out of this as a host community. We’ve had 2,400 megawatts going to the grid — including to the Twin Cities — for almost 50 years. The thing goes away, we should partner with the State of Minnesota and other stakeholders to have a logical transition pathway forward.”

Cohasset

Background Information

Table 3: Boswell Energy Center Quick Facts

Power Plant Information	
Power plant fuel type	Coal
Projected closure date (unit respective)	2035*, 2036*
Generation capacity	922.5 megawatts[8]
Employees	170
City Information	
City population	2,700
% of plant workers residing in city	10%
% of city's tax base from power plant	69%
County Information	
Itasca County population	45,200
% of plant workers residing in county	90%
% of county's tax base from power plant	13%
School District Information	
% of school district's tax base from power plant	19%

*Indicates date of full depreciation (or accounting lifetime) — there are currently no proposed retirement dates.

Cohasset is located in Itasca County in northern Minnesota along the Mississippi River, on the western edge of the Mesabi Iron Rage. Cohasset is about 185 miles from the Twin Cities and 90 miles from Duluth.[9] Cohasset has a growing population of approximately 2,700 residents,[10] and it is adjacent to Grand Rapids, a town with about 11,000 residents.[11] Cohasset is home to Minnesota Power's Boswell Energy Center, a four-unit coal-fired power plant with a combined capacity of 1,070 megawatts.[12] The first and smallest two units of the Boswell Energy Center were commissioned in 1958 and 1960, respectively, and were retired in 2018. The third unit came online in 1973 and the fourth unit in 1980 — both continue to operate today.

The Boswell Energy Center employs approximately 170 workers, 10% of whom reside in the city of Cohasset and 90% within Itasca County. Property taxes from the Boswell Energy Center make up almost 70% of Cohasset's annual city tax base, 13% of Itasca County's tax base, and 19% of the Grand Rapids School District tax base.

The third and fourth units of the Boswell Energy Center will be fully depreciated in 2035 and 2036, respectively. Minnesota Power has not yet proposed a retirement date for either unit.

Findings from Interviews and Community Survey

The study authors conducted a community survey and in-person interviews with Cohasset residents, community leaders, and local government officials to gather information about how

[8] "Boswell Energy Center." Global Energy Monitor Wiki. Accessed July 2, 2019. https://www.gem.wiki/Boswell_Energy_Center
[9] Duluth is Minnesota's third largest city based on estimates of the U.S. Census Bureau in 2017.
[10] Estimated by the U.S. Census Bureau in 2017.
[11] Estimated by the U.S. Census Bureau in 2017.
[12] "Generation." Minnesota Power. Accessed July 2, 2019. https://www.mnpower.com/Company/Generation

individuals and organizations are thinking about and planning for a possible retirement of the Boswell Energy Center.

Six Cohasset community members participated in the survey. In-person interviews with local officials included Cohasset Mayor Greg Hagy; City Director of Operations and Finance Manager Max Peters; Public Works Supervisor, member of the Cohasset Fire Department, and treasurer of the Cohasset Firefighters Relief Association Duane Kilde; Recreation Coordinator Dave O'Fallon; and Zoning Officer Greg Tuttle. The interview also included one community member, and another community member provided written responses to interview questions at a later date.

Despite there being no proposed retirement dates for the remaining Boswell units, community survey participants and interviewees expressed concern and anxiety regarding a possible loss of the Boswell Energy Center. Most of the concern was focused on the loss of tax revenue for the City, County, and schools, as well as the loss of employment opportunities for community members. Anxiety has been heightened as rumors and discussion of possible early plant closure dates circulate.

The City of Cohasset is actively investing in a number of special projects in an effort to bring new tax revenue and more economic activity to the community. The following describes community members' and community leaders' survey responses and interview discussions.

Host Community Story

The Role of the Boswell Energy Center in Cohasset

Cohasset is the smallest city included in this study. Located on the western edge of Minnesota's Iron Range, it is also the most geographically isolated from larger metropolitan areas that may offer additional employment opportunities. Moreover, other industries like paper mills and mining that have typically provided employment opportunities in Cohasset, like paper mills and mining companies, are in decline and downsizing their workforces. Therefore, the Boswell Energy Center plays an oversized role for Cohasset's economy and identity. Highlighting Boswell's critical role in Cohasset, Cohasset Mayor Greg Hagy stated, "This is almost a death sentence if we lose the power plant."

The Boswell Energy Center is a large and important employer in Cohasset, with approximately 170 full-time plant workers year-round and hundreds more during maintenance outages. Additionally, there are many workers employed indirectly through suppliers, vendors, and contractors. Interviewees noted Boswell's important role in creating jobs (1) on the rail line used to transport the coal; (2) in construction, to maintain the roads and infrastructure that serve the plant; (3) for numerous contractors that supply parts and labor to the plant; (4) for restaurants, hotels, and other hospitality businesses that serve plant workers; and (5) for the 27 firefighters that are paid to be on call to respond to potential emergencies at the plant and in the community.

Broader trends in the regional economy were a significant theme throughout interviews and survey responses. The declining industry and job loss have been themes for the region. Many community members and local officials mentioned the recent layoffs at Blandin Paper, once the community's largest employer. In 2017, Blandin Paper announced the layoff of 150 employees.[13] Minnesota Power's Boswell Units 1 and 2 were shut down just a few months later, laying off more than 150 plant workers as well. "We've lost a lot of jobs in the last five years," said one community member interviewee.

Another community member stated, "[Boswell] is significant to the community and likely has been in the top three [in terms of employment] over the years. It used to employ more than 250 people locally but now [it has] about 185. It is scary to think about what the community of Grand Rapids would look like in the second poorest county in the state when it loses Boswell and Blandin with no other major prospects."

On interviewee stated, "A lot of these cities [on the Iron Range] are struggling. There's no revenue. For a lot of towns on the Range, there's nothing left. My guess is if [Minnesota Power] left, we would lose people. Taxes would go up, services would go down, we'd lose jobs and we'd lose people."

Cohasset's community survey respondents indicated that there are few to no alternative employment opportunities for plant workers if it were to close. All six survey respondents discussed the job opportunities that the Boswell plant provides to the community. No survey respondents reported optimism regarding an upcoming plant closure. In response to a question about other job opportunities in the community, one respondent wrote, "None!! The mines are closed. The paper mill is laying off. There are no jobs."

> "This is almost a death sentence if we lose the power plant."
>
> —Cohasset Mayor Greg Hagy

Another survey respondent stated, "[Boswell] is a large employer and tax payer, and if it were to close unexpectedly it would have a calamitous effect on the economy."

Utility Contributions to Tax Base

Tax revenue from the Boswell plant makes up a significant portion of the area's various municipal tax bases. As noted above, 2018 revenue from the Boswell plant accounted for approximately 69% of Cohasset's city tax base, 19% of the Grand Rapids School District tax base, and 13% of Itasca County's tax base.

Compared to adjacent cities, Cohasset residents and business enjoy some unique amenities while paying significantly less in property taxes. Tax revenue received from the Boswell power plant funds the majority of the city's operations, services, amenities, and investments, keeping resident and business taxes low. City Director of Operations and Finance Manager, Max Peters explained, "The biggest thing that it allows us is to have a lower than average percentage of tax capacity levy. So that the amount of dollars that we levy to people as a percentage of our tax

[13] October 24, 2017. "UPM Blandin to shutter one Grand Rapids paper machine, cut 150 jobs." Business North. http://www.businessnorth.com/daily_briefing/upm-blandin-to-shutter-one-grand-rapids-paper-machine-cut/article_0fac28e6-b8ca-11e7-8e91-bf2ad7428a24.html

capacity is lower because of Minnesota Power, which allows us to do [special projects] like the industrial park, community center, daycare facility, mountain bike trails. You look at Grand Rapids, it taxes at 84% of tax capacity. We tax at 26% of tax capacity. If we lost Minnesota Power tomorrow, we'd be taxing at 84%, and that's just the local tax implications. If you talk about taking [Minnesota Power's tax revenue] away from the County and the school district, the impacts of that are not small. It allows us to do more projects and keep our taxes low."

Cohasset's strategy of maintaining such low taxes, however, is not without criticism. One interviewee stated, "There is an argument that if we were really smart, we would tax at the highest we could to get [the revenue] while [Minnesota Power is] here. If we are taxing at 26% of our tax capacity, [we could raise it] if we wanted to collect more money from Minnesota Power.… The alternative is that we'll have to raise taxes in the future, and then Minnesota Power won't be in the picture."

"Right, well you're not an elected official. People are really sensitive about taxes," countered Mayor Hagy. Interviewees acknowledged that if the Boswell plant retired, taxes in the city would have to increase either way, and that would likely cause frustration among residents and businesses. "No one wants to pay more in taxes, but no one wants to get rid of the amazing services they're getting either," Public Works Supervisor and Cohasset Firefighter Duane Kilde stated.

While the tax levy remains low in Cohasset, the City currently takes in a healthy amount of tax revenue, which has allowed it to keep an eye toward the future and invest in special projects, discussed in detail below. These projects are intended to attract economic activity and businesses, as well as provide necessary services for the workforce and general public. "We've been trying to do what we can in case the inevitable does come. We're doing what we can to make revenue builders for our city," said Mayor Hagy.

Cohasset is investing in its unique natural assets by building a 500-acre recreational area on two of the region's most unique lakes, which will feature 30 miles of world-class single-track mountain bike, cross country ski, and hiking trails.[14] This area is called Tioga Recreational Area and is modeled after the Cuyuna trail system in Crosby, Minnesota. According to interviewees, the City of Crosby invested in the Cuyuna trail system a number of years ago, and it resulted in about $5 million of additional economic activity in Crosby per year.

Additionally, Cohasset is investing in its downtown area. The City purchased a 30-acre parcel of land in its downtown core along the Mississippi River and plans to prepare the site, construct a roadway, add utilities, develop park space, and build a 50-slip marina on the river. The City will then work to sell smaller parcels of land to private developers to construct multiuse buildings, including dining, retail, hotels, and condominiums.

Cohasset is also investing in an industrial park, business recruitment, and supportive services and amenities for the workforce to come. City Director of Operations and Finance Manager, Max Peters stated, "We invested $5 million into 300- and 400-acre industrial parks, we're

[14] Tioga Recreation. Accessed July 2, 2019. https://tiogarecreation.com/

investing in a community center and a daycare center to be secondary service providers for [residents] when we fill that area, and [we're] trying to grow tax base as much as we can to offset what we're eventually going to lose."

Mayor Hagy explained the strategy, "If someone comes into the community and does really well and both parents have jobs but can't find day care — they'll leave. You have to have daycare."

In addition to the special economic development projects, the City of Cohasset uses its current tax base from the Boswell plant to provide services unique for a community of its size. Cohasset, compared to other similar-sized cities, has a large, well-trained, and well-funded fire department. "The [tax] revenue goes to all of our training. As far as our budget goes, when we needed a firetruck, Minnesota Power basically paid half of it because our tax base from them was over 50%," Public Works Supervisor and Firefighter Duane Kilde explained. "If they have any emergencies, we are trained as first responders to get there. It's been a big asset to us as a fire department and [is] why we have 27 members."

> "A lot of these cities [on the Iron Range] are struggling. There's no revenue. For a lot of towns on the Range, there's nothing left. My guess is if [Minnesota Power] left, we would lose people. Taxes would go up, services would go down, we'd lose jobs and we'd lose people."
>
> —Interviewee,
> City of Cohasset

Additionally, Cohasset is remodeling and enlarging its local elementary school. That school was nearly closed by the district — students would have moved to other nearby schools outside of Cohasset. The proposal was voted down, and the City of Cohasset worked with the district to keep the school open. "The last referendum, they were going to close the school. People didn't want to lose that school. So we did our part to keep it here," said Mayor Hagy.

"The City paid $985,000 to expand the gym and then on top of that did a $3.6 million project to co-locate daycare and the community center to that school," said Peters.

The City of Cohasset is not the only beneficiary of the tax revenue provided by the Boswell plant. Communities across the region receive indirect financial benefits as well. "Some of the defining aspects of our property tax situation is that we don't collect [Local Government Aid from the State] because we're a utility city. And because we're a part of the Taconite Assistance Area, the Fiscal Disparities Program in place, the businesses in our community contribute a million dollars a year to that fund and we receive zero dollars from it. So that's tax base that's taken away from Cohasset," explained Peters.

"Cohasset is the net contributor to fiscal disparities in the northern fiscal disparities area," said Mayor Hagy. "If we lose [Boswell], we could become the largest net receiver of fiscal disparities funds. So that could really change things across the arrowhead." Analysis provided by the Coalition of Utility Cities estimates that the closure of the Boswell plant would reduce revenue in the Iron Range fiscal disparities pool by about 14%. This could have significant impact on other communities in the region that rely on that funding pool.

The tax base that Cohasset has come to rely on may already be changing. After the closure of Boswell Units 1 and 2 in 2018, the property value at the site went down, and so did its property taxes. Since that devaluation is so recent, Cohasset has yet to fully feel its effects. A future retirement of one or both of the remaining Boswell units would further decrease the plant's contributions in tax revenue.

Social Contributions of the Utility and Plant Workers

According to interviewees, Minnesota Power and its employees contribute to the Cohasset community in a number of ways beyond their contributions to the tax base.

According to one community member, Minnesota Power provides significant philanthropic support to the community. He explained that Minnesota Power has a regional foundation with a $20,000 annual budget to provide donations to the local community. The regional foundation's charitable giving is directed by a committee made up of Boswell plant employees. Additionally, Minnesota Power's foundation provides grants to projects within its broader service territory in northeast Minnesota. He also stressed the important role of plant employees who volunteer their time and contribute financially to local organizations. "[Boswell plant] employees are engaged through [the] Powerful Partners Program in which they can donate $500 to an organization when four employees donate four hours of time," the community member said. Boswell employees also serve on the boards for Second Harvest Food Bank, United Way, and the local Chamber of Commerce.

Another interviewee noted that the Minnesota Power pays to light the city's extensive bike trails and the ski grounds nearby the plant.

Community Perception of the Utility and Plant

Community perception of Minnesota Power and the Boswell plant have become increasingly positive over the years. "Twenty or thirty years ago there wasn't the same conversation as today. The sentiment now is as strong as it's ever been for [Minnesota Power] as a great community asset and partner," City Director of Operations and Finance Manager Max Peters said. "They communicate well with the city. I feel lucky to work with Minnesota Power because they seem like a receptive, willing partner rather than a rigid and adversarial."

Coal ash pollution from the Boswell Energy Center was once a major concern for the community and negatively affected the community's perception of Minnesota Power and the Boswell plant. "I've been living here for 33 years, and we used to have little bits of foam floating around," Public Works Supervisor Duane Kilde described. "When they put Unit 4 in, your cars would have little dots on it from the ash. But they've worked so hard to eliminate that. The dust used to come over our houses and blacken our decks. All that stuff has gone away. They've done a tremendous job of getting rid of that. Twenty years ago it was just like the mines with the iron ore — there was a negative perception. Now, people feel like we need them."

Peters noted that the community would be shocked to see historic pollution data from the plant compared to today. "They used to put a couple hundred pounds of mercury in the air each year. I don't think they've received the credit they deserve from the public for making those [improvement] investments and being proactive about it," Peters stated.

"They just put in new scrubbers on the stack.… It's kind of shocking that [the plant] would go away with all that they've done," added Kilde.

Transition Efforts and Vision

As discussed above, Cohasset is using its current healthy tax base to invest in an array of economic development efforts as well as supportive services and amenities for the community's workforce. Additionally, the City streamlined processes for obtaining building permits and changing zoning codes, and also reduced building fees to attract and encourage additional investment by businesses and residents. Nonetheless, City officials do not expect that all those efforts combined would fully replace the tax revenue currently provided by the Boswell plant.

City Director of Operations and Finance Manager Max Peters said, "The challenge is that we could fill our industrial park today and it wouldn't even be half of what Minnesota Power pays in tax capacity. That's what's so daunting.… Boswell is so big and so important."

An Uncertain Timeline

Though there is not yet an approved or proposed date to retire the Boswell plant, there is increasing conversation about a possible early retirement. This conversation is happening as Minnesota electric utilities are closing coal-fired power plants across the state for economic and environmental reasons. "As I understand it, the accounting perspective is that 2034 is the actual life span that the plant could be operating if there wasn't such a negative perspective on burning coal," said Peters.

The timing of a potential plant retirement looms large over City officials, who until recently expected Boswell to operate for decades to come. Peters explained, "For the last eight years I've been here, it's been heating up every year of 'When are we going to get rid of coal? When does Boswell go down?' If we were looking at our calendars, it was 2050 or 2065 — somewhere way out into the future where you've got a longer runway to plan and adjust for it … We've been trying to build tax base to offset what we will eventually lose. The challenge, recently, is that that timeframe is ramping up. What could have been 2050 or 2060 is now 2034 or 2028 or something even sooner than that. Even a year ago, if you'd asked me how important is it, it's something we're worried about but not a priority. But today — you know if this plant were to close down in 2028, we would have some very difficult conversations [to start]. It doesn't give us nearly the runway and time to plan for it."

An accelerated timeline for retirement would strain the City's long-term economic development plans and efforts, which may take decades to carry out. Peters stated, "We're exploring every opportunity that we can within reason, but that industrial park is a 20- to 30-year investment. That won't be full for 15, 20, or 30 years. The timeline *was* 2050 or 2065, but now you're talking 2028 and I can't fill that thing in eight years. Economic development is slow and unreliable."

For public input on its comprehensive plan, the City of Cohasset is planning to engage residents in its efforts to plan for the possible retirement of the Boswell Energy Center. As part of this, the City will send out a survey reminding residents that the Boswell plant covers nearly 70% of the City's overall tax capacity and asking what residents are willing to fund or wish to cut from city services and operations when the plant eventually retires. This question will feed into several others that will be asked to inform the comprehensive plan.

A Continued Role as a Power Provider

According to interviewees, Cohasset would welcome a continued role in Minnesota's energy future. City staff expressed hopes that the plant could be converted to natural gas or other cleaner fuels. According to Peters, "If we were sitting here and saying they [Minnesota Power] are going from 33% coal to 0% coal and it didn't impact the jobs or the tax base or the things that affect this community — then frankly we'd probably support it. If we had a choice of not burning [coal], and [it] was environmentally drastically better and didn't economically hurt us, that's what we're looking for." Peters continued, "For us, it's about losing jobs and the secondary benefits. If you could keep benefits all the same with a different technology, then we wouldn't be so fearful. What we're talking about here is plant closure. Shuttering a plant … If our benefits stayed the same, do we care if they're burning coal or natural gas or if it was wind, solar, hydro? If I had a choice, I'd prefer that it's all clean."

> "I understand the issues of global warming and the issues of using coal, but the effects that [plant closure] has on this community and northern Minnesota are not insignificant."
>
> —Max Peters,
> Cohasset Director of Operations and Finance Manager

Interviewees went on to state that they are looking for a "unicorn" — a way for the city to continue to generate power and receive substantial economic benefits from it without causing environmental harm.

"I understand the issues of global warming and the issues of using coal, but the effects that [plant closure] has on this community and northern Minnesota are not insignificant," said Peters.

Further, the effects of plant closures may have broader, statewide impacts. Mayor Hagy stated, "Across the state, you've got communities like Oak Park Heights and others in this position. This will affect the state." In the event of a plant closure, City staff hopes that Local Government Aid and Fiscal Disparity Program dollars from the Iron Range Resources and Rehabilitation Board will ease their transition.

Monticello

Background Information

Table 4: Monticello Nuclear Generating Station Quick Facts

Power Plant Information	
Power plant fuel type	Nuclear
Projected closure date	2040*
Generation capacity	671 megawatts
Plant employees	460
Average annual plant employee income[15]	$108,991
City Information	
City population	13,600
% of plant workers residing in city	16%
% of city's tax base from power plant	50%
County Information	
Wright County population	134,286
% of plant workers residing in county	32%
% of county's tax base from power plant	9%
School District Information	
% of school district's tax base from power plant	46%

*Indicates a date not yet approved by the PUC, as it would require a nuclear relicense approval

[15] Average annual plant employee income was calculated using 2018 data provided by the utility.

Monticello is a central Minnesota city located in Wright County, along the Mississippi River — about 40 miles from the Twin Cities. Monticello has a population of approximately 13,600 residents.[16] The city is home to Xcel Energy's Monticello Nuclear Generating Station, which is a boiling water reactor nuclear power plant with 671 megawatts of capacity. The Monticello Nuclear Generating Station began operations in 1971. In 2006, the Nuclear Regulatory Commission renewed the plant's license through 2030.[17]

Xcel Energy built a dry cask storage facility in Monticello in 2008. It is licensed by the Nuclear Regulatory Commission and is allowed to store fuel through the plant's current operation license.[18] Xcel Energy has stated that it is working with federal authorities to encourage the development of a permanent, off-site storage facility for spent nuclear fuel. [19]

The Monticello Nuclear Generating Station employs 460 plant workers, 16% of whom reside within Monticello and 32% within Wright County. Utility property taxes from the plant account for approximately 50% of Monticello's city tax base, 9% of the county's tax base, and 46% of the Monticello School District's tax base.

In its 2019 integrated resource plan, Xcel Energy proposed extending the federal license and operating life of the Monticello Nuclear Generating Station through 2040. The extension proposed in the plan must be approved by the Minnesota Public Utilities Commission; the plant must be relicensed by the Nuclear Regulatory Commission; and the company must receive a Certificate of Need for the plant, also from the Minnesota Public Utilities Commission.

Steps	Process	Expected Timing	Time Required
Step 1	Xcel Energy proposes to the Minnesota Public Utilities Commission to extend the life of a nuclear power plant as part of its preferred plan in its integrated resource plan. The proposal is approved, denied, or modified.	Initial filing on July 1, 2019; Supplemental filing on April 1, 2020	10–24 months
Step 2	Xcel Energy applies to the Nuclear Regulatory Commission to extend the license of a nuclear power plant. The application is approved or denied.	Mid-2023–Early 2025	5–6 years
Step 3	Xcel Energy files for a Certificate of Need with the Minnesota Public Utilities Commission to extend the life of a nuclear power plant. The request is approved or denied.	Mid-2020s	3–4 years

[16] Estimated by the U.S. Census Bureau in 2017.
[17] "Monticello Nuclear Generating Station." Xcel Energy. Accessed June 25, 2019. https://www.xcelenergy.com/energy_portfolio/electricity/nuclear/monticello
[18] "Nuclear Energy." Xcel Energy. Accessed June 25, 2019. https://www.xcelenergy.com/energy_portfolio/electricity/nuclear
[19] "Nuclear Energy." Xcel Energy. Accessed June 25, 2019. https://www.xcelenergy.com/energy_portfolio/electricity/nuclear

Findings from Interviews and Community Survey

The study authors conducted a community survey and multiple interviews with Monticello residents, community leaders, and local government officials to gather information about how individuals and organizations are thinking about and planning for an eventual retirement of the Monticello Nuclear Generating Station (Monticello nuclear plant).

Twelve Monticello community members participated in the community survey. In-person interviews with Monticello City staff included City Administrator Jeff O'Neill, City Finance Director Wayne Oberg, Communications Coordinator Rachel Leonard, and Community Development Director Angela Schumann. Wright County Commissioner Darek Vetsch, Monticello School District Superintendent Eric Olson, and a representative from the local Chamber of Commerce were also interviewed.

Overall, interviewees and survey participants expressed a mix of optimism and concern regarding the future of the Monticello nuclear plant and the surrounding community. Community members and local officials expressed a sense of relief that Xcel Energy requested to keep the plant open for another decade, but also anxiety that when the plant eventually closes, the city will lose tax revenue and a strong community partner.

> "Monticello functions as a 'standalone city' with a great school district … a healthy, comfortable way of life. Everything you need is here."
>
> —Monticello Chamber of Commerce Representative

The most common concern expressed by community survey participants was that closure of the power plant would create a social loss in the community. One survey response read, "The power plant in our community has been a big supporter to our Chamber of Commerce events, Rotary projects, and many other local festivals. Many of its employees are also our neighbors and friends; it is truly a sense of building a great community together."

Another survey respondent stated, "[The Monticello nuclear plant] has been a great partner to our community, and it plays a significant role in contributing the success of our community economic growth."

Survey respondents and interviewees also cited the community's great parks and recreational amenities, a strong volunteer base, and low property taxes as benefits they attribute to the Monticello nuclear plant. The following describes community members' survey responses and interview discussions.

Host Community Story

Utility Contributions to the Tax Base

The Monticello Nuclear Generating Station contributes a substantial amount of tax revenues to the City of Monticello, Wright County, and the Monticello School District. As noted above, property taxes from the Monticello nuclear plant make up roughly 50% of the city's tax base, 9% of Wright County's tax base, and 46% of the Monticello School District's tax base. Tax revenue from the plant goes toward general operating expenses and debt service.

The plant's tax revenue allows the City to keep taxes low for its residents and businesses, while maintaining a health city budget for public services. Monticello has the lowest residential tax rate of any city in Wright County, but also the highest tax base.

This healthy tax base, in part, allows the City to provide services uncommon for a city of its size at relatively low costs for its residents. For example, Monticello has an excellent community center with a water park, fitness center, senior center, and indoor playground area; excellently maintained parks and trails; and modest garbage and storm water utility charges. "The services that we provide make it a nice place to live," stated City Administrator Jeff O'Neill. However, O'Neill stressed that the City has not been excessive in the services it provides to its citizens. Moreover, the City is increasingly transitioning to fund services through user fees, a more typical funding approach for a city of its size. O'Neill stated, "The City of Monticello has not fully exploited the capacity to fund services and amenities. We do have nice things: We have a community center; we did have garbage collection at no cost, which was centralized. That now is shifting becoming more of a user-based fee. And we've shifted our storm water utility to be funded less by Xcel and more by user fees."

The City's transition toward funding more of its services at least partially through user fees is a proactive step in its long-term effort to reduce its dependence on the Monticello nuclear plant. O'Neill explained, "What's driving that is the recognition that we need to, over time, wean ourselves off of our dependence on property taxes that Xcel provides — try to become more like other cities in how they operate and pay for things." O'Neill expects that since Xcel Energy announced its intent to extend the life of the Monticello nuclear plant, the urgency to shift to a more user-fee driven funding model may be lessened. However, he sees the shift as good practice for the long-term stability of the city and expects that the city will continue to move that direction.

Monticello Communications Coordinator Rachel Leonard added, "At some point when the plant goes away, we will have to shift to a more typical financial structure. The [City] Council has been very intentional about realizing that, even if the plant is relicensed for another 10 or 20 years, it is in our best interest to start diversifying now. That's obviously not going to happen overnight. It's going to be a big change."

> "What's driving that is the recognition that we need to, over time, wean ourselves off of our dependence on property taxes that Xcel provides — try to become more like other cities in how they operate and pay for things."
>
> —Jeff O'Neill,
> Monticello city administrator

In addition to city service and basic operations, the tax revenue from the Monticello plant helps the City fund infrastructure investments necessary to accommodate growth in the area. O'Neill explained, "The other thing that Monticello has going, because we are in a growing area, we have more demands for debt. We have interchanges to build. We've got sanitary sewer and water lines to construct, roads. There's just more pressure for construction. So having Xcel in the neighborhood really helps us out to soften that."

Monticello has been able to pay for much of its investments in road construction — both maintenance and reconstruction — through its property levy, rather than assessing additional taxes to residents and businesses. O'Neill stated, "Some cities would have charged their property owners through an assessment [for the entire cost of the infrastructure investments], but what we do is we charge some — at least 20%–30% — [through an assessment] but then the rest of it goes on to that general levy. We've had the latitude to do that. That's kind of a hidden benefit of the plant."

Another indirect benefit of the tax revenue that the City receives from the Monticello plant is that residents and local businesses retain more of their earnings, increasing disposable income. "Our public finance system and the way we operate is a bit strange because we have this great property tax wealth that drives the tax rate down," explained City Administrator O'Neill. "That gives us more discretionary money as individuals. Less of our disposable income has to go toward property taxes."

Additionally, average annual base pay for plant employees is above $100,000, significantly higher than the average annual income for the county overall. Commissioner Vetsch stated, "The plant increases the household income in Monticello and the northern part of the county area.… The wages out at the plant are substantially above that of the local community. So it puts our household income far above our peer cities in the county or across the river in Sherburne County." These high-wage workers contribute to the community economically by owning property, spending money in local stores, donating to local nonprofits, and more.

In addition to paying its property taxes, Xcel Energy puts money in a Nuclear Remediation Fund, to which the City and County can apply for funds. "With those funds, they're used for paying for specific pieces of equipment that we would need to respond to a nuclear event. They are useful because the things it funds can be used for other safety needs as well," stated City Administrator O'Neill.

Social Contributions of the Utility and Plant Workers

The Monticello nuclear plant provides more than tax and employment benefits to the community. Through both interviews and survey responses, community members and local officials described Xcel Energy as a good partner, stating that the company plays an important role in the social fabric of the community. One survey respondent stated, "[Xcel Energy is] a good neighbor that supports our community in various ways." Interviewees and survey respondents described how the Monticello nuclear plant enables the community's stable schools, robust volunteerism, and a strong business community.

In addition to the substantial tax revenue the Monticello School District receives from the nuclear plant, it also enjoys a consistently high student population thanks to the plant's workforce. Monticello School Superintendent Eric Olson explained, "Even back into the '70s, '80s, and '90s, Monticello has been a thriving district. At one time, we even had the largest elementary school in the whole state. Being a successful school district can be connected to the power plant and the workforce they bring to our community.…The stability that the power plant has sustained for several decades has provided an amazing structure to keep our district strong. We are proud of our slow, steady growth. And I owe that in large part to the power plant." The consistent growth in student population allows the Monticello School District to maintain stable funding. Superintendent Olson continued, "Consistent growth equates to consistent funding and ultimately gives our district a better opportunity to maintain and retain quality programming for students, staff, and beautiful facilities."

Superintendent Olson continued, "We have a great working relationship with the plant. The plant provides quality jobs for families, as well as expertise and quality volunteers to ensure kids get a great education."

Additionally, the school district partners with Xcel Energy to identify workforce trends and prepare the district's students for emerging opportunities and workforce needs. A representative from Xcel Energy sits on a Wright County Educational Task Force to share the company's perspective and knowledge about emerging job opportunities in the energy field. Superintendent Olson stated, "Xcel also sits on our school committees as well to look at our job force and how the needs of our job force are changing. They've been key partners. They represent a unique business structure. They have everything from entry-level labor positions all the way to professional management and engineering positions."

The Monticello Nuclear Generating Station has also benefited the community's nonprofits and charitable organizations. Xcel Energy encourages its employees to volunteer in the community and allows plant workers to take a day of service for an annual clean-up along the Mississippi River. Last year, plant workers also contributed to a local arts campaign to create a public display at the City's public works facility, which will be used to invigorate the downtown area.

Interviewees noted that plant employees contribute substantially to the local United Way and the local Lions Club. Xcel Energy and its employees are also strong supporters the Monticello Chamber of Commerce. A representative of the Monticello Chamber of Commerce stated, "Xcel is always quick to sponsor our events. Committed volunteers are few and far between these days, but [Xcel Energy] always send[s] staff to our events as well."

Xcel Energy is also a sponsor of the Monticello Riverfest, the city's largest annual summer event. Interviewees indicated that last year, Xcel Energy was integral in securing a well-known band for the event to draw in more people to the city.

Interviewees also noted that Xcel Energy donates to the local Girl Scouts and Cub Scouts, as well as the Chamber of Commerce's Royal Ambassadors Scholarship program, which awards scholarships to young people for volunteering with Monticello events and charitable activities.[20]

City staff noted the importance of Xcel Energy's open and regular communication and coordination with the City. Xcel Energy communicates changes at the state legislature and Internal Revenue Service that affect the Monticello nuclear plant's tax assessments. This communication is critical for City staff and local officials to plan and budget.

[20] "Monticello Chamber Royal Ambassadors Program." Monticello Chamber of Commerce and Industry. Accessed June 25, 2019. http://www.monticellocci.com/list/member/monticello-chamber-royal-ambassadors-prog-monticello-822

Additionally, City staff and Xcel Energy meet quarterly to discuss city and plant news, such as refueling events and ongoing safety efforts and inspections. Refueling events, in particular, have a huge impact on the city's economy. Each event brings 500–800 people to town, who eat, stay, and use local clinics and other facilities for their one-to-two-month visit, which occurs roughly every two years.

Many local retail vendors in Monticello receive a major boost during the power plant's refueling outages. The representative from the Monticello Chamber of Commerce mentioned in her interview that local hotels are often full during these times. The Chamber offers welcome bags to these visitors with information about local restaurants, shopping opportunities, medical clinics, dental offices, and other businesses.

Refueling event

Nuclear power plants typically refuel every 20 to 24 months. At that time, the reactor is shut down and produces no electricity. Workers remove a portion of the used fuel in the reactor, securely store the old fuel, and place some new fuel rods into the reactor. In addition, power plant workers do other preventative maintenance during this time. The utility typically schedules refueling outages during the fall and spring when electricity demand is relatively low.

Swan Park

Shortly after the Monticello nuclear plant became operational, this microclimate attracted five endangered trumpeter swans to over-winter in Monticello. A Monticello community member, Sheila Lawrence, now nicknamed "the Swan Lady," began feeding the trumpeter swans, attracting more and more to join the initial five. Today, over one thousand of the 10-foot-wing-span birds congregate in Monticello during the winter. The swans have become part of the town's identity and a major attraction for visitors. Thousands of visitors come to Monticello to see the trumpeter swans each year, visiting local shops and restaurants. The trumpeter swan is now featured on the City logo and in a large bronze sculpture outside of Monticello City Hall. Xcel Energy and Monticello co-fund the "SwanCam" so that people can watch the swans on a live stream all winter long.[21]

Transition Efforts and Vision

Community survey respondents, nearly all of whom reported that they live and work in Monticello, expressed little optimism about or support for closing the nuclear plant. Respondents said that the power plant provides economic vitality to the community, clean electricity to the state, cheaper utilities for residents, and a great corporate community partner. Similarly, local officials who were interviewed, though they are actively planning and preparing for the plant's eventual retirement, expressed hope that the plant will continue to operate beyond its current end-of-license date in 2030.

A Proposed Extension

As noted above, Xcel Energy's most recent integrated resource plan filing proposed extending the Monticello Nuclear Generating Station's retirement date from 2030 to 2040. Though the proposal does not guarantee an extension of the plant's life — the proposal requires approval by the Minnesota Public Utilities Commission and the federal Nuclear Regulatory Commission — it has lessened the sense of urgency and anxiety around transition planning and efforts for the community. According to City Finance Director Wayne Oberg, "Xcel's [integrated resource plan] reduced anxiety about the plant. Now we can balance infrastructure plans with diversifying our tax base. It no longer feels as dire of an issue."

Even so, the Monticello community will continue efforts to reduce its reliance on the nuclear plant and to diversify City revenue. As discussed above, the City will continue to gradually transition storm water and sewer service as well as garbage collection to user-based fee models. City staff are also discussing plans to incrementally increase residential property taxes to more closely match the average property taxes of neighboring cities. "We're trying to think about the plant retirement as a personal retirement," said City Administrator Jeff O'Neill. "You have to put some money away for the time that you won't have it."

Wright County also expects to continue its preparations for a future without tax revenue from the Monticello nuclear plant. Commissioner Vetsch expects that all of the County's 60-year capital projects will be completed by the power plant's current license expiration date of 2030, meaning that all buildings will have been sufficiently upgraded and retrofitted and the associated debt service will be balanced by that time.

The City of Monticello is also considering the future of the plant site as staff begin a comprehensive planning process. During that process, the City intends to work with Xcel Energy and community members to consider a future in which Monticello is less dependent on the power plant. Interviewees discussed one possible redevelopment opportunity: a river crossing to

[21] "Swan Cam." Fibernet Monticello. Accessed August 8, 2019. http://www.fibernetmonticello.com/swan-cam/

allow for better traffic flow to and from Becker, Minnesota, and along U.S. Highway 10 as well as business development along the corridor.

Nuclear Waste Storage

Any future use of the land on which the Monticello nuclear plant sits may be limited due to the presence of spent nuclear fuel. As noted above, spent nuclear fuel is being stored on-site at the plant. Interviewees noted that the community never expected be a storage site for the plant's spent nuclear fuel. Today, there are roughly 30 dry casks of nuclear waste located at the Monticello nuclear plant. The future of that spent fuel will undoubtedly affect potential future developers' interest in the site.

Local officials and community members alike hope to see progress in relocating or reusing the spent fuel stored at the plant. Monticello City staff participates in the Nuclear Waste Strategy Coalition — a collective of cities, electric power providers, and state regulators that seeks to secure a timely, safe, and cost-effective storage site for nuclear fuel waste in a permanent repository using the federal Nuclear Waste Fund.[22]

One community survey respondent stated, "The power plant in our community plays an important part of our lives. So I sincerely hope to see it continue its operation beyond 2030. Meanwhile, finding a way to recycle its waste will be a great innovative 'renewable energy' concept."

If the Plant Retires

Though Xcel Energy's proposal to extend the life of the Monticello nuclear plant has eased concerns, Monticello residents and local officials expressed significant fears about the future of the community if the plant were to retire. Community survey respondents stated that a power plant closure could result in lost jobs with no comparable replacements, an exodus of residents, reduced resources for the school district, and higher taxes for residents and businesses.

One survey respondent stated, "[If the plant closes,] well paid, educated workers would relocate out of the community, schools would be negatively affected by the loss of taxes, potential loss of students, and loss of a community partner."

Wright County Commissioner Vetsch echoed these concerns, "My main concern is the economic loss of high-wage jobs out of Xcel Energy. Not only would people's taxes go up, but we'd have a mass exodus and a large boom of real estate for houses over $500,000. That those jobs just won't exist in our community, and that will have a rippling effect through our community."

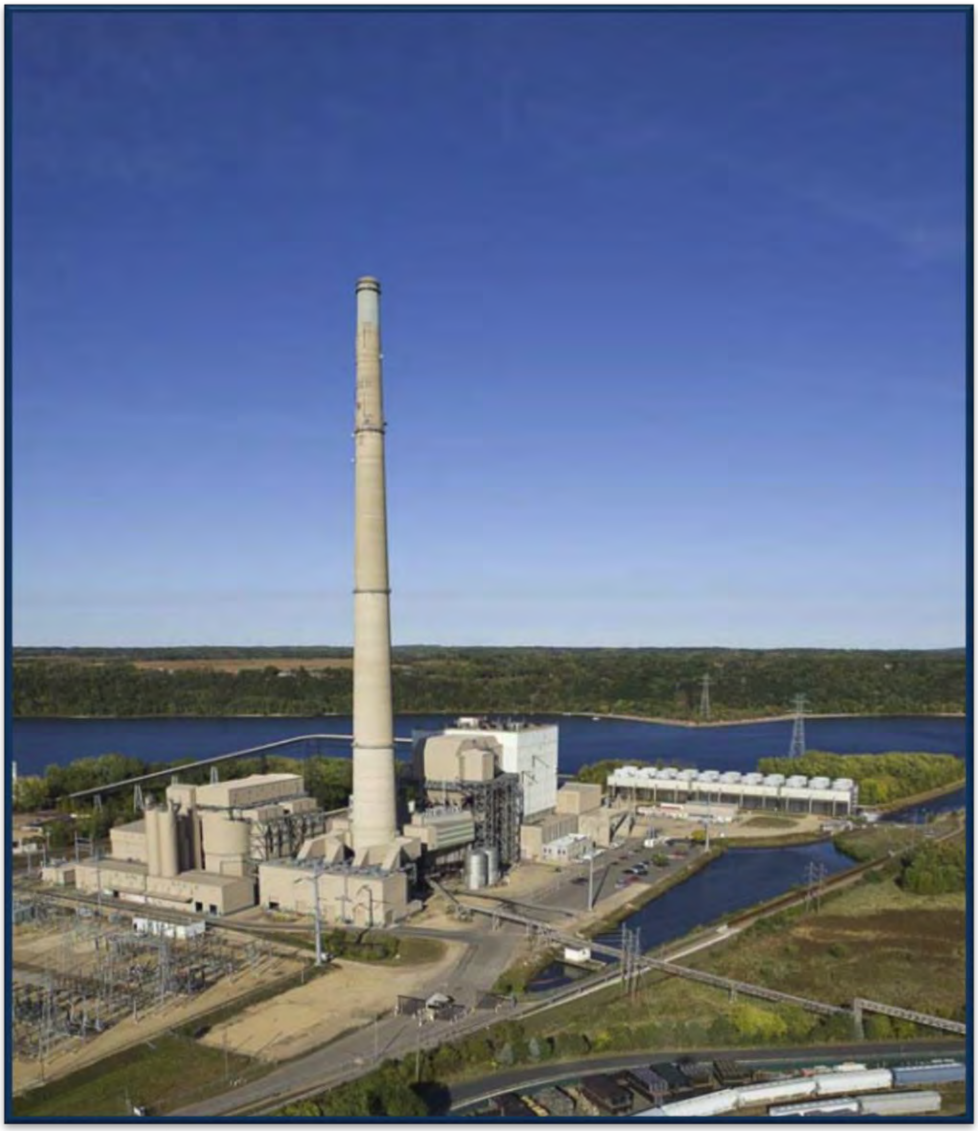
> "How do we even talk about the transition without making people feel fearful? This is just a process and we want to move through as responsibly as possible."
>
> —Rachel Leonard,
> Monticello communications coordinator

[22] "Member Organizations." Nuclear Waste Strategy Coalition. Accessed August 8, 2019. http://thenwsc.org/about-us

Monticello Communications Coordinator Rachel Leonard suspects such fears could actually initiate or worsen transition challenges for the community. Leonard said, “And how do we prevent that from becoming a self-fulfilling prophecy, meaning that uncertainty causes people to feel nervous and anxious.” She continued, “How do we even talk about the transition without making people feel fearful? This is just a process and we want to move through as responsibly as possible.”

Despite the overall notes of concern, some survey respondents and interviewees expressed hope that the community will be able to capitalize on its many assets to diversify the economy and successfully grow even if the plant closes. Community members and some local officials noted the opportunity for the city to become a regional distribution hub given its proximity to the Twin Cities, St. Cloud, and Interstate-94. Interviewees hope to see Sherburne County and Wright County to do more joint regional transportation planning to improve traffic flow and business development. Additionally, interviewees discussed the potential for the Bertram Chain of Lakes Regional Park, which will feature nearly 1,200 acres of natural land, a campground, and a fully off-road triathlon facility, to attract new tourism to the city.

Oak Park Heights



Background Information

Table 5: Allen S. King Generating Station Quick Facts

Power Plant Information	
Power plant fuel type	Coal
Projected closure date	2028*
Generation capacity	511 megawatts
Plant employees	87
Average annual plant employee income[23]	$92,831
City Information	
City population	4,900
% of plant workers residing in city	2%
% of city's tax base from power plant	38%–40%
County Information	
Washington County population	256,348
% of plant workers residing in county	24%
% of county's tax base from power plant	<1%
School District Information	
% of school district's tax base from power plant	5%

*Indicates retirement dates not yet approved by PUC

Oak Park Heights is located in Washington County along the St. Croix River, Minnesota's eastern border, about 25 miles from the Twin Cities. Oak Park Heights has a population of approximately 4,900 residents.[24] Oak Park Heights is home to Xcel Energy's Allen S. King plant, a 511 megawatt coal-fired power plant. The Allen S. King plant was commissioned in 1968 and underwent rehabilitation between 2004 and 2007.[25]

The Allen S. King plant employs approximately 87 workers, 2% of whom reside within Oak Park Heights and 24% of whom reside within Washington County. Utility property taxes from the Allen S. King plant make up approximately 40% of Oak Park Heights' annual city tax base.

The Allen S. King plant would be fully depreciated in 2037. However, in its 2019 integrated resource plan, Xcel Energy proposed that the Allen S. King plant be retired in 2028, nine years ahead of schedule. The proposed early retirement requires approval from the Minnesota Public Utilities Commission.

Findings from Interviews and Community Survey

The study authors conducted a survey and multiple interviews with Oak Park Heights residents, community leaders, and local government officials to gather information about how individuals and organizations are thinking about and planning for the eventual retirement of the Allen S. King coal-fired power plant.

[23] Average annual plant employee income was calculated using 2018 data provided by the utility.
[24] Estimated by the U.S. Census Bureau in 2017.
[25] "Allen S. King Generating Station." Xcel Energy. Accessed August 13, 2019. https://www.xcelenergy.com/energy_portfolio/electricity/power_plants/allen_s._king

Nine Oak Park Heights community members participated in the community survey. In-person interviews with Oak Park Heights local government officials included Oak Park Heights Mayor Mary McComber, City Council Member Chuck Dougherty, City Council Member Carly Johnson, City Council Member Mike Liljegren, County Commissioner Gary Kriesel, Deputy Administrator for Washington County Kevin Corbid, Stillwater Area Public School Superintendent Denise Pontreli, and Executive Director of Finance and Operations for Stillwater Area Public Schools Kristen Hoheisel. Additionally, a local restaurant owner and representative from the Stillwater Chamber of Commerce were interviewed.

By and large, interviewees and community survey participants expressed concern over a power plant closure. Six out of nine survey respondents said they are concerned about the future of the plant as it relates to their community, specifically citing worries about hikes in property taxes, loss of jobs, and higher energy costs. All community respondents except one expect the King plant to close in the near future.

Despite concerns about the plant's future, interviewees and survey participants expressed optimism regarding the potential to redevelop the plant site. Oak Park Heights, though a small city, boasts impressive parks and recreation amenities and is located along the St. Croix National Scenic Riverway. One survey responded wrote, "The land on which the plant stands, located as it is on the river, could be redeveloped for housing, recreation, or other positive social good."

The following describes community members' responses and discussion from the survey and interviews.

Host Community Story

The Oak Park Heights community has had a mixed relationship with the Allen S. King plant over the 50 years it has been in operation. Many survey respondents noted the positive impact that the power plant has had on the community: as a source of significant tax revenue, a job provider, a community partner, and a supplier of reliable electricity. Others, however, noted the unattractive smokestacks along an otherwise scenic St. Croix River and the coal dust and pollution the plant has emitted into the community.

One community survey respondent stated, "[The King plant] donates money to local schools and nonprofits, and taxes paid go to schools." Another community survey respondent stated that the plant provides "tax revenue, employment, [and] business opportunity."

Another community member wrote of the plant, "[It has] ugly smokestacks and coal piles in an otherwise scenic valley." And yet another stated that the negative aspects of the King plant include, "pollution, coal dust, [and] occasional steam blow-offs that alarm residents."

No matter how community members feel about the plant, however, they all acknowledge that it plays an important role in the local economy and feel uncertain about what will happen to the community when the plant retires. Oak Park Heights City Council Member Carly Johnson stated, "I think people are nervous about [the plant closing]. That's the question my neighbors ask me, 'What's going to happen in eight years? How's that going to impact our taxes?' I think people are nervous, but with the lack of information, it's just a wait-and-see game."

Utility Contributions to the Tax Base

As noted above, in 2018, tax revenue from the King plant accounted for approximately 40% of Oak Park Height's city tax base, 5% of the Stillwater School District's tax base, and less than 1% of Washington County's tax base.

For Washington County and the City of Oak Park Heights, tax revenue from the plant goes to general funds and helps pay for basic operations and capital expenses. Deputy Administrator for Washington County Kevin Corbid explained, "Of the units of government here, the county is the least affected. We would likely be able to spread the impact [of a plant retirement] across our tax base without it being apparent." Xcel Energy is one of the largest contributors to Washington County's tax base by dollars. However, the county includes a large part of the Twin Cities metropolitan area, and so the King plant represents a relatively small portion of the county's tax base overall.

For the City of Oak Park Heights, however, the King plant is a major and important source of tax revenue. Tax revenue from the King plant allows the City to maintain basic operations and services, while keeping taxes low for its residents and other businesses. "[Without tax revenue from the King plant], it would [be] an increased burden on our tax payers to pay for the services that we have. It pays for our parks, streets, and other services," stated City Council Member Carly Johnson.

The importance of the plant's tax revenue is heightened because Oak Park Heights is such a small city, with just under 5,000 residents. In Minnesota, cities with fewer than 5,000 residents do not receive municipal state-aid street funding, which is the state's largest source of transportation-related assistance to cities.[26] Oak Park Heights Mayor Mary McComber explained, "We're a city under 5,000, so we don't get any assistance for municipal street aid. So by having the [plant tax revenue], it fills that gap. We also work hard on having a good, long range maintenance plant. Where some cities our size, if they didn't have that tax base, wouldn't be able to keep up the way we have."

Tax revenue from the King plant plays an important, but less direct, role for the Greater Stillwater School District. Tax revenue from the King plant keeps property taxes relatively low for residents in the school district. Interviewees indicated that this likely plays a role in voters' willingness to support additional funding for the school district. Kristen Hoheisel, executive director of finance and operations for Stillwater Area Public Schools, explained, "The more commercial and industrial [tax base], the less that the residential people are taxed. The less residents are taxed, the more opportunity we have to do things in our schools, such as having voter-approved technology, voter-approved improvements to our buildings, and increases to our general fund operation. If residents are paying taxes elsewhere or feeling over-taxed elsewhere, we aren't going to get that money. Remember the schools are the only public entity that has to

[26] August 2019. "Small Cities Assistance." Minnesota House Research. https://www.house.leg.state.mn.us/hrd/pubs/ss/sssmcities.pdf

ask for funding. If we need to do any big initiative, we need our voters to support it." Hoheisel continued, "There's only so many dollars to go around."

County Commissioner Gary Kriesel noted concerns about the need to increase residential property taxes as a result of losing tax revenue from the plant, which could exacerbate another issue plaguing the area — affordable housing. Kriesel stated, "One of the big issues in Washington County is affordable housing and workforce housing. If property taxes start going up, that is not a good thing for affordable housing and workforce housing."

Social Contributions of the Utility and Plant Workers

Xcel Energy contributes to Oak Park Heights and the surrounding community in a number of ways beyond tax revenue. Xcel Energy has helped fund and build a number of community projects in Oak Park Heights and is a significant source of philanthropy for local nonprofits. City and county officials as well as community members describe Xcel Energy as a valuable community partner. One community survey respondent stated, "Xcel is a good community partner in many of the activities and programs that happen in our city."

Oak Park Heights Mayor Mary McComber described one community project for which Xcel Energy played a crucial role, "When Xcel closed the fly ash pit [at the King plant], they turned it over to the City with a $600,000 grant to cover for the fact that we could never build there again. [Xcel Energy] built the first set of trails that went through there at their expense, and then out of that $600,000 we were able to put up the gazebos, benches, and other things. And there is still some money there too. Then the playground that's there was a joint venture from another grant through Playful Cities. And that had to be a community build. We worked with Xcel to get the ground cleared and then we all went together to build the playground."

Mayor McComber went on to describe another project for the Oak Park Heights community funded by Xcel Energy, "Last year, [Xcel Energy] put in pollinator gardens under the transmission lines at their expense. It's beautiful. They've been very good to our city."

> "Xcel is a good community partner in many of the activities and programs that happen in our city."
>
> —Community survey respondent

A representative from the local Stillwater Chamber of Commerce explained, "We're really happy to have Xcel Energy here. They're wonderful to work with…. Xcel Energy is a big contributor [to the Chamber] and there would be a big piece missing if they left."

In addition to the utility's philanthropic contributions, local government officials and community members see the plant as a major source of economic vitality for the community. For example, in the past three years, Xcel Energy has shut down the plant from April to July for planned maintenance. Each four-month maintenance outage brings approximately 400 temporary workers to town to stay, eat, and shop in the surrounding area, giving businesses a boost for the rest of the year.

Pollution and Emissions

Over the years, pollution from the Allen S. King plant has been a concern for Oak Park Heights residents and local officials. Xcel Energy upgraded the plant's environmental controls in 2007 as part of Minnesota's Metro Emissions Reduction Project, significantly reducing mercury, sulfur dioxide, nitrogen oxide, and particulate emissions.

Mayor McComber, also a long time resident of Oak Park Heights, described coal ash from the plant prior to the environmental upgrades, "Everything's a lot cleaner. You can actually eat food out of your garden. I've lived in a lot of houses, but I've never lived in a house before where you can dust at eight in the morning and by 8:10 it looks like you hadn't dusted. And that was with the windows closed."

Since the environmental upgrades were made, the community's concerns about pollution have diminished. Interviewees stated that many in the community have said the air seems cleaner and that the plant is less noisy and disruptive. However, carbon emissions are a concern for some community members. Once community survey respondent stated, "While [the plant's emissions are] EPA controlled, it is a coal-burning plant and, therefore, environmentally not ideal in this time of climate change."

Transition Efforts and Vision

As noted above, in its latest integrated resource plan, Xcel Energy proposed closing the Allen S. King plant in 2028, nine years ahead of schedule. This proposal, while not yet approved by the Minnesota Public Utilities Commission, has increased urgency around transition planning for the community.

"We can't kick the can down the road," said Mayor McComber. "Pretending the elephant in the living room isn't there won't make anything better." While the City waits for the Public Utilities Commission to make a decision on a retirement date for the King plant, the Mayor and other Oak Park Heights representatives are poised to start having conversations about the future of the community and the King plant site.

"We aren't a day early in this," said one local business owner. "We have to start having meetings and dialogue around this and think about what that property could be used for."

Uncertainty and Anxiety

Several interviewees and survey respondents noted that people were overall not well informed about how plant retirement could affect the community or what plans were in place to mitigate the negative effects. One local business owner stated, "It's the sleeping giant in town. We haven't heard the details or the impact it'll have."

When asked what conversations were happening in the community regarding the power plant, a community member said, "It has been fearful. It's been there so long and provided financial support. When you don't know, it's fearful."

Mayor McComber explained that the City is trying to keep community members informed, but is also working with limited information. She stated, "Our city has done a really good job in putting it in our newsletters and getting the word out that we don't have the answers at this time and we aren't going to have them until after this integrated resource plan is done. Then we'll have an idea once the [Public Utilities Commission] says, 'this will be the date.'"

Deputy Administrator for Washington County Kevin Corbid predicts that community members will become more informed and involved once the financial impact of a plant closure starts to affect budgeting and taxation plans for the city, schools, and county. Corbid stated, "Eventually we'll have to start working a plant closure into our budgeting, and that's when it'll hit the public."

To continue to raise awareness and begin a community dialogue, the Stillwater Chamber of Commerce is planning to open one of its regular morning forums, called Toast and Topics, to the public — allowing the City to share information about the potential power plant closure and community members to ask questions and provide input.

Future Use of the Land

The future use of the King plant property was a persistent and hopeful theme throughout interviews and survey responses. The King plant sits along the St. Croix River, which is a designated National Scenic Riverway. The river is an important natural asset for the community, and many community members and local officials hope to redevelop the King plant site in a way that highlights it and its natural beauty.

Interviewees were unanimous and steadfast in their desire that upon a plant retirement, the King plant be fully decommissioned and the land cleaned and restored to be redeveloped for another purpose. Mayor McComber stated, "The worst case scenario is that the plant will just sit there." The Mayor continued, "I would hate to see it be like Granite Falls. They closed that plant and it has been sitting there empty for 15 years. It's just a blighted area. With [the King plant] being on the river, I don't want to see that. I don't think anyone wants to see that."

> "The worst case scenario is that the plant will just sit there."
>
> —Oak Park Heights Mayor Mary McComber

Another interviewee stated, "Empty properties act like a cancer."

Council Member Mike Liljegren expressed surprise that there was a possibility that a plant could sit vacant after retirement. Liljegren stated, "I come from the mining side of the world, and they have reclamation plans set up. When that mine closes, you know exactly what that land is going to look like. I'm surprised that the [Public Utilities Commission] doesn't have that in place."

Interviewees and survey respondents see great promise in the King plant site, once cleaned and restored. Washington County Deputy Administrator Corbid stated, "We've got a power plant on the key unique feature of this area, the river… [When the plant closes] all of a sudden we could have a lot of riverfront. What could it become that could become a real attraction for the city and the region? There's a potential for it to become an unbelievable attraction."

Several interviewees and community survey respondents noted the opportunity to create a recreational area where the King plant currently sits, perhaps paired with a resort property or some other type of lodging. One survey participant said, "[A retirement of the King plant] opens that waterfront to new recreational or nature possibilities." Some interviewees pointed to the river development in the neighboring city of Bayport, Minnesota, which includes a large marina, resort, and recreational area, as a possible example of what the King plant site could become in the future.

Other interviewees expressed an interest in filling the property with another business that could replace some or all of the King plant's tax revenue. Interviewees noted potential industrial uses, including a possible expansion of Anderson Windows, one of Oak Park Height's largest employers.

However, most interviewees indicated that replacing the King plant's contribution to the tax base should not be a driving factor in determining how the land is used in the future. Deputy Administrator Kevin Corbid stated, "You almost have to separate the impact on the City and the use of the land. We have to say we did the best thing and that was the best use of that land. You can't hold out for something that you think will replace that tax base."

Oak Park Heights Council Member Mike Liljegren agreed. "We're never going to get back to what we have [in terms of tax base]. It's about finding the best solution down there and then getting creative with how we're going to move forward."

Given the river's National Scenic Riverway designation, interviewees expect any conversation about redeveloping the King plant site to be complex and include a number of important stakeholders. Washington County Commissioner Kriesel stated, "I think environmentalists will have a very strong voice in how that property will be used in the future." Kriesel indicated that the county will also likely have a strong voice in the conversation, stating, "Washington County views the St. Croix River as a critical resource for us to protect." Other important stakeholders in this conversation will likely include the St. Croix River Association, the Minnesota Department of National Resources, the Army Corps of Engineers, and the National Wildlife Refuge.

You have to turn the clock back to about 1968 when the plant was built. Oak Park Heights accepted [the King] plant and was supportive of [it]. So I think there should be some fairness in spreading that burden through the whole state rather than isolate on one community. If they're going to be successful and get everybody to embrace green energy, then everybody's got to row the boat."

—Washington County Commissioner Gary Kreisel

Additionally, as the land owner of the King plant site, Xcel Energy will be a key stakeholder in the conversation about how that site is used. Washington County Deputy Administrator Corbid stated, "Xcel Energy is the land owner, so we don't know what their plan is. Is there a potential to repurpose it to continue to be a power generator?" Other interviewees questioned whether the site could be used for renewable electricity generation, noting that the transmission infrastructure for power generation already exists at the site.

Support for the Community Transition

Finally, interviewees noted that Oak Park Heights played an important role in providing power throughout Minnesota for many decades. Now that the community is facing a plant closure, interviewees hope the State will help the community through its transition. Washington County Commissioner Kriesel stated, “I would hope the State would recognize the hit that the City and school district are going to take. You have to turn the clock back to about 1968 when the plant was built. Oak Park Heights accepted [the King] plant and was supportive of [it]. So I think there should be some fairness in spreading that burden through the whole state rather than isolate on one community. If they’re going to be successful and get everybody to embrace green energy, then everybody’s got to row the boat.”

Prairie Island Indian Community

Background Information

The Prairie Island Indian Community is a federally recognized Indian tribe under the Indian Reorganization Act of 1934. The tribe's reservation is located on the ancestral homeland of the Mdewakanton Dakota on Prairie Island, which is formed at the confluence of the Vermillion and Mississippi Rivers in southeastern Minnesota. The Mdewakanton, or "those who were born of the waters," have lived on Prairie Island for countless generations. The tribe's land base (including both trust and fee lands) has grown through various federal acts beginning in 1891, and area directly purchased by the tribe now totals over 3,000 acres (including both land and water).[27]

Xcel Energy's Prairie Island Nuclear Generating Station operates immediately adjacent to the Prairie Island Indian Community reservation. Xcel Energy stores spent nuclear fuel in dry cask storage on-site in the Independent Spent Fuel Storage Installation. A full description of the plant is provided in the following section.

[27] "Community: Prairie Island Indian Community History." Prairie Island Indian Community. Accessed July 2, 2019. http://prairieisland.org/community/

There are close to 1,000 members of the Prairie Island Indian Community;[28,] and about 200 members live on the reservation. [29] The Prairie Island Indian Community operates the Treasure Island Resort and Casino on the reservation. The Treasure Island Resort and Casino is a major revenue source for the Prairie Island Indian Community and tribal government, and is the largest employer in the surrounding Goodhue County.[30] The revenue from the Treasure Island Resort and Casino has enabled the Prairie Island Indian Community to maintain financial self-sufficiency. No Prairie Island Indian Community members living on the reservation are employed at the adjacent Prairie Island Nuclear Generating Station. The Prairie Island Indian Community receives no tax revenue from the nuclear generating station.

Xcel Energy has not yet announced whether it will seek to extend the Nuclear Regulatory Commission license for the Prairie Island Nuclear Generating Station. Xcel Energy has stated that it is working with federal authorities to encourage the development of a permanent, off-site storage facility to house used fuel from nuclear facilities around the country as an alternative to its current practice of on-site dry cask storage.[31]

Findings from Interviews and Community Story

The study authors conducted a survey and multiple interviews with stakeholders and leadership of the Prairie Island Indian Community. All five members of the Prairie Island Tribal Council, President Shelley Buck, Vice President Lucy Taylor, Council Secretary Nicci Lehto, Treasurer Johnny Johnson, Assistant Secretary and Treasurer Melanie Urich, as well as the tribe's director of housing Darelynn Lehto, General Counsel Jessie Seim, and the tribe's long-time consultant Heather Westra participated in interviews for this study. Two community members provided survey responses. The following section summarizes the content of those interviews and survey responses.

> "We are the closest community in the entire nation to a nuclear plant and dry cask storage full of spent nuclear fuel — currently there are 44 [casks]. The effects that this community feels are greater than any other community in this nation."
>
> —Tribal Council President Shelley Buck

Host Community Story

Prairie Island Indian Community's host community story is inherently different than all the other host communities included in this report. While residents of the Prairie Island Indian Community live extremely close to the Prairie Island Nuclear Generating Station, not a single member of the tribe works at the plant and tax revenue from the plant goes to the City of Red Wing,

[28] "FAQs: How many Tribal Members are there in the Prairie Island Indian Community?" Prairie Island Indian Community. Accessed July 2, 2019. http://prairieisland.org/faqs/#squelch-taas-accordion-shortcode-content-3
[29] Updated enrollment count provided by a Prairie Island Indian Community representative.
[30] "Home: The People of Prairie Island welcome you!" Prairie Island Indian Community. Accessed July 2, 2019. http://prairieisland.org/
[31] "Nuclear Energy." Xcel Energy. Accessed July 2, 2019. https://www.xcelenergy.com/energy_portfolio/electricity/nuclear

not the tribe.[32] Therefore, the Prairie Island Indian Community does not receive many of the economic benefits typically experienced by communities that host power plants.

The community does, however, experience the negative implications of living next to a nuclear generating facility and its stored spent fuel. The nuclear facility occupies land that once belonged to the tribe, but is no longer accessible or usable to the tribe. Moreover, the tribal community and leadership are deeply concerned about the health and safety implications for residents of living so near to the nuclear facility. Another concern shared by leadership is that there are limited evacuation options for the community in the event of a nuclear incident. Both the reservation and the nuclear plant are located on a peninsula surrounded by the Mississippi River and a large chain of lakes, with only one road that leads out of the area. Additionally, the tribe's sentiment about the plant is inextricably linked to a long and painful history of how the Mdewakanton people have been treated historically.

The Community's History with the Prairie Island Nuclear Generating Station

The Prairie Island Nuclear Generating Station was originally expected to be a natural gas or coal-fired power plant. An article in the November 19, 1958, issue of the Daily Republican Eagle stated that "[Northern States Power] Company [was] planning a million kW steam plant on Prairie Island" in the late 1960s or early 1970s, with no mention of nuclear power.[33] According to the tribe, the Mayor of Red Wing at that time was a proponent of nuclear technology and played a key role in the plant's shift to nuclear fuel.

Prior to the plant's construction, the land it occupies was part of Burnside Township,[34] which was part of the Prairie Island Indian Community reservation. The City of Red Wing and Burnside Township were consolidated into a single City of Red Wing in 1971, which meant that Red Wing then received property tax revenue from the plant. According to interviewees, Northern States Power (NSP), now Xcel Energy, received a right-of-way for a portion of Sturgeon Lake Road (the only road in or out of Prairie Island) from the Bureau of Indian Affairs (BIA) for just over $100. The BIA has a fiduciary role to protect and improve the trust assets of American Indians, Indian tribes, and Alaska Natives.

According to those interviewed, BIA representatives likely never even visited the Prairie Island Indian Community until the 1980s. "Their fiduciary responsibility is to protect the tribe," one

[32] The Prairie Island Indian Community did not receive any financial benefit from the plant until 2003. In 2003, the Prairie Island Indian Community and Xcel Energy entered into an agreement that the company would provide an annual payment to the tribe to be used to purchase additional tribal lands further away from the nuclear plant. Currently, the tribe receives $2.5 million each year. A full description of the settlement agreement can be found in the June 23, 2016, Order by the Minnesota Public Utilities Commission in Docket Number E-002/M-15-922.

[33] November 19, 1958. "Huge Steam Power Plant to Be Constructed by Northern States Power on Prairie Island." *Daily Republican Eagle*.

[34] "Map of Burnside Township: Townships 113 & 114 N; Range 15 W of the 5th PM. [Page 7: Atlas and farmers' directory of Goodhue County Minnesota]." Minnesota Historical Society Collections. http://collections.mnhs.org/cms/largerimage?irn=10221182&catirn=10870072&return=q%3DBurnside%2520Township

council member said. “That doesn’t mean bringing in a power plant next door. Obviously they didn’t do their job, and they still don’t do their job.”

Tribal Council President Shelley Buck explained, “We didn’t have the money or the education to fight this.” Vice President Lucy Taylor went on to say, “Our people had no idea what a nuclear plant was.” Taylor remembered her grandmas selling beads for food. “They were just trying to survive,” she said. “They picked on a community that couldn’t fight back. NSP [at that time] had sited locations in Wisconsin and others — but people raised hell there.”

“Our story is about history and the value of that. Prairie Island is very spiritual. There is a connection we have to the land. It is sacred to the Dakota people. It’s threatened by something we didn’t have a say in.”

—Tribe member, Prairie Island Indian Community

Two of the tribe members interviewed remember the construction of the plant. Vice President Taylor was one of them. “When they first decided to site the plant, the tribe wasn’t consulted at all. We were then told that it would be a steam generation plant. People down here were recruited to help build the thing. I remember my uncle telling me he was excited because it was a job opportunity. People were thrilled to have these labor opportunities. The tribe didn’t have high education — so these were good jobs.”

However, this economic opportunity was only temporary. According to the council members, tribe members were only employed during the construction — they were not offered permanent jobs at the plant after it was finished. Taylor stated, “The day it was done, they were fired.” Vice President Lu Taylor continued, “Growing up, my dad and uncle were given jobs building the plant. They helped build the plant. They were let go as soon as construction stopped. They were not continued on at the plant as others were.”

Plant jobs, or the lack thereof, were important given the economic conditions and lack of economic opportunity in the community. Tribal Council Treasurer Jonny Johnson stated, “The opportunities for our male tribal members were to work on the rail or for [NSP]. I remember when we were struggling to put food on the table. With income [from working to build the plant], I remember the first time we were actually able to buy food.”

“Growing up here, we had to fend for ourselves. Many had to stand in the welfare lines,” Vice President Taylor shared. At the time that the power plant was constructed, the Prairie Island Indian Community had little to no running water or sewer systems and no electricity. Vice President Taylor went on to say that as a result of the poor living conditions, her sister got hepatitis when they were children. “These were the conditions we were living in,” she said. “A lot of people can talk about their childhood and about how good they had it — but not one person who grew up here through the ’60s and ’70s will say that.”

The plant became the community’s backdrop. Taylor and Johnson described the loud sound that came from the steam tower vents, which occurred every other hour, as “terrible.” Two council members noted that the community received a donation to build a playground on the reservation in the 1970s. The playground was located directly under high-voltage power lines coming from the plant. Taylor recalled, "We used to play a game of who could go up the slide the fastest. All of [the playground] was metal, and we'd see who could get up with the least shocks." Johnson added, "As kids we used to think it was funny when you would go down the slide and your hair would stand up straight." Taylor continued, "As a kid, you don't know what's going on."

Children in Prairie Island Indian Community playing on trampoline with nuclear plant in background

For hundreds of years, the land was home to the Mdewakanton Band of Eastern Dakota, ancestors of the Prairie Island Indian Community. One tribal member explained, "Our story is about history and the value of that. Prairie Island is very spiritual. There is a connection we have to the land. It is sacred to the Dakota people. It's threatened by something we didn't have a say in."

There were burial sites on the land, many of which were destroyed or disturbed during construction of the plant. According to the tribal council members, the artifacts and remains that were uncovered during construction of the plant were sent to Hamline University — some, but not all, have since been returned to the tribe. Council President Buck stated, "We have no idea where the objects taken from the site went. People dug up our ancestors. We don't do that to other people." The tribe has concerns over other burial grounds that are located within the boundaries of the plant that have not yet been disturbed, but could be in the eventual decommissioning of the plant.

The Prairie Island Indian Community Today

Today, the community's primary concern is the health, safety, and well-being of tribe members living on reservation land. "We are the closest community in the entire nation to a nuclear plant and dry cask storage full of spent nuclear fuel — currently there are 44 [casks]. The effects that this community feels are greater than any other community in this nation," explained Council President Buck.

The community says their cancer rates have gone up in recent years, particularly of the brain and the thyroid. They worry that the proximity of the plant and the stored spent fuel may be to blame. Johnson said that his sister lives across the street from the plant and all nine of the dogs that she has owned have died prematurely of tumors. "People say our change in diet is the cause," Council Secretary Nicci Lehto commented, "but dogs don't smoke or eat McDonalds. Why do these dogs have tumors too? Especially thyroid tumors are common here."

Being so close to the power plant is a constant source of anxiety for people living on the island. "A lot of people you're interviewing for this study will think about dollars and cents, dollars and cents. For us, it's a different story," explained Secretary Lehto. "There is a psychological impact here. When 24 hours a day you have [the plant] in the back of your mind. When you come out of your home, when you have a barbeque and feel that mist coming off the nuclear power plant — that's a psychological impact. When you lay your head down at night and you have nuclear power plant that's 600 yards away from your pillow.… Wherever you go, the plant is there. You bring a new baby home, you see the plant. You bury your grandma and the plant overlooks it. And yet if it decommissions then you know that your ancestors will be going off to Red Wing — or we don't even know what will happen to them. It's not about dollars and cents. It's about emotions and history and culture and things that cannot be monetized."

According to the tribe, researchers at the University of Minnesota conducted a study in the 1990s to understand the psychological and social implications for children in the tribe living close to the nuclear power plant. Several of the interviewees had children who participated in the study. Vice President Taylor stated, "Our kids were worried that something would happen and there would be no home or parents for them to come back to because of the plant."

Fears of a nuclear accident are heightened because the federal Lock and Dam No. 3 frequently causes flooding in the area, sometimes blocking access to the island's only permanent evacuation route.[35] Darelynn Lehto, director of housing for the tribe, stated, "We have tribal members that don't want to live here because of our flooding and the proximity to the nuke plant." Even aside from flooding, Darelynn Lehto voiced traffic and safety concerns around the roughly 127 families, 300 plant workers, and 1,700 casino employees attempting to leave the island at once in the event of an emergency.

[35] In 1938, the U.S. Army Corps of Engineers built Lock and Dam No. 3, which flooded Prairie Island Indian Community land, reducing the tribe's livable area and creating a larger floodplain.

In 2018, the Federal Emergency Management Agency conducted its biennial Emergency Response Drill exercise at the Prairie Island nuclear plant, the results of which bore significant implications for the community. The drill exercise, which centered around a leak scenario, revealed that the Prairie Island Indian Community would be left in an "exclusion zone" in such an event, displacing tribe members, residents, employees, and businesses for two years. The exclusion zone included the Treasure Island Resort and Casino, which is the community's livelihood, the largest taxpayer in Goodhue County, and the second biggest hotel in Minnesota. An incident at the plant would threaten not only the health and safety of tribe members, but also their prosperity.

> "If the plant closes, the tribe should take back that land and the state and federal government should clean the site up and restore the land."
>
> —Darelynn Lehto, housing director for Prairie Island Indian Community

In the past, Xcel Energy has not always notified the community of emergencies that occurred at the plant. In mid-1979, a tube ruptured in a steam generator at the plant and an emergency was declared. Workers were told to evacuate the facility and island. In interviews, members of the tribe recalled seeing vehicles from the plant kicking up dust as they sped off the island, only to learn much later that that an emergency had been declared. Again in 2008, a chlorine gas leak from a steam generator forced
a 12-hour evacuation at the plant. The tribe was notified of this incident right away, but off-site news stations called it a radiation incident, and some schools shutdown, adding to the general confusion.[36]

The community's relationship with Xcel Energy has improved dramatically in recent years. Members of the tribe expressed feeling more informed about refueling events, possible incidents, and other updates. Tribal President Buck said that now, she is able to call or text the current regional President of Xcel Energy, Minnesota, South Dakota, North Dakota, Christopher Clark, directly when she needs to. He also visits the community regularly to meet with the Tribal Council. One council member said, on the tribe's current relationship with the utility, "Now our communication is a lot better. What was it like in the past? Terrible! It was horrible."

Vision for the Future

Ideally, the tribe would like to see the plant decommissioned, the nuclear waste removed, and land restored to its original state and returned to them. "If the plant closes, the tribe should take back that land and the state and federal government should clean the site up and restore the land," said Housing Director Darelynn Lehto.

Removing the nuclear waste from Prairie Island is a critical component of the tribe's vision for the future. The tribe wants to see all of the nuclear waste currently stored on Prairie Island moved to a permanent repository, as promised by the federal government during nuclear energy's proliferation in the 1960s and 1970s. However, the council members are wary of a

[36]"Nuclear Positions: Prairie Island Nuclear Power Timeline." Prairie Island Indian Community. Accessed October 22, 2019. http://prairieisland.org/policy-positions/nuclear-positions/#squelch-taas-accordion-shortcode-content-0

plant closure because they understand the challenges of relocating nuclear waste. Secretary Lehto expressed concern that if the plant closed before a new storage location has been established, there would be less attention paid to maintaining and ultimately removing the spent nuclear fuel being stored on-site.

Another important part of the tribe's vision is that the remaining burial mounds remain protected if the plant is decommissioned.

Continued communication from Xcel Energy is also very important to the tribe. Darelynn Lehto explained, "I would expect Xcel Energy staff to staff community meetings with the Prairie Island Indian Community and to manage the community relations and let them know directly what's going on. It would ease a lot of the tension that currently exists because of [Prairie Island Indian Community] being left out."

The community would also like to see more research studies into the short-term and long-term health implications of living so close to a nuclear power plant and nuclear waste storage.

Finally, the Prairie Island Indian Community's future vision includes the entire community relying on net-zero carbon energy. The tribe has already hired a consultant to model strategies required to reach this goal, which would include demand response, energy efficiency, and solar photovoltaic developments on site. The tribe is particularly interested in adding solar over the parking lots of Treasure Island Resort and Casino.[37] The tribe is seeking funding from the Renewable Development Account (RDA) via the Minnesota legislature. The state legislature requires Xcel Energy to pay $500,000 per year per storage cask at the Prairie Island plant (and $350,000 per cask per year stored at Monticello) into the RDA. Grants are awarded out of the RDA to fund innovative renewable energy projects. Thus far, the Prairie Island Indian Community has not received any grant funding from the RDA. One council member said, describing the community's hopes for the future, "We would like to see the tribe obtain RDA funds so that [we can] transition to net zero."

[37] Orenstein, Walker. April 3, 2019. "The Prairie Island Tribe wants to get to net-zero emissions. Its biggest roadblock may be house DFLers." *MinnPost*. https://www.minnpost.com/environment/2019/04/the-prairie-island-tribe-wants-get-to-net-zero-emissions-its-biggest-roadblock-may-be-house-dflers/

Red Wing

Background Information

Table 6: Prairie Island Nuclear Generating Station Quick Facts

Power Plant Information	
Power plant fuel type	Nuclear
Projected closure date (unit respective)	2033, 2034
Generation capacity	1,100 megawatts
Plant employees	600
Average annual plant employee income[38]	$109,023
City Information	
City population	16,500
% of plant workers residing in city	31%
% of city's tax base from power plant	54%
County Information	
Goodhue County population	46,304
% of plant workers residing in county	39%
% of county's tax base from power plant	22%
School District Information	
% of school district's tax base from power plant	40%

[38] Average annual plant employee income was calculated using 2018 data provided by the utility.

Red Wing is located on Minnesota's eastern border in Goodhue County, along the Mississippi River, about 60 miles from the Twin Cities. Red Wing has a population of approximately 16,500.[39] Red Wing is home to the Prairie Island Nuclear Generating Station, which has two pressurized water reactors that generate about 1,100 megawatts combined. The Unit 1 reactor started operating in 1973, and the Unit 2 started operating in 1974.[40] The two units are licensed with the Nuclear Regulatory Commission to operate through 2033 and 2034, respectively.[41]

Xcel Energy built a dry cask storage facility at Prairie Island in 1995, which also operates under a license from the Nuclear Regulatory Commission. The Minnesota Public Utilities Commission approved on-site storage of up to 64 casks and other equipment needed for storage. Currently, the storage facility holds 40 casks.[42]

The Prairie Island Nuclear Generating Station employs approximately 700 plant workers, 31% of whom reside in Red Wing and 39% of whom reside within the county. Utility property tax revenue from the plant makes up about 54% of Red Wing's annual tax base.

Xcel Energy has not yet announced whether it will seek to extend the Nuclear Regulatory Commission license for the Prairie Island Nuclear Generating Station. If the plant's license is not extended, the Prairie Island Nuclear Generating Station units would close on or before 2033 (Unit 1) and 2034 (Unit 2). Xcel Energy has stated that it is working with federal authorities to encourage the development of a permanent, off-site storage facility to house used fuel from nuclear facilities around the country as an alternative to its current practice of on-site dry cask storage.[43]

Findings from Interviews and Community Survey

The study authors conducted a survey and multiple interviews with Red Wing residents, community leaders, and local government officials to gather information about how individuals and organizations are thinking about and planning for an eventual retirement of the Prairie Island Nuclear Generating Station.

Twelve Red Wing community members participated in the community survey. In-person interviews with Red Wing's local government officials included Red Wing Mayor Sean Dowse, Goodhue County Commissioner Paul Drotos, Red Wing School District Superintendent Karsten Anderson, and Red Wing's Administrative Business Director Marshall Hallock. Interviews with

[39] Estimated by the U.S. Census Bureau in 2017.
[40] "Prairie Island Nuclear Generating Station." Xcel Energy. Accessed July 15, 2019. https://www.xcelenergy.com/energy_portfolio/electricity/nuclear/prairie_island
[41] "Nuclear Energy — A Clean Energy Future." Xcel Energy. Accessed July 15, 2019. https://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/PI_license_renewal_fact_sheet_external.pdf
[42] "Nuclear Energy." Xcel Energy. Accessed July 15, 2019. https://www.xcelenergy.com/energy_portfolio/electricity/nuclear
[43] "Nuclear Energy." Xcel Energy. Accessed July 15, 2019. https://www.xcelenergy.com/energy_portfolio/electricity/nuclear

Red Wing community members included two local business owners and the leader of a local arts nonprofit.

Without exception, Red Wing interviewees and community survey participants emphasized the many assets of the Red Wing community. From its scenic bluffs and riverfront to the iconic Red Wing Shoes company and Lock and Dam No. 3, Red Wing residents find a lot of reason to love their city, as well as its engaged volunteer network, small-town feel, and vibrant arts community and economy. While the Prairie Island nuclear plant is not directly responsible for those community assets, it has played a significant role in making the city what it is today. "I don't know Red Wing before the plant," said Marshall Hallock, Red Wing's administrative business director. "You have generations that have spent careers there. It's hard to compare Red Wing to what it was before that."

Community survey participants and interviewees expressed mixed optimism and concern over the Prairie Island Nuclear Generating Station's approaching end of license date. The following describes community members' comments and discussion from interviews and survey responses.

Host Community Story

Utility Contributions to the Tax Base

Tax revenue from the Prairie Island nuclear plant makes up a significant portion of Red Wing's city and school district tax bases, as well as Goodhue County's tax base. That revenue amount, however, has fluctuated significantly over time. In the early 2000s, tax revenue from the plant was at a low. Legislative reforms to the State's property tax system and changes at the Department of Revenue for utility valuation rules, along with normal asset depreciation, resulted in Xcel Energy paying significantly less in property taxes for the plant. In 2012, Xcel Energy began making significant investments in the plant, replacing the generators and other original components as well as improving safety features.
The market value of the Prairie Island plant doubled from 2012 to 2017, and its property tax obligation increased dramatically.[44]

As noted above, today revenue from the plant accounts for approximately 54% of the City of Red Wing's property tax base, 40% of the Red Wing School District tax base, and 22% of the Goodhue County tax base. The plant's tax revenue primarily goes toward expenses related to general operation for the city, county, and schools. However, the City is using some of that tax revenue strategically to invest in upgrading and renewing its aging infrastructure.

> "The cost of roads and bridges keeps increasing.… A mile of pavement costs about a $1 million and we have over 400 miles. Climate change is already creating issues. We had roads this spring that exploded from flooding. That's a concern when 22% of the county's revenue won't be there eventually."
>
> —Goodhue County Commissioner Paul Drotos

[44] "Red Wing 2040." City of Red Wing. Accessed August 9, 2019. http://www.red-wing.org/DocumentCenter/View/509/Red-Wing-2040-Powerpoint-PDF

According to Red Wing's Administrative Business Director, Marshall Hallock, "A significant portion [of taxes received from Xcel Energy] go to fund daily operations, cops, firefighters, just guys like me that are funded out of the general fund. But a more significant thing that our taxes are funding are all the capital projects that we've undertaken to try to position the community for success going forward."

Prior to the recent major upgrades to the nuclear plant, nearly all the tax revenue the City received from Xcel Energy went to the general fund to pay for daily operations. Today, the previous base of tax revenue from the plant still goes to the general fund for basic operations. However, the additional revenue that the City receives as a result of the upgrades goes toward significant capital renewal and investments. The City is investing in its infrastructure and paying down those investments today in preparation for the power plant's eventual end of license.

It is important to note that Minnesota cities face limitations on saving tax revenue to use in future years. Hallock explained, "It would make sense for us to keep levying and stockpile a war chest to use in the future. We're not allowed to do that. What we do is levy on current year expenses." He continued, "It comes up a lot as I talk to the public, 'Well, why don't you put aside a bunch of money right now?' But we can't over-levy to put a bunch of money away for future years. The state auditor would come knocking." Given that limitation, rather than saving money for future use, the City is buying down debt associated with its investments in infrastructure.

"The City gets credit for investing now and taking advantage of the revenue they have," said County Commissioner Drotos. "The City knew in advance that Xcel would invest in the plant and that would increase the plant's valuation," explained the Commissioner, who previously worked at Xcel Energy and more recently served as Red Wing's environmental officer. "They also knew that infrastructure was crumbling. They decided to make investments while Xcel was still contributing to the tax base."

Hallock elaborated on the strategy, "We're trying to invest in capital assets without increasing our operating expenses." This includes redoing the streets, fixing water and sewer mains, fixing public buildings with leaky rooves, and investing in building efficiency to lower costs. "We don't want to wait until the Xcel tax base is gone and this work falls solely on residents. Red Wing took on debt to invest in all this, but we'll have paid it off in the next eight years."

Commissioner Drotos said this is a model he hopes to bring to Goodhue County. "The cost of roads and bridges keeps increasing," he said. "A mile of pavement costs about a $1 million and we have over 400 miles. Climate change is already creating issues. We had roads this spring that exploded from flooding. That's a concern when 22% of the county's revenue won't be there eventually."

The Prairie Island nuclear plant also contributes substantially to Red Wing's school system, and though the school district would not see a shortfall in funding if the plant retired, the amount of school funding currently provided by Xcel Energy would fall to residents and local businesses. The school district recently passed a $22 million referendum to upgrade facilities over the next eight years, while the power plant's property taxes are available. "Xcel is paying 40% of that [referendum amount]. If Xcel wasn't here, then everybody else would have to pay the debt service payments," explained Red Wing School District Superintendent Karsten Anderson. He went on to say that where the tax revenue for the school district comes from is important for maintaining support for continued funding for Red Wing's schools. "If Xcel wasn't here, it absolutely would have lessened the chances of that [referendum] passing."

Superintendent Anderson also discussed the impact of potentially losing students in the district due to a plant closure, noting that a lot of the plant employees have kids in the district. "If the plant closed, it would have a dramatic impact on the school district. And as the school goes, so goes the community. People move to better districts so the housing market crashes and the economy dominos."

Social Contributions of the Utility and Plant Workers

Survey respondents and interviewees stressed the vital role that power plant employees play in the Red Wing community. According to data provided by Xcel Energy, approximately one-third of Prairie Island nuclear plant employees live within the city of Red Wing. These employees are highly skilled and paid well-above the area median, providing both economic and social benefits to their community. During one interview, a local business representative stated, "Having a nuclear power plant brings in an educated workforce to the community with a six-figure salary."

These highly educated and highly paid employees invest in their own properties, spend money at local businesses, and support local government investments in schools, infrastructure, and advanced technology. "The plant employees have created residual value in the community by investing in their homes and properties. That won't go away overnight," said Goodhue County Commissioner Paul Drotos. "Xcel brings people into the community that demand better education and services. For example, Red Wing was early to expand internet technology in the area. It's a progressive community."

> "If the plant closed, it would have a dramatic impact on the school district. And as the school goes, so goes the community."
>
> —Red Wing School District Superintendent Karsten Anderson

Additionally, Xcel Energy and Prairie Island nuclear plant employees provide vital support for Red Wing's local nonprofit organizations, including the United Way of Goodhue, Wabasha, and Pierce Counties; Hispanic Outreach; Every Hand Joined; and the YMCA. According to one survey respondent, "As a nonprofit leader, my agency benefits greatly from [Xcel Energy's] commitment to community. It would be devastating to the community to lose them." This survey participant went on to say that if the nuclear plant closed, several local nonprofits would likely have to close their doors as well, noting that this would result in a gap in the services that they currently provide for the community.

Interviewees specifically discussed the substantial contributions that Xcel Energy and its employees have made to Red Wing's strong arts community. "From an arts perspective, [Xcel Energy is] a great partner," said Mayor Sean Dowse. "Over the years, they've given thousands a year in ticket subsidies for students and kids to go to Sheldon Theatre matinees." Xcel Energy also donates annually to Red Wing Arts, a nonprofit with the mission to support an arts culture and appreciation for the work of local artists.[45] According to Red Wing Art's Executive Director Emily Guida Foos, Xcel Energy makes up 5%–10% of many local organizations' total revenue. "Everywhere you look, Xcel Energy and Red Wing Shoes are the two funders," Guida Foos said. "Without them, other organizations wouldn't have the confidence to contribute funds as well."

The power plant and its workers also support local businesses in town. "Plant workers have been here for so long and are so integrated to the community that it's hard to know what Red Wing might be like without the plant. There are small businesses that work with the plant and may not even acknowledge how much they rely on it," commented Superintendent Anderson. Interviewees noted that welding shops and other trades and businesses receive significant revenue from the power plant. However, the exact economic value provided to local business is hard to quantify. "Even think about Red Wing Shoes. Everyone at that plant needs a pair of steel-toe boots," noted a Red Wing business owner.

Other Important Community Considerations

Interviewees as well as nearly all survey respondents discussed Red Wing's shortages of housing, particularly for affordable housing, and childcare. Though these issues are not directly connected to the Prairie Island nuclear plant, they constrain current and future economic growth opportunities. "We're behind on workforce housing," Mayor Drowse admitted. "Employers are consistently down 20 people for hiring, and Treasure Island Casino is down a hundred. Some people who want to live here can't find a place to live."

With a growing population of retired residents, some of the City's efforts to attract a new generation of workers and diversify its economy have been stymied by the lack of housing. "Housing variety doesn't exist here," said one interviewee. "What you're looking for doesn't exist, or if it does, you have to be the first one there because it will sell."

When asked about the greatest needs in their community, one resident responded, "Affordable housing, affordable childcare." Another respondent reiterated the point, "Our community is very short on housing for lower-income workers and childcare."

Transition Efforts and Vision

As discussed above, Red Wing is already preparing for an eventual plant retirement by using some of the tax revenue it receives from the plant to strategically pay down infrastructure investments while the revenue is available. It is important to note that while this strategy may reduce the need for a future tax increases to pay for capital investments in infrastructure, it does not address a loss in revenue for general operations. The City, County, and school district will still have to address a significant loss in funding along with a number of other issues if the Prairie Island plant retires.

[45] "Our Mission & Vision." Red Wing Arts. Accessed October 7, 2019. https://redwingarts.org/mission-vision

Nuclear Waste Storage

As noted above, spent nuclear fuel is stored on-site at the Prairie Island facility. Many interviewees and survey participants noted concerns about the future of that nuclear waste. Study participants recognized the challenges of relocating the stored spent fuel given federal inaction in developing a permanent storage facility and noted concerns related to future land use options and redevelopment opportunities. “The community would be very upset if the spent fuel was indefinitely left there. A huge concern of the community is if Xcel leaves, what happens to the waste? Will they just leave it here?” stated one community member interviewee.

The City of Red Wing is actively looking for options to remove and relocate the stored nuclear waste. “We’re participating in any venue we can to remove that waste,” said Hallock. This includes participating in the Nuclear Waste Strategy Coalition, a collective of cities, electric power providers, and state regulators that seeks to secure a timely, safe, and cost-effective storage site for nuclear fuel waste in a centralized interim storage facility or a permanent repository using the federal Nuclear Waste Fund.[46]

In a separate interview, Mayor Dowse stated that relocating the spent nuclear fuel was a top priority. In thinking about the potential for extending the plant’s current license, he recognized the difficult situation that the Prairie Island Indian Community faces with respect to the stored nuclear waste. “They don’t want to see 40-plus storage casks 600 yards from them. It should be tough for the state to tolerate that too … and even Red Wing may have a problem with it.”

Diversifying the Economy

The City of Red Wing is considering ways it can attract new businesses and community members to diversify its reliance on the power plant for tax revenue. The City’s 2040 Comprehensive Plan references its heavy tax dependence on the Prairie Island nuclear plant and the need to consider a future without that revenue source. In all interviews and survey responses, there was a general sentiment that business diversification is possible and essential going forward. “The impact [of a potential plant closure] is going to be there regardless,” said one community member interviewee. “It’s what can you do to blunt that. Expand employment and diversify employment. Make Xcel a smaller piece of the economy as a share.”

> “Together, we’re going to have to figure out with Xcel and the State how we will survive this.”
>
> —Red Wing Mayor Sean Dowse

Many interviewees agreed that Red Wing’s creative community and scenic setting has the potential to attract innovative new possibilities to the city. One survey respondent offered a suggestion, saying, “Tourism should be strengthened [in Red Wing] with a more integrated approach to recreational assets and the creative economy.” The Mayor hopes to see new businesses emerge and grow from the local Minnesota Southeast Technical College campus. He also stated that he would like to see more immigrants settling in Red Wing to support new industries and enjoy the natural and cultural amenities the area has to offer. “Small cities in cold

[46] “Member Organizations.” Nuclear Waste Strategy Coalition. Accessed October 7, 2019. http://thenwsc.org/about-us

climates, as I understand it," he elaborated, "need a strong immigrant community to stay vital. We've got to get over this idea that immigrants are a threat. Immigrants are going to save this country, as they always have."

The City of Red Wing also sees itself continuing to play an important role in Minnesota's clean energy economy. County Commissioner Drotos said, "I would like to see a resurgence of people who are hungry for knowledge, education, and success come to Red Wing. The clean energy economy can come here. The security, infrastructure, and the workforce are all here. I think we are poised for a technological economy in the energy field — maybe nuke, maybe something else. I'm not in favor of replacing [the Prairie Island plant] with gas. That reactor is going to be done when it's done, but there are other things out there."

Mayor Dowse also said that he hopes to keep the City's strong relationship with Xcel Energy. "We don't ever want to lose them. We want to help Xcel reach their carbon goals and we want them to reach 100% carbon free by 2050. Nuclear has got to be a part of that for baseload power."

Uncertain Future

According to the City, its biggest obstacle in planning and implementing its transition strategy is uncertainty. While the community holds a resounding hope that Xcel Energy will seek to relicense the Prairie Island nuclear plant, there is no guarantee that the company will or that such a request would be approved by regulators. The Prairie Island nuclear plant's license is not discussed in Xcel Energy's current integrated resource plan filing, so the community will have to wait for the next resource plan for an update. City Business Administrator Hallock commented, "I will welcome a decision on the plant either way so that the city can have certainty. Once a decision is made, it will mobilize the community."

"Together, we're going to have to figure out with Xcel and the State how we will survive this," said Mayor Dowse.

SECTION 3: POWER PLANT WORKERS AND ORGANIZED LABOR

Power Plant	International Brotherhood of Electrical Workers	Building Trades	Total Permanent Unionized Plant Workers	Short-term Maintenance Workers
Sherburne County Generating Station	250	50	300	150–200
Boswell Energy Center	116	0	116	10
Monticello Nuclear Generating Station	185	15	200	230
Allen S. King Generating Station	75	10	85	75–100
Prairie Island Nuclear Generating Station	322	69	391	230

Power plant workers will be the individuals most affected by a power plant retirement. Plant workers, whether direct utility employees or employees of contractors, devote their careers to working in and on power plants. Power plant jobs are typically specialized, high paying, and stable — an increasingly rare combination in today's economy. Workers and their families face great uncertainty around power plant retirements regarding how, and even whether it will be possible, to replace their jobs and incomes. Recognizing this, the study authors conducted interviews with the labor unions that represent power plant workers. Labor unions represent their members in negotiations with employers on a wide range of issues and also provide members with training and job placement and relocation support.

Interviews were conducted with the International Brotherhood of Electrical Workers, Laborers' International Union of North America, and the International Brotherhood of Boilermakers to better understand the perspective of power plant workers and the effects that Minnesota's energy transition has on them. The following description of interviews with labor unions aims to illuminate their perspective and the effect that a power plant closure may have on workers and the unions that represent them.

International Brotherhood of Electrical Workers

The International Brotherhood of Electrical Workers (IBEW) is a labor union that represents electrical industry workers in the United States and Canada, including plant operators, wiremen, line workers, and other employees of public utilities. Five different IBEW local unions represent workers in each of the five Minnesota power plants included in this study. Representatives from each of those five locals participated in an interview for this study.

IBEW local unions represent hundreds of workers across these five power plants. IBEW members are high-skilled workers who have spent two to four years in apprenticeships with additional training and education throughout their careers. Typical occupations for IBEW members in Minnesota power plants include electrical maintenance workers, equipment operators, plant engineers, instrument and controls technicians, and coal yard workers.

IBEW's leadership and membership pay very close attention to proposed and approved power plant retirement dates. The majority of full-time workers in Minnesota's utility-owned power plants are members of the IBEW. Thus, IBEW's local unions, members, and members' families will be among the most affected by power plant retirements in the state. "In short, anyone working full-time at the plant is likely an IBEW member," summarized one IBEW representative. "We're the ones that will be most affected," another representative said. "We're in those plants 24/7."

"We're the ones that will be most affected," another representative said. "We're in those plants 24/7."

—IBEW representative

IBEW's top concern regarding power plant closures is the loss of jobs for its members. Similarly, IBEW's top priority in the face of a power plant closure is ensuring that all of its members retain or find employment in jobs that allow them to maintain the same quality of life as they had in their previous position. That includes comparable wages, benefits, and hours, as well as a working location that allows members to return to their homes and families between shifts. As Minnesota reduces the number of central power plants in the state, the union's effort to transition laid-off workers to similar positions within other plants will become increasingly difficult. Moreover, the high-quality jobs within utility-owned central power plants — in terms of pay, benefits, and stability — are exceedingly rare elsewhere in the energy industry and as well as outside of it. Moving potentially hundreds of laid-off workers to positions of comparable quality outside of power plants would also prove challenging.

Strategies for Dealing with Plant Closures

Most of the union's business representatives and managers interviewed for this study have experience with power plant downsizing or closure in the past. "Our number one goal is to place those members so that they are gainfully employed and not laid off." Another representative added, "So far we've been successful in doing that." However, most of the previous closures with which the union has experience modeling and negotiating agreements were smaller plants. The pace and scale of Minnesota's current energy transition will strain the union's traditional strategies for managing layoffs.

During small or more isolated plant closures, the union would often seek out similar positions for members in other utility-owned power plants. That strategy is less viable in the face of multiple plant retirements in a similar timeframe, with far fewer replacement plants coming online. "A machinist at a coal plant could be a machinist at a nuclear plant. In the past, we had options to move people to other sites. We don't have that anymore," said one representative. The Boswell plant representative stated, "Boswell operations folks are highly knowledgeable, but if they can't move to another plant with some sort of boiler, there's little value to their skill set. If you're a plant operator, there are very few opportunities for you unless you get retrained."

> "In the past, we had options to move people to other sites. We don't have that anymore."
>
> —IBEW representative

Retraining can be an option for plant workers who face layoffs and may be an especially good fit for younger workers who have years or decades of time to pursue a new career. However, investing in additional years of retraining may be unattractive for workers who are nearing retirement. IBEW's goal is to ensure that workers who are retraining are doing so for jobs of comparable quality to those they are leaving. IBEW indicated that they do not know of opportunities for members to retrain for comparable quality jobs outside of the industry, and electric utility positions are decreasing in number overall.

Another strategy of the unions is to move workers from one state to another for work in their specialty. This is also becoming less effective, as states across the country are facing the same energy transition as Minnesota, moving away from centralized generating plants toward more renewable energy resources. Even when possible, this strategy of moving workers across states is typically a last resort because it requires families to relocate.

Retention bonuses can assist workers who face future layoffs and also help keep experienced staff on the job and plants operating smoothly through plant retirement. IBEW representatives stated that they have asked Xcel Energy about retention bonuses for workers at plants slated for retirement, but that the utility has not yet engaged in those conversations. "[Retention] will be a problem," one representative explained. "If people say 'we have to save ourselves' then you'll have an inexperienced workforce operating the plant." Experienced, knowledgeable operators are needed at a plant site until the very last day of operation. Workers who stay through plant retirement, however, may be more likely to experience a gap in employment.

IBEW and both utilities involved in this study have agreed to some wage protections for workers in the event of a plant closure. However, any further wage protections, job transfers, or support for workers will be determined through future negotiations. As one representative noted, "Ultimately, [the utilities] have to bargain the effects of any closure with the unions."

Workers Nearing Retirement

Approaching closure dates for Minnesota's regulated power plants creates special challenges for workers nearing retirement age but not yet able to retire. "[One] of the biggest issues we face is that people will be 50 years old when the plant closes. They invested their whole career and retirements into those plants." These workers will not have earned full or sufficient retirement benefits and may be limited in the types of jobs they could transition to as well as opportunities to retrain for a new role. Based on proposed and approved retirement dates for the power plants in this study, IBEW representatives expect that there are a significant number of workers who fall into this category.

One union representative for the Allen S. King plant stated, "[Members are] nervous because if the plant goes in 2028 or sooner, I'm going to have about 47 people or so that are 50 years old and need seven to eight more years to finish up." A representative for the Sherco plant estimated that if the plant retired in 2030, as proposed by Xcel Energy, about 95 people would have one to 10 or more years left before they could retire with full pension.

One representative explained, "If I'm 50 years old, my pension will be crap. After 50, your average earnings would be higher, and that's where most of your retirement is built up. It's like a hockey stick [graph]." Another representative added, "They'll still get their retirement, but it's going to be a much smaller pension than what they would have had. So their lifestyle will have to change dramatically."

Additionally, the uncertainty around power plant closure dates makes career and retirement planning difficult for workers. The representative from the Boswell plant stated, "At Boswell, we have daily conversations with members that view [plant retirement] as a moving target. Minnesota Power wanted to keep [Boswell's Unit 1 and Unit 2] open longer but the [Public Utilities Commission] had them shut down sooner because the investments were so costly to keep it running. It's hard for [workers] to make career decisions because seven years earlier makes a big difference."

Transferring workers who are nearing retirement age to other open positions at the utility can pose challenges as well. One representative noted, "You take a guy that's 50 years old that has been an operator his whole life, and now you're going to move him to the line or construction. It's going to be way more physical. To learn how to be climbing polls at age 50, you tell me how that's going to go."

Worker Opportunities in the Energy Sector Going Forward

To date, IBEW has yet to see evidence that the clean energy industry will replace the number and quality of jobs associated with utility-owned power plants. Interviewees cited several reasons for this. First, the utilities often buy solar and wind farms after construction with a five-year contract for continued maintenance with the third-party developer. IBEW representatives noted that often these are built with nonunion labor and therefore are maintained by nonunion workers. Second, solar and wind fields require very few permanent jobs for operation and maintenance. The majority of jobs associated with wind and solar are temporary jobs during the construction process. One representative stated, "Permanent green jobs are essentially a myth." He continued, "Minnesota Power put up 500 megawatts of wind and through that we gained four members. Most was built in North Dakota largely with nonunion workers and is still staffed nonunion."

"You take a guy that's 50 years old that has been an operator his whole life, and now you're going to move him to the line or construction. It's going to be way more physical. To learn how to be climbing polls at age 50, you tell me how that's going to go."

—IBEW representative

The IBEW representatives admitted that they have been caught off guard by the pace of Minnesota's transition toward wind and solar generating resources. "Clean energy really started getting pushed around 2005. Everyone thought it couldn't be done, yet here we are and half of the plants in Minnesota are gone."

As a result of diminishing jobs in energy generation, some union representatives expect their membership to downsize and to potentially merge with other locals. "Local 23 will go down through the attrition," one representative said of the union representing workers at the Allen S. King plant. Others responded with, "We'll have to make decisions on increasing members' dues or look at merging with other locals, because we can't sustain that number and still serve the membership," and, "it will dramatically affect all of us."

Support for Workers and Communities

IBEW members expressed hopes that Minnesota's energy transition would include support from utility employers for IBEW members in finding gainful, quality employment. "Give them a soft landing and make sure they get retrained," one interviewee said. Other interviewees hope that clean energy organizations that have advocated for closing power plants would offer support for dislocated workers. Another representative suggested that there should be a state program offering a two-year degree to retrain workers displaced from power plant closures at no cost to workers.

The representative for the Boswell Energy Center mentioned that the Iron Range Resources and Rehabilitation Board (IRRRB) could offer a good model to draw upon. The IRRRB has a retraining program for when manufacturing facilities or mines close. Instead of a property tax, these companies pay a production tax on what they extract or produce. Some of these taxes are then allocated for retraining and assistance for dislocated workers.

IBEW interviewees also discussed the interconnectedness of impacts on workers and the communities that host retiring power plants. "It's going to be a huge issue for the communities," one representative stated. "Now towns will have to pick up property taxes within those [host] communities. And if our people are still living there, and they do find employment elsewhere, they're going to have lower wages and they'll be paying more in taxes. That's going to change those communities."

Laborers' International Union of North America

The Laborers' International Union of North America (LIUNA) represents workers in the United States and Canada. LIUNA members reflect a diverse array of workers that specialize in the construction and energy industries. In the context of power plants, LIUNA's workers are involved with building and decommissioning plants, nuclear refueling outages and dry cast storage, retrofitting plants for upgraded safety or for a natural gas conversion, as well as building renewable energy resources like wind and solar. The business manager of a LIUNA local union participated in an interview for this study, and a regional representative for LIUNA provided written input.

LIUNA represents hundreds of workers who are employed with utilities, including Xcel Energy and Minnesota Power, and has a running contract for all of Xcel Energy's power plant facilities.

This contract covers LIUNA members who are direct employees of Xcel Energy, in Xcel Energy's special construction department, as well as employees of specialty construction contractors who work on Xcel Energy facilities. In total, LIUNA estimates that 300–400 of its members work as an Xcel Energy employee or employee of a contractor. One LIUNA business manager said regarding their members' roles on-site at power plants, "Our laborers are there first and they're there last." Because of this, LIUNA's locals in Minnesota work closely with utilities and track their integrated resource plans to keep apprised of potential power plant closures and the resulting implications for their members.

Energy Transition and Changing Opportunities

Given the nature of LIUNA's members' work, they have the benefit of some continued opportunity even as large central power plants retire. As plants are either decommissioned or retrofitted, LIUNA expects to see a significant, albeit temporary increase in the amount of work available to its members. Nonetheless, working to build and upgrade fossil fuel and nuclear power plants is a significant source of work for LIUNA members. If power plants are decommissioned and not replaced, work opportunities for LIUNA members could diminish substantially over time.

In the face of these diminishing opportunities in fossil fuel and nuclear plants, LIUNA is trying to think about the future and act proactively. The local union representative stated, "We take an 'all of the above' energy approach." Both LIUNA's local and national unions are working to transition members to the renewable energy field, where they see an opportunity for union market share to grow. LIUNA's local representative stated, "As plant closures come down, and jobs go away after decommissioning, how do we ensure that our members have jobs on the renewable energy side? We want to make sure that our members on the fossil side that are losing jobs are able to maintain good-paying union jobs on the renewable side. We are trying to work with Xcel to ensure that that opportunity is available."

LIUNA is especially interested in wind energy, which necessitates much more work for laborers than solar photovoltaic developments due to licensing and electrical codes. Locally, LIUNA coordinates and communicates with the operators, ironworkers, and millwrights' unions to say aware of upcoming and ongoing wind farm developments.

> "[Developers] are bringing in a lot of out-of-staters, nonunion to build wind farms. They don't have prevailing wage attached to them, so they don't pay the area standard."
>
> —Local LIUNA representative

Despite the opportunities that may come in the renewable energy sector, a lot of uncertainty remains. According to LIUNA's local representative, its members' biggest concern about power plant closures across the state is the loss of good, family-sustaining jobs. As the largest building and construction trade organization employed by Xcel Energy, LIUNA representatives are concerned that their members could disproportionately lose in Minnesota's energy transition. "A lot of our members at Xcel are very concerned about their jobs. They don't know what will happen when these jobs change," one LIUNA representative stated.

A major driver of uncertainty and concern for LIUNA and its members is that clean energy jobs have so far not been a one-for-one replacement for utility-owned power plant jobs. Even utility-scale renewable energy projects have often been built with non-local and nonunion labor. This affects both LIUNA members and Minnesota's local communities and workforce more broadly. The local LIUNA representative described, "We are trying to gain market share in the renewable industry, where much of it has been done nonunion. A lot of projects are not benefiting communities where they're being built in regard to jobs. [Developers] are bringing in a lot of out-of-staters, nonunion to build wind farms. They don't have prevailing wage attached to them, so they don't pay the area standard. They are undercutting."

Recently though, LIUNA has seen increased local hiring for Minnesota's renewable energy projects. The regional LIUNA representative stated, "[It's] been changing rapidly thanks to hard work on both sides. We've seen significant efforts on the part of both utilities and clean energy developers to do a better job of creating high-quality opportunities for local workers. By our estimates, we've gone from a wind construction workforce that was less than 20% local (Minnesota or within commuting distance of project) in 2017 and 2018 to more than 60% local in 2019, and we expect the trend to continue into 2020."

Community Impacts

The local LIUNA representative, whose father was a union member who worked at Xcel Energy plants for nearly 30 years, spoke from personal experience describing the benefits that he, his family, and his community have experienced from the high-quality jobs and the tax base that utility-owned power plants provide. "Xcel Energy built up this whole area," he stated. "That's how I grew up. I had a very good childhood because we didn't necessarily want for anything. I had healthcare. I never had to worry about that. Xcel itself has sustained thousands of households in our communities."

He went on to commend Xcel Energy for its ongoing work in the community, "In my mind it's incredibly important that as they brought forward this plan to shutdown Sherco early they have made an effort to help redevelop that area." He went on to say, "However, the businesses that are moving in aren't all using union contractors. If those were Xcel projects, they would have been ours. So these aren't just transitioning over one-for-one quality jobs."

> "[It's] been changing rapidly thanks to hard work on both sides. We've seen significant efforts on the part of both utilities and clean energy developers to do a better job of creating high-quality opportunities for local workers."
>
> —Regional LIUNA representative

He spoke of one company that is considering moving into Becker, Minnesota — home to the Sherco Generating Station — with plans to power its facility with renewable energy. But the existing wind farm slated to serve that business was built with nonunion labor outside of Minnesota.

Regarding communities' economic transition as power plants retire, the local LIUNA representative stressed the importance of maintaining well-paying jobs. "As the redevelopment happens, it's important that we take note of the jobs that we're losing and ensure that we're replacing them with well-paying jobs. When you're competing on costs the easiest way to compete is paying your employees less. [LIUNA has] a standard we set for all of our contractors to pay. This is something that has to be at the forefront of these jobs and the renewable energy economy coming in."

LIUNA's Hopes for Minnesota's Energy Transition

What does a successful transition look like for LIUNA members? First, LIUNA hopes that the plant sites do not stay idle for long periods of time before decommissioning. When the site contains an abandoned building, not only have people lost their former jobs, but no new jobs are transitioned into its deconstruction. "Leaving a plant dormant does very little for us," the LIUNA representative said. Further, as plants are decommissioned, LIUNA hopes "that Xcel will self-perform that work."

More broadly, LIUNA hopes that state regulators, policy-makers, and Xcel Energy do as much as possible to ensure that energy infrastructure creates local jobs. LIUNA would like to see "the [Public Utilities Commission] attach a prevailing wage requirement to new [renewable energy] projects. The local labor hire reporting requirements were a big step in the right direction." Though LIUNA workers and contractors have an advantage over many other contractors — providing a more skilled workforce, which increases productivity and safety — it can be difficult to compete against contractors using low-paid, low-skilled, and often non-local workers for some contracts that focus primarily on cost.

Boilermakers Local #647

Founded in 1936, the Boilermakers Local #647 (Local 647 or Boilermakers) is located in Ramsey, Minnesota, and serves Minnesota, North Dakota, and South Dakota. Local 647 is a construction lodge of the International Brotherhood of Boilermakers, Iron Ship Builders, Blacksmiths, Forgers and Helpers.[47] Local 647's membership includes about 550 workers that that do a substantial amount of contract work in power plants, including all of the plants included in this study. Two representatives of the Boilermakers Local #647 participated in an interview for this study.

Members of Local 647 are highly trained with a very specialized skillset. Members go through a four-year apprenticeship and training program and graduate to become certified welders and certified crane riggers, with ongoing education throughout their careers. While members work in industries and facilities other than the energy industry and power plants, about 75% of members' work hours happen in power plants. Local 647 members' work in power plants includes everything from erection to dismantling, repairs, tube work, and work on environmental controls, bag houses, scrubbers, ducts, and stacks. Boilermakers are not direct employees of the utility. They perform work in power plants as employees of contractors.

Given the amount of work Local 647 members do in power plants, as well as the highly specialized nature of their work, power plant retirements are top of mind for Local 647

[47] "About Us." Boilermakers Local #647. Accessed October 11, 2019. http://boilermakerslocal647.com/about-us/

leadership and members. "The members themselves keep up on the current events as to what Xcel is saying, the latest plan," said one representative.

The Effects of Closing Plants

The representatives interviewed said that their biggest concern regarding plant closures is the loss of work and livelihood for members. Local 647's members are relatively young. According to the Local 647 representatives, the average age of its members is about 37 to 38 years. This is important, as most of Local 647's members will not be at retirement age when many of the plants included in this study are expected to close.

The Boilermakers are already seeing a decline in work due to power plant closures. One representative stated, "It's already on the decline. [Utilities] have a date out there when they know they're going to shut down [a plant] and their tendency is just to not spend any more money on them than they have to. That's been happening for a couple of years now." Reduced hours for Boilermakers in the electrical sector is happening alongside a decrease in work at a major Minnesota refinery as well. As work dwindles in both of these key areas, Boilermakers are seeing fewer available positions and work hours, and less and less opportunity in the future. "Take a Boilermaker that's been in for six, seven, eight, maybe 10 years looking at his career disappearing before his eyes," said one representative.

"We're already being impacted by [plant retirements] heavily. There's a loss of man-hours, the average hours per year per member is declining. We have people leaving the trade and looking for work elsewhere."

—Boilermakers representative

Another representative explained, "We're already being impacted by [plant retirements] heavily. There's a loss of man-hours, the average hours per year per member is declining. We have people leaving the trade and looking for work elsewhere." The power plant work has good pay and benefits, which helps support the entire union membership. The alternative work opportunities, however, are not equal replacements for the lost work in power plants. "Unfortunately [members are finding other work] in places that pay less with crummier benefits, which also affects our pension fund." Members who are looking for jobs outside of power plants are in many cases moving toward shop work, which pays less than power plant work.

As opportunities decline, Boilermakers face a shrinking membership as well. Some members are leaving the Boilermakers and moving to other trades and others are working in nonunion positions in local shops. Recruiting new members is becoming more difficult as well. "We're having trouble bringing new people into the apprenticeship program," one representative stated.

Worker Opportunities in the Electric Sector Going Forward

According to the representatives interviewed, Boilermakers have few to no opportunities associated with renewable energy resource development or maintenance. The specialized work that Boilermakers do does not apply to renewable generation. They do not anticipate that the construction or maintenance of additional renewable generation in the region will benefit their members.

When asked if the Boilermakers would have any opportunities from decommissioning work when a power plant retires, they emphasized the short-term nature of those jobs. According to the representatives, decommissioning work is short lived and does not lead to future prospects for members, but rather forecloses an opportunity. “It’s like getting a piece of granite and asking you what you want written about you on your tombstone,” one representative said of opportunities related to decommissioning.

The representatives stated that the Boilermakers do have some work opportunities in the construction and maintenance of natural gas plants. To the extent that retiring coal and nuclear plants may be replaced with or converted to natural gas-fired power plants, the Boilermakers may see continued opportunities in the electric sector. However, they still expect to see a significant decline in work in the sector, even if additional natural gas plants are brought online. The representatives explained that natural gas power plants require significantly fewer workers and work hours from their trade compared to coal and nuclear plants. “The problem with a gas plant is that you might have 50 to 60 guys for about a year, and then it’s done, and we might go back in for maintenance and it’d be six to eight guys for a week. Compared to maintenance at a plant like Sherco, where you have 100 guys a shift with two shifts for five to six weeks every year or every other year.”

> “The idea of green jobs is a lie. They are including all sorts of things in there like decommissioning or little projects and calling them jobs. Those aren’t jobs, those are temporary projects.”
>
> —Boilermakers representative

Both representatives expressed concern about what will happen to host communities that lose plants. One representative stated, “The loss of highly skilled highly paid jobs, the economic impact is going to be devastating.” The representatives interviewed were skeptical about the quality of employers and jobs that may replace power plants. “Do they pay $60 an hour, total package? I’m pretty sure they don’t,” one representative said. He went on to say, “Even on the wind turbine and solar side, the vast majority of what’s being built is being done by nonunion companies using low-wage scales. The contractors are from down south or out west, so all the dollars leave the state.”

The representatives also expressed skepticism and concern about power reliability if all the plants included in this study were to retire in a short timeframe. They believe it is unrealistic to think that all the plants in this study could be replaced with renewable energy resources without major outages during peak winter and summer periods.

Support for Workers

When asked what types of support the Boilermakers hope to see for workers, one representative stated, “The type of support that our members would like to see is a job, and therein lies the big issue. When they are closing the plants for green energy, it’s going to wipe us out." He continued, "There's going to be a gross loss of jobs due to this [energy transition] that aren't coming back. There is no green job that's going to replace this stuff, and that's not just for the Boilermakers, it's for all of power generation and a lot of other crafts too and support businesses."

One representative stated, "The idea of green jobs is a lie. They are including all sorts of things in there like decommissioning or little projects and calling them jobs. Those aren't jobs, those are temporary projects. You're creating something that lasts two weeks long and giving it a credit like you would a permanent job."

The representatives do see opportunity for their trade and members in carbon capture and sequestration technology. "I'd like to see [utilities] build new [coal] plants with carbon capture on them." The representatives mentioned a project in North Dakota that will add carbon capture technology to an existing coal plant. A representative stated, "The vast majority of carbon capture work would go to [Boilermakers]."

> "The type of support that our members would like to see is a job, and therein lies the big issue. When they are closing the plants for green energy, it's going to wipe us out."
>
> —Boilermakers representative

However, the representatives worry that political opposition to coal may be too strong in Minnesota for carbon capture technology to truly take off. "The biggest misconception out there is that coal is dirty. Boilermakers have been putting the pollution controls on these plants for decades." The representatives believe that carbon capture technology could be the next generation of environmental controls for coal plants and would like to see greater attention paid to the technology and its potential in the state.

Finally, the representatives interviewed would like to see greater communication and consideration for the Boilermakers as plans are developed around the future of power plants and any related workforce plans or support. The Boilermakers will be greatly impacted by power plant closures in the state, but so far have not been included in the conversation around plant closures. "[Xcel Energy] never asked for input from us," stated one representative.

SECTION 4: FINDINGS AND CONCLUSIONS

1. Power plants have played an important role in building vibrant and stable communities across Minnesota. Power plant closures will undoubtedly have a strong economic and financial impact on the communities that host them, and potentially, other Minnesota communities as well.

The power plants included in this study have been instrumental in helping to build many of the communities in which they are located. Through interviews and survey responses, community members and local government officials stressed the many contributions of the power plant to their communities. Power plants are so intertwined with the communities that they call home, community members and officials struggle to even imagine what their community would be like without the plant.

Power plants contribute directly to a community by providing a stable, healthy tax base; utility contributions to local charities and nonprofit organizations; contributions to local parks and recreational investments; and commerce with local businesses that serve the plant. Plants contribute indirectly by attracting plant workers and their families to these communities, which includes new businesses and commerce to serve workers and their families, the contributions that workers and their families make to the community through charitable giving and volunteering, and the value that workers and families build through investments in their own homes and property. Additionally, power plant jobs are typically relatively high-paying and stable, with good benefits. These jobs help to build stable families within power plant communities and the surrounding areas.

The power plants included in this study also contribute to other nearby communities and, more broadly, the region in which they are located. The property tax revenue that power plants provide helps to fund important state aid programs like the Local Government Aid program, the Fiscal Disparities program, and the Department of Iron Range Resources and Rehabilitation. These programs provide aid to communities that need additional funding to meet residents' needs. Power plant communities contribute significant revenue to these programs, while receiving little or no funding in return, which benefits other communities and the region. For more detailed information about these state and regional financial aid and taxation programs and how Minnesota's host communities contribute, see **Appendix B: Key State Financial Policies**.

Given the important contributions that power plants make, power plant retirements will result in significant impacts on Minnesota communities. Host communities will have to shift more of their tax burden to residents and other businesses. Local charities and nonprofits will need to look elsewhere for revenue that once came from the utility and power plant workers. Residents and businesses may also face fewer or different job or business opportunities. Other communities throughout the state may also face financial impacts due to shifts in revenue and breakdown of recipients and contributors for state financial aid programs. The degree to which communities experience the economic and social impacts of a power plant closure will depend on a number of factors, such as proximity to other economic and employment opportunities, trends in the regional economy, and the success of local economic development efforts.

Other power plant communities across the nation that have faced power plant closures offer a glimpse at what Minnesota's host communities could also experience when their power plants retire. These communities across the nation and the strategies they employed throughout their transition may also be informative as Minnesota considers how to manage the impact of power plant retirements. **Appendix D: Literature Review of Transitioning Power Plant Communities** of this report contains a literature review describing the experience of four different communities across the country that are facing or have faced a power plant retirement, along with key takeaways from those communities' transitions that may be relevant and useful for Minnesota.

2. Minnesota's host communities are currently pursuing a range of strategies to plan and prepare for power plant closures as well as the economic transition those closures will require. None of those strategies are expected to fully offset the economic impact of a plant closure, but they may help mitigate the negative effects.

Many of the Minnesota communities included in this study are proactively planning and preparing for the eventual retirement of the power plants they host. These host communities are currently deploying a number of different strategies to assist with their forthcoming economic transition. Through interviews, local government officials stressed that, given the magnitude of the tax revenue associate with power plants, they do not expect that their efforts will fully replace the benefits currently provided by the power plants. However, they hope that a combination of their own strategies and efforts, along with some other potential future efforts at the state and regional levels, may help mitigate the effects of a power plant closure and allow their communities to continue to grow and prosper.

Some communities included in this study are investing to renew and revitalize their aging infrastructure now, with the aim to pay those investments off before the power plant retires and they lose its tax revenue. Other communities are investing in infrastructure to attract new businesses, such as preparing shovel-ready industrial parks, and actively working to recruit new businesses. Some communities have plans to develop recreational areas that highlight the natural assets of the community to attract new visitors and tourists. Nearly all of the communities included in this study noted plans to engage community members on issues related to transition planning, whether through comprehensive planning efforts or public discussion forums.

Appendix D: Literature Review of Transitioning Power Plant Communities of this report provides a description of some of the strategies that other communities facing power plant retirements have deployed to mitigate the effects of their plant closure.

3. Planning and preparing for a community transition related to power plant closure requires a long time horizon.

Many strategies that Minnesota communities may want to employ to mitigate the impacts of a power plant closure are long term in nature and require years to fully execute. This was a common theme throughout a number of interviews with local government officials.

For example, economic development projects may require significant planning, zoning changes, infrastructure investments, and long-term business recruitment or development efforts. Similarly, investing in and paying down debt for infrastructure renewal for a city, county, or school district ahead of a power plant retirement requires significant time for planning, construction, and debt service. Additionally, negotiating a community transition package amongst a diverse range of interested stakeholders can take years, as was the case for the Diablo Canyon Nuclear Plant, discussed in **Appendix D: Literature Review of Transitioning Power Plant Communities**.

The earlier communities begin planning and deploying transition strategies ahead of plant retirements, the more likely it is that those strategies mature and provide benefits to the community.

4. Uncertainty or a lack of information around the timing of a power plant closure poses additional challenges for a community's planning and preparation.

Unknown, uncertain, or changing timelines for a power plant retirement can make community and worker transition planning more difficult. Several local government officials, community members, and labor union representatives discussed the hardship associated with transition planning and preparation when a plant retirement date is not known or changes.

When plant retirement timelines seem uncertain or unknown, it can be difficult to know how and when to select and implement effective transition strategies. Moreover, if a retirement date is accelerated significantly, it may mean that transition plans and efforts will not be fully effective in time for the plant's closure. This, in turn, increases the likelihood that the community and plant workers will experience negative economic and socioeconomic impacts from a closure.

Additionally, uncertainty around power plant retirement dates can affect how communities and workers respond to and prioritize the need for transition efforts. When a date is unknown or perceived to be uncertain, it may be difficult to galvanize support for investing in effective economic transition strategies. Moreover, unknown, uncertain, or changing timelines for a plant retirement can exacerbate anxiety and tension for plant workers, host community members, and local government officials, making it more difficult to reach agreement, build support for, and carry out a community and worker transition plan.

Some uncertainty regarding power plant retirement dates is unavoidable. Minnesota utilities and the Minnesota Public Utilities Commission must make resource decisions, including determining plant retirement dates, in response to changing plant, economic, and policy conditions. However, some uncertainty may be avoided or lessened by ongoing and open communication between the utility, regulators, communities, labor unions, and workers. Open and frequent communication may also increase levels of trust and cooperation in developing and implementing transition strategies.

Appendix D: Literature Review of Transitioning Power Plant Communities includes examples of how communities have responded to and experienced uncertain or changing power plant retirement dates and how some communities developed strategies to facilitate communication and information-sharing to improve transition planning and implementation.

5. Land use and redevelopment of power plant sites after a plant has closed is an important issue for Minnesota's host communities.

Through interviews and community survey responses to this study, local government officials and community members expressed great interest in how the property currently occupied by a power plant will be used after the power plant retires. Community members and local officials voiced concern about retired power plant sites remaining vacant, as well as hopes for using the land that their power plant currently occupies in new ways after the plant retires.

Almost without exception, the Minnesota host communities included in this study stressed that once their local power plant retires, they do not want the shuttered plant to remain on-site. Study participants expressed hopes that when the local power plant retires, the utility owner will fully decommission the plant and remediate the property. Study participants noted concerns about leaving a closed plant in place, including the inability to redevelop that land for other valuable uses and that the retired plant building and property could become a blighted, problem property.

Many study participants expressed hopes about using the current power plant property for other purposes after plant retirement. In some cases, participants hoped to see the power plant property land cleaned and restored to its natural state to be enjoyed by the community, and potentially to attract tourists and visitors as well. In other cases, participants hoped to see the land redeveloped for other business purposes to provide economic value to the community. Several participants also noted the opportunity to use the existing power plant property to site new energy resources, which could then use the existing transmission and distribution infrastructure from the current plant. Interview participants discussed the need to balance the best use of the power plant property with the desire to use the property to bring in additional tax revenue.

Appendix D: Literature Review of Transitioning Power Plant Communities provides examples of how some power plant communities facing a plant retirement in other parts of the country have addressed decommissioning, remediation, and land use of power plant properties after retirement. The case of Centralia, Washington, provides an example of how decommissioning and remediation efforts can be designed with the future land use in mind to manage costs and take advantage of existing infrastructure.

Nuclear spent fuel storage will present serious challenges for decommissioning, remediation, and redevelopment of power plant property for some Minnesota host communities. Study participants from communities with a nuclear power plant expressed concerns about the stored nuclear waste staying on-site indefinitely even after a plant closed. Participants voiced a number of questions and concerns about how and by whom stored nuclear waste will be secured, maintained, and monitored if the plant retires. The Prairie Island Indian Community, where residents live closer to stored nuclear spent fuel than people do anywhere else in the country, expressed concern that if their local nuclear plant closed, political and public attention to addressing the spent nuclear fuel waste could wane, leaving them with a permanent problem and little support.

With no federal permanent or interim storage option available, nuclear spent fuel storage has remained unmoved from plant sites in other parts of the country for decades after plant retirement and decommissioning. **Appendix D: Literature Review of Transitioning Power Plant Communities** describes the experience of Wiscasset, Maine, where a nuclear plant retired in 1997 and stored nuclear waste remains at the plant site to this day.

6. Minnesota plant workers, the unions that represent them, and the host communities have shared interests and concerns regarding power plant closures. Workers, labor unions, and host communities may benefit from close coordination and communication in plant closure transition planning and preparation efforts.

Minnesota's power plant workers and power plant host communities are closely connected in terms of their relationships with their power plants. In some cases, workers and host communities are indistinguishable, as plant workers are often members of the host community.

Host community members and local government officials discussed the importance of power plant workers to their communities. Power plant workers often own property in their host community, send their children to local schools, pay taxes, give to local charities, and volunteer. One local official of a host community even stated that their biggest fear in facing a power plant closure was not lost tax revenue, but the prospect of plant employees leaving the community.

Similarly, the labor unions that represent power plant workers expressed the importance of the host communities to workers and workers' families. A major issue for workers facing a power plant retirement is the prospect of uprooting their families and moving away from the host community to find employment opportunities elsewhere.

In many ways, host communities and power plant workers face a shared fate around power plant retirement. Workers, labor unions, and host communities may find value in collaborating, coordinating, and supporting one another throughout community and worker transition efforts.

Appendix D: Literature Review of Transitioning Power Plant Communities provides examples of organized labor and host communities that worked together to achieve community and worker transition agreements in response to a power plant closure.

7. In today's economy, power plant jobs are uniquely high in quality. There are no clear options to replace power plant jobs with positions that are similar in terms of pay, benefits, stability, and location.

The labor unions that represent power plant workers emphasized the high quality of power plant jobs and the difficulty, if not impossibility, of replacing those power plant jobs with jobs of equal quality. Labor union representatives noted the relatively high pay, the stability of employment, the good benefits, and the location of power plant jobs. In each interview with representatives of organized labor, they stressed that it is critical to think beyond simply replacing a total number of jobs when considering plant worker transitions. Rather, one must consider the quality of the jobs available to plant workers who are displaced due to a power plant closure.

Power plant jobs are career positions. Power plant jobs are often high-skilled positions that require extensive apprenticeships and training, which can take years to complete. Accordingly, power plant jobs pay relatively high wages, well above Minnesota's state median income. Table 7 provides a comparison of the average annual base wages for workers at each of the power plants included in this study to the Minnesota median average household income.

Table 7: Annual Power Plant Wages Compared to the Minnesota Median Income

Power Plant	2018 Average Annual Base Wages per Power Plant	2014–2018 Minnesota Median Household Income (2018 Dollars)
Sherburne County Generating Station	$88,556.39	$68,411[48]
Boswell Energy Center	$88,317.25	
Monticello Nuclear Generating Station	$108,990.86	
Allen S. King Generating Station	$92,830.97	
Prairie Island Nuclear Generating Station	$109,023.41	

*Note that the Minnesota median income figure refers to a household, while the power plant wages refers to the individual.

Power plant jobs are very stable with a low risk of elimination due to outsourcing or other factors. Additionally, power plant jobs provide high-quality benefits, including a retirement pension. This is notable as, according to the Bureau of Labor Statistics, only 17% of private industry jobs offered a retirement pension plan in 2018.

The combination of pay, stability, and benefits make power plant jobs uniquely high in quality in today's economy. These jobs allow for workers to provide financial stability for their families and to invest in their communities.

As more of Minnesota's central power plants retire, power plant workers facing job loss due to plant retirement likely will not be able to simply move to a different power plant within the state. In fact, as power plants retire across the country, even workers willing to move out of state will be less likely to find open positions at power plants. Far fewer permanent workers are needed for natural gas power plants, and even fewer are required for renewable energy resources. Therefore, as Minnesota transitions toward more renewable energy resources and natural gas generation, the total number of jobs in the electric generation sector will decline.

[48] "Minnesota Compass." U.S. Census Bureau. Accessed January 28, 2020. https://www.census.gov/quickfacts/fact/table/MN/INC110218#INC110218

It will not be easy to replace power plant jobs with jobs of equal quality, and indeed, it is not clear if it is possible. This is especially true in communities facing economic downturns in other important local industries.

8. Not all of Minnesota's host communities receive benefits from the power plant they host.

The Prairie Island Indian Community's relationship to the power plant they host is distinctly different from that of any other community in this study. Their relationship with the nuclear plant is rooted in decades of history, including how the plant came to be, the history of the land on which the plant sits, how the tribe was treated during construction and early operation of the plant, and how the utility communicated with the tribe.

Moreover, despite its proximity to the plant, the Prairie Island Indian Community does not receive tax revenue from it, and no tribe members work at the plant. The nuclear plant and on-site spent fuel storage deters many community members from living on tribal land. Additionally, the nuclear plant is seen as a threat to the tribe's main source of income, the Treasure Island Resort and Casino, in the event of a nuclear incident.

Today, the Prairie Island Indian Community and Xcel Energy have open communication and the relationship is as good as it has ever been. Nonetheless, the tribe does not receive many of the economic and social benefits of hosting a power plant that are typical of the other communities included in this study. The community does, however, experience the negative aspects of hosting a power plant.

The Prairie Island Indian Community would like to see the plant retired, the land restored to its previous condition, and returned to tribal ownership. However, they acknowledge that this is likely unrealistic until the spent nuclear fuel stored on-site is removed.

APPENDIX A: STUDY METHODOLOGY

Literature Review

This study began with a literature review of existing resources and research about community transitions due to power plant closures. This included resources on the "just transition" framework, academic journal articles on lessons learned from transitioning communities, and technical reports regarding environmental remediation after plant retirements. Citations for those resources are provided in the bibliography of the literature review.

Through this broad research, the study authors selected four specific case studies of power plant closures in the United States. Authors reviewed these case studies and summarized that research herein to illustrate how community transitions have unfolded under different sets of circumstances, as well as the challenges and opportunities that emerged. The case studies reflect two nuclear power plant retirements and two coal-fired power plant retirements. The authors researched each of the four community transitions through a variety of sources; wrote a summary description of the transition stories, highlighting key takeaways that may be informative for Minnesota's communities; and received and incorporated input on the summary descriptions and key takeaways from national experts who are familiar with each of the transition stories.

The information gathered through the literature review informs the findings and conclusions included in this report.

Qualitative Research

The study authors convened a Steering Committee of community representatives from each of the host communities included in this study, a representative from each of the utilities included in the study, and a representative from the Coalition of Utility Cities.[49] The Steering Committee helped shape and guide this study by and providing input on desired outcomes, providing their expertise on local issues, and drawing upon their local networks. The community representatives included mayors, city administrators, staff from economic planning and development departments, and a community liaison to the Prairie Island Indian Community.

The Steering Committee and the study authors determined the qualitative methods for this study would include an online community survey that was sent to approximately 10 members of each host community, as well as in-person, group interviews with local governmental officials and experts and local community leaders.

Interview participants and survey respondents were not randomly selected. Participants were selected by the Steering Committees in collaboration with their respective local officials. Therefore, while the perspectives captured and documented in this report may or may not be reflective of the individual

[49] The Coalition of Utility Cities (CUC) consists of eight Minnesota cities that host the state's largest power plants owned by investor-owned utilities. The CUC advocates to protect the interests of local residents and businesses by ensuring that local taxpayers don't bear a disproportionate share of the public infrastructure and safety costs of hosting power plants, and serves as a collective voice for these communities when large facilities are retired or converted to a new fuel source.

community or host communities as a whole, the stories included offer a sampling of what actively engaged community members are feeling, thinking, and doing with regard to the potential impact a power plant closure could have on the places they live, work, and play.

Interviews

The study authors conducted in-person, group interviews with each of the host communities included in this study. Interview participants for each host community were identified and selected by members of the Steering Committee. Interview participants included elected city and county officials, city and county staff, school district staff and superintendents, local business owners, representatives of local nonprofit and religious organizations, and community leaders.

Interview questions were designed to elicit conversation among interviewees about how a potential power plant retirement would affect the community, including effects on the local government tax base, including city, county, and school district budgets; businesses that interact with the power plant; and residents that live in the city or work at the plants. Interview questions used for local government officials and city, county, and school district staff can be found in **Appendix A-1.**[50]

The study authors conducted additional interviews to understand the perspectives of labor unions that represent power plant workers and learn about state support systems and programs that could be available to workers and communities. This input was gathered through interviews with representatives of the International Brotherhood of Electrical Workers, representatives of the Laborers' International Union of North America, representatives of the Boilermaker's Local #647, and a group interview with staff from the Minnesota Department of Employment and Economic Development.

All interviews were recorded to ensure accuracy of quotations. All quotes attributed in this report were approved by those who were attributed.

Community Surveys

To further capture the perspectives of the community, the study authors conducted an online survey questionnaire. The questionnaire was developed by the study authors in close collaboration with the Steering Committee. The questions included in the survey can be found in **Appendix A-2**.

The Steering Committee members shared the survey with roughly 10 community members each; survey participants were not the same individuals as those interviewed. Once participants responded and submitted their questionnaire, answers were coded for similar and different themes to supplement each community narrative.

[50] A similar, but modified, set of interview questions were used for community business and nonprofit leader interviews and for labor union representative interviews.

Appendix A-1: Interview Questions

Questions for Local Government Interviews

Questions refer to City, County, School Board, etc.

Project Introduction:

- CEE is partnering with the Coalition of Utility Cities, Xcel Energy, Minnesota Power, and community representatives to study the economic and social impact of the power plants in communities that host them.
    - Communities include:

Community	Power Plants	Fuel	Estimated Retirement * indicates approved retirement date
Becker, Sherburne, MN	Sherco 1, 2, 3	Coal	2023*, 2026*, 2030 (unit respective)
Oak Park Heights, Washington, MN	Allen S. King Plant	Coal	2028
Cohasset, Itasca, MN	Boswell 3, 4	Coal	2035, 2036 (unit respective)
Red Wing, Goodhue, MN	Prairie Island Nuclear Plant	Nuclear	2033, 2034 (unit respective)
Prairie Island Indian Community			
Monticello, Wright, MN	Monticello Nuclear Plant	Nuclear	2040

- Study includes economic modeling to assess the direct and indirect economic value of power plants to these communities and a qualitative analysis to assess the role the power plants play in people's lives and how key state stakeholders are thinking and planning for power plant closures.
- Goal of this study is to provide communities and state and local decision makers with information so that they can adequately plan and prepare for an eventual closure of the power plant.

Preliminary Questions

1. Do you know approximately how much the power plant contributes to your tax base?
    a. If yes
        i. City
        ii. County
        iii. School District

Interview Questions

2. In reference to question number one, please tell us what is funded through the taxes received from the power plant (utility)? (i.e. special projects, infrastructure, emergency services, etc.)

3. Do any of your local philanthropic efforts or charities benefit from the power plant? (E.g. a sports team sponsorship, community organizations)
    a. If so, please explain.

4. What is the community sentiment toward the plant / utility?
    a. What is it like today?
    b. Do you expect it to change going forward?
    c. How does that differ across local government entities?

5. What types of conversations are you having or hearing about the plant's future in your community?
    a. Are they positive or negative? Fearful/hopeful?

6. What are your main concerns regarding a potential power plant closure?
    a. Who will be directly impacted, that you know of?
    b. Who will be indirectly impacted, that you know of?

7. Do you anticipate any opportunities or benefits for your community from a power plant closure?
    a. If so, what?

8. What efforts have already been made around a transition? Are there any plans for what happens next in the community?
    a. Are there any stakeholder groups, advisory committees, or economic development efforts underway?
        i. If so, what do you think has been particularly successful or informative?
        ii. If an advisory committee or stakeholder group were to be formed, whom would you invite?

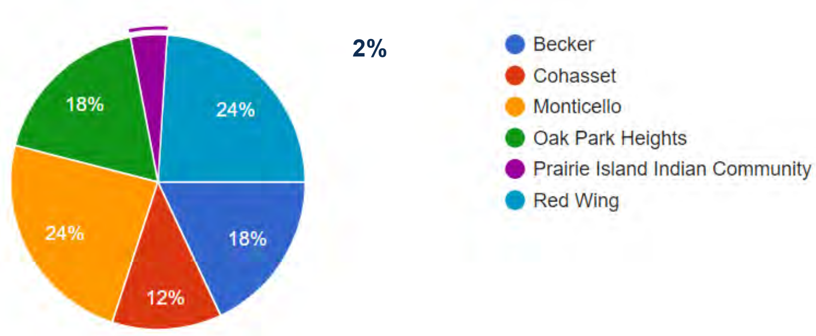
9. Does your city's comprehensive plan (or other planning document if applicable) address the future of your plant?
    a. If yes, how does it address the future of the plant?
    b. If no, do you have plans to address it in future planning documents?

10. What vision do you have for a successful transition for your community?

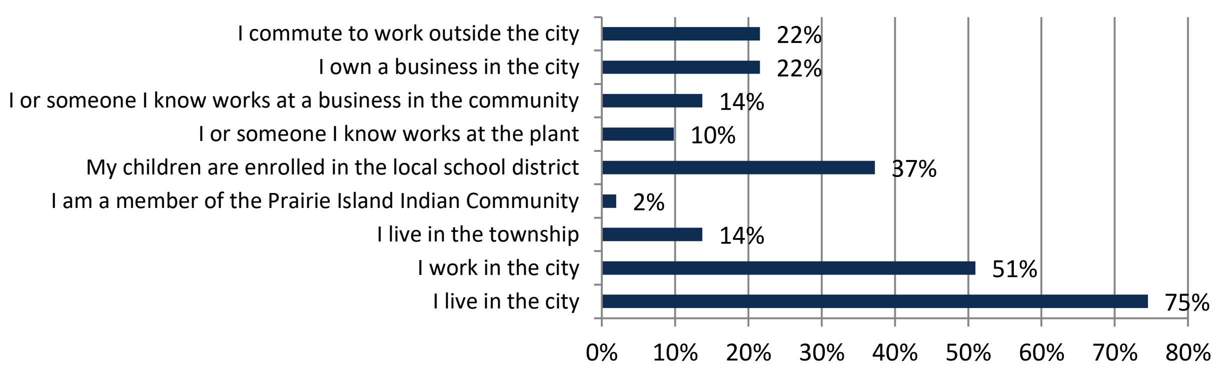
Appendix A-2: Online Community Survey

This survey was distributed by members of the Host Community Steering Committee, who were asked to distribute the study to up to 10 community members and business owners. In total, the survey received 51 responses. While the actual responses of the survey contain some unique identifiers, and thus are not shared for the sake of anonymity, the results below show high-level findings and response trends.

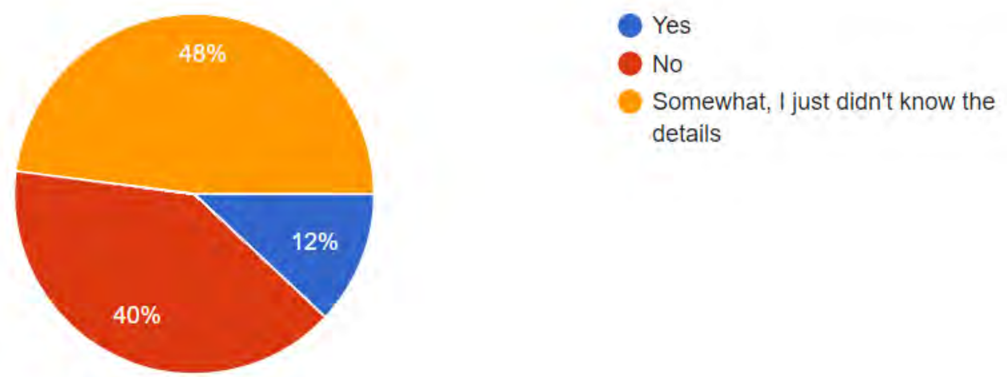
1. In which Minnesota community do you either live or work?



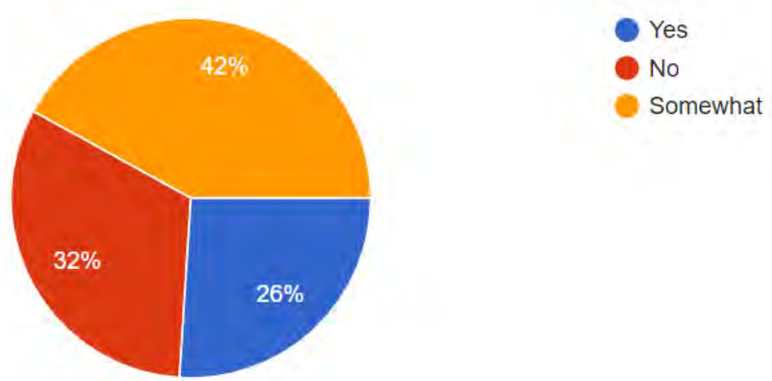
2. Please describe yourself. (Check all that apply)



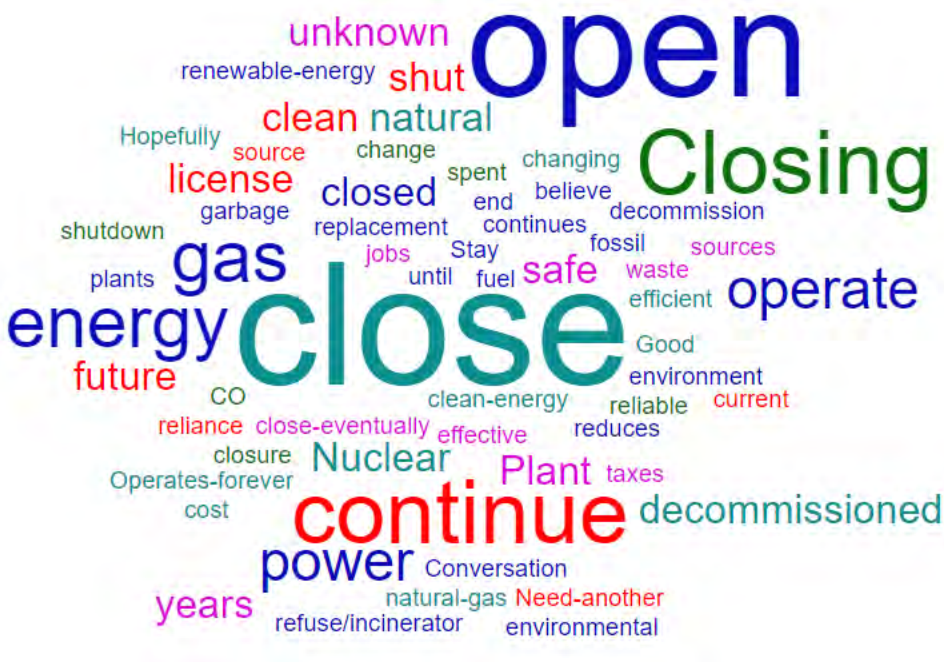
3. In Minnesota, utilities are required to regularly file their long-term plans for how they will cost-effectively meet customer energy needs called an Integrated Resource Plan (IRP). The Minnesota Public Utilities Commission reviews each Resource Plan and often makes changes before approving the utility's plan. Are you familiar with the utility resource planning process?



4. The Minnesota Public Utilities Commission is made up of five appointed commissioners that regulate Minnesota's utilities to ensure safe, reliable, and affordable energy. Are you familiar with the role of the Minnesota Public Utilities Commission?

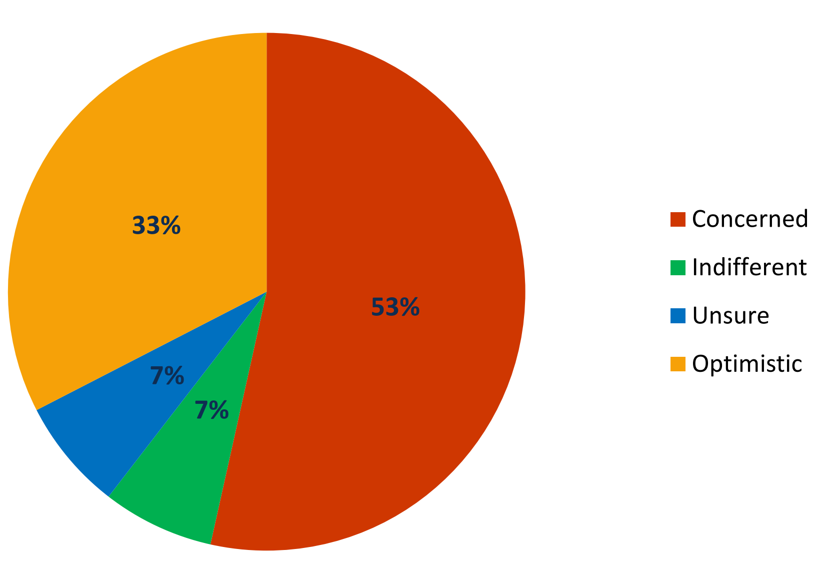


5. What do you think is the likely future of the power plant in your community?



6. When do you think this future will happen?

7. How do you feel about this future?



8. What are some of your favorite things about your community?

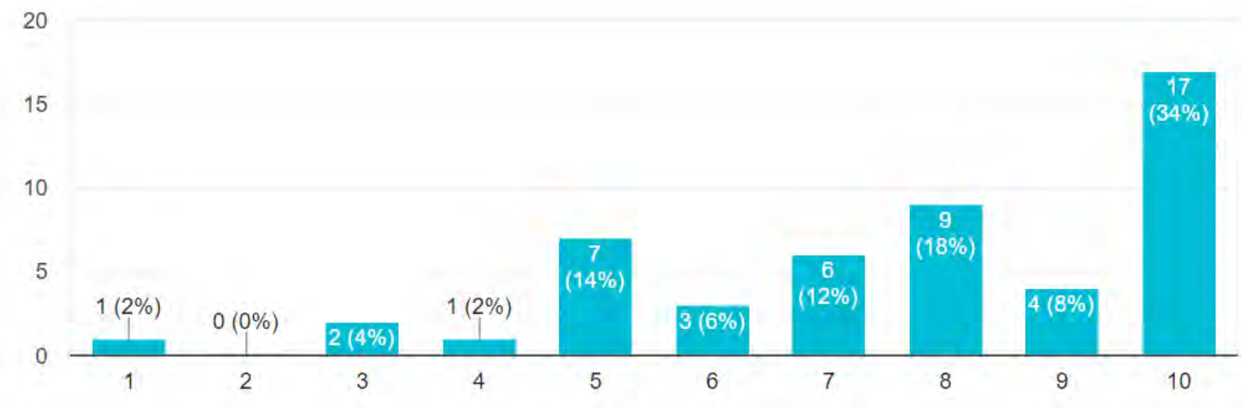
9. What is unique about your community?

10. Ten years from now, what vision do you have for your community? Consider the local economy, your family, your neighborhood, etc.

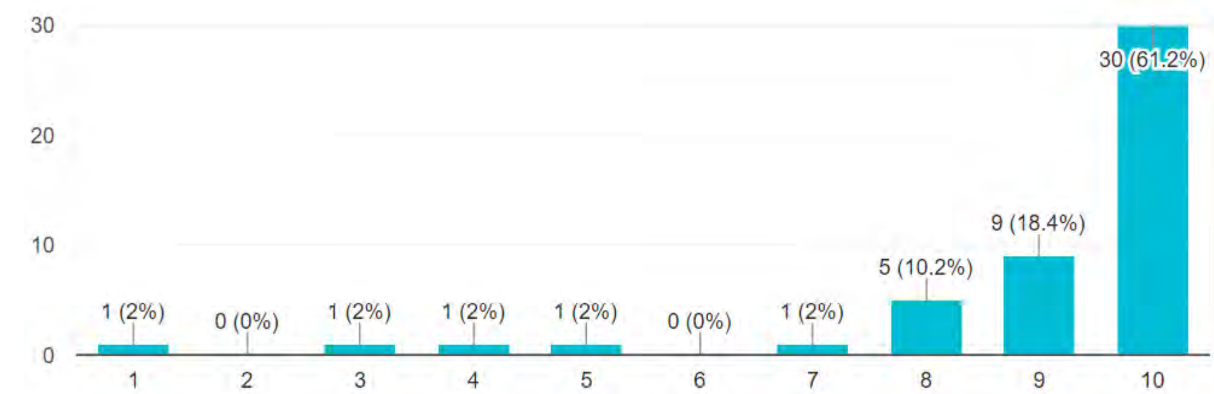
11. What are some of the greatest needs in your community?

12. What does the power plant mean to your community?

13. Rank how important the power plant is to your community's identity. (10 being very important)



14. Rank how important is the power plant to your community's economy. (10 being very important)



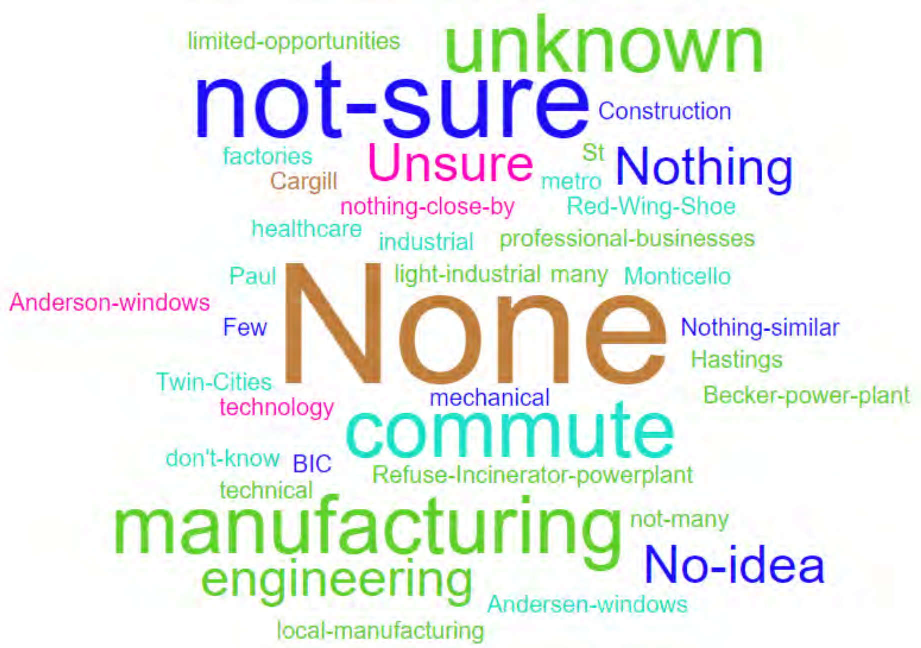
15. What benefits, if any, does the power plant provide to your community?

16. What negatives, if any, does the power plant provide to your community?

17. What new or positive opportunities would occur in your community if the power plant were to close at some point in the future?

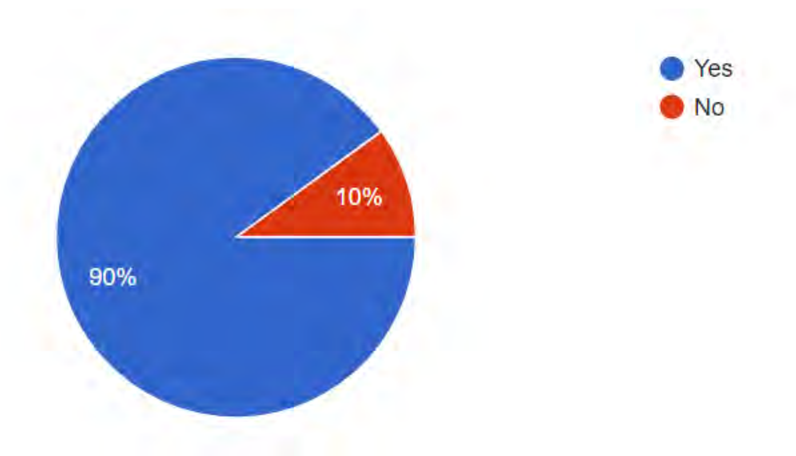
18. What concerns would you have if the power plant were to close at some point in the future?

19. What other jobs are available nearby for the plant workers?



20. What industries, beyond the power plant, have the most promise in your community?

21. (A) Do you think the schools and local charities would be affected if the plant were to close at some point in time?



21. (B) If yes, how so?

"There will be financial impacts for both. The school district gets most funding from the state and federal governments, but referendums will be impacted, which impacts what services and other items our school will be able to provide in the future. Local charities will also see a decline in revenue from the closure of the power plant."

"Any time you remove taxes from the community it puts more of a burden on other payers."

"Loss of any current financial contribution coming to them - would have to fight for other resources that may come from the city or other individuals (with the loss of the tax base from the power plant - funding other programs will have to come from somewhere)"

"Well paid, educated workers would relocate out of the community; schools would be negatively affected by the loss of taxes, potential loss of students, loss of community partner"

APPENDIX B: KEY STATE FINANCIAL POLICIES

Minnesota state policies regarding how state and regional tax revenue is distributed among local governments are important considerations in community, regional, and state planning for power plant retirements in Minnesota. Minnesota's host communities contribute significant revenue to these policies and programs and currently receive little in return. Power plant retirements will affect these policies and programs in terms of the total revenue amounts generated and the breakdown of which jurisdictions contribute and which receive funds. The following section provides an overview of some of those relevant state policies.

Local Government Aid

Minnesota's cities and counties receive funding from a number of sources. One important source of funding for many cities and counties is state aid. In Minnesota, the largest portion of state aid to cities and counties comes from the Local Government Aid (LGA) program. LGA is a general purpose aid that Minnesota cities and may receive from state tax dollars. The LGA program is intended to reduce disparities in education and local services between jurisdictions with relatively high tax values and those with relatively low tax values. The idea underlying this program is that no matter where a person happens to live in Minnesota, the quality of services should remain fairly consistent.[51]

Cities may use LGA funds on any lawful expenditure such as infrastructure, public safety, or economic development.[52] LGA is distributed annually to cities based on need, which is determined through a formula. The formula considers a city's revenue needs (calculated using variables that are correlated to city spending) and its tax base from two years prior. For example, LGA funding levels for 2020 are based on cities' 2018 tax data. Further, a key determinant in LGA funding awards is the amount that a jurisdiction received in the prior year.

Host Communities and LGA

Most of the cities included in this study do not receive LGA funding because of the significant tax base they receive from the power plants they host. The table below shows the 2020 estimated LGA funding for each of the cities included in this study, assuming no changes to the LGA program or tax base for each of the cities.

Table 8. Host Community 2020 LGA Overview

City	Total Need	Tax Base	Unmet Need	2020 LGA
Red Wing	$11,800,000	$14,400,000	$0	$800,000
Cohasset	$1,800,000	$4,900,000	$0	$0
Becker	$2,600,000	$7,800,000	$0	$0
Oak Park Heights	$2,900,000	$4,300,000	$0	$0
Monticello	$7,400,000	$13,100,000	$0	$0
**Tax Base determined by multiplying a city's adjusted net tax capacity (ANTC) by the statewide average city property tax rate (43.5561% in 2020) — rounded to nearest hundred thousand.*				

[51] "The basics of local government aid in Minnesota." MPR News. September 9, 2010. https://www.mprnews.org/story/2010/09/09/ground-level-city-budget-101
[52] "Local Government Aid (LGA) Certification for Cities." Minnesota Department of Revenue. Accessed November 5, 2019. https://www.revenue.state.mn.us/local-government-aid-lga-certification-cities

Losing the local tax base associated with the power plants included in this study would leave several host communities with an unmet revenue need, making those communities eligible for LGA funding. The following table estimates the unmet revenue need for each of the cities included in this study if the power plant within those communities were to retire and provide no property taxes to the cities.

Table 9. Host Community 2020 LGA Overview Assuming Plant Closures

City	Total Need	Tax Base	Unmet Need
Red Wing	$11,800,000	$6,200,000	$5,600,000
Cohasset	$1,800,000	$2,400,000	$0
Becker	$2,600,000	$2,000,000	$600,000
Oak Park Heights	$2,900,000	$3,200,000	$0
Monticello	$7,400,000	$5,500,000	$1,900,000
**Tax base determined by multiplying a city's adjusted net tax capacity (ANTC) by the statewide average city property tax rate (43.5561% in 2020) — rounded to nearest hundred thousand.*			

As noted above, a city's unmet need would not be addressed by the LGA program for two years after the unmet need occurs and LGA funding for cities included in this study may be lessened because the cities have either received no LGA funds or very little LGA funding in prior years.

Fiscal Disparities Program

Minnesota has two programs to share the tax base from commercial and industrial development in the state. These programs are called the Metropolitan Fiscal Disparities Program and the Taconite Fiscal Disparities Program. The Metropolitan Fiscal Disparities Program covers the Twin Cities' seven-county metropolitan area, while the Iron Range Fiscal Disparities Program covers communities in the Taconite Relief Area. The programs were created to improve equity across regions of the state by reducing disparities in property tax wealth and to discourage inter-regional competition between communities for businesses and tax base. Both programs distribute a portion of commercial, industrial, and utility tax base growth, over a base level, to the communities within the respective regions. Both programs distribute 40% of the growth in commercial, industrial, and utility tax base to their respective regions.

For a host cities located within either of the two fiscal disparity regions, the fiscal disparity programs would help offset a portion of any lost tax base resulting from a power plant closure. Such power plant closures would, however, reduce the overall revenue generated through the fiscal disparity program for all jurisdictions in that region.

Among the host communities included in this study, Oak Park Heights is within the Metropolitan Fiscal Disparities Program and Cohasset is within the Iron Range Fiscal Disparities Program. No other host communities are part of a fiscal disparities program. The Allen S. King plant in Oak Park Heights and the Boswell Energy Center in Cohasset contribute significant amounts of tax capacity to the area-wide pools for the respective fiscal disparities programs.

Iron Range Resources and Rehabilitation

The Department of Iron Range Resources and Rehabilitation (IRRR) is a Minnesota state agency with a mission to promote and invest in business, community, and workforce development for the betterment of northeastern Minnesota.[53] The Department of IRRR was established in 1941 and serves the 53 cities, 134 townships, and 15 school districts located within the Taconite Relief Area.[54],[55] The agency is jointly led by a commissioner appointed by the governor and a nine-member board, the Iron Range Resources and Rehabilitation Board. The IRRR is funded primarily through taconite production taxes paid by mining companies in lieu of property taxes.

The Department of IRRR provides grants and loans to businesses, local units of government, educational institutions, and nonprofits. IRRR funding for local governments may be used for commercial and residential redevelopment, infrastructure projects, and downtown investments.

Cohasset, Minnesota, is located within the Taconite Relief Area territory and therefore is currently eligible to apply for funding from the IRRR's community programs. Additionally, businesses currently in Cohasset or looking to relocate to Cohasset may be eligible for assistance from one of IRRR's various business development programs. Cohasset is the only community included in this study that is located within the Taconite Relief Area.

Wind and Solar Energy Production Taxes

In Minnesota, owners of wind and solar energy installations pay a production tax rather than traditional property taxes. The production tax is structured differently for wind and solar resources. The tax on wind energy is a progressive rate that increases with the size of the wind energy system. Any Minnesota-sited solar energy system with a capacity of one megawatt or more is taxed at $1.20 per megawatt-hour. Solar energy systems with a capacity below one megawatt are exempt from the solar energy production tax.

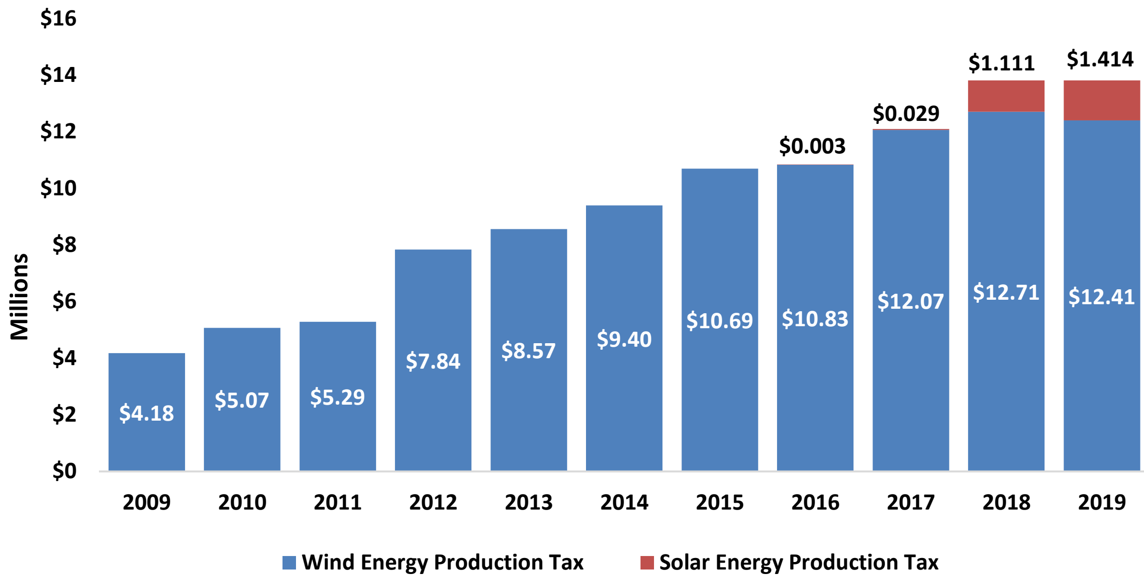
The total revenue from both solar and wind energy taxes go to local governments; 80% of the total production tax revenue is distributed to the county in which the system is located and 20% is distributed to the city or township in which the installation is located.

[53] "About us." Minnesota Department of Iron Range Resources and Rehabilitation. Accessed November 5, 2019. https://mn.gov/irrrb/about-us/

[54] Taconite Assistance Area map. Minnesota Department of Revenue. Accessed November 5, 2019. https://www.revenue.state.mn.us/sites/default/files/2019-01/Map_Taconite_Assistance_Area%20pdf.pdf

[55] Minnesota Statute 273.1341

Figure 2. Total wind and solar energy production tax revenues



Source: Minnesota Department of Revenue

Though revenue from the wind and solar energy production taxes has risen quickly over the past decade, wind and solar production tax revenue remains far below property tax revenue paid by Minnesota's utilities.

APPENDIX C: MINNESOTA'S EXISTING ECONOMIC DEVELOPMENT AND WORKFORCE PROGRAMS

The Minnesota Department of Employment and Economic Development assists with state and local economic development efforts, workforce training and recruitment, and provides assistance to workers after layoffs or business closures. The study authors conducted interviews with representatives of DEED to better understand the workforce and economic development services and support that are currently available in Minnesota. These services and support may be helpful for workers and communities facing power plant retirements in Minnesota.

Minnesota Department of Employment and Economic Development (DEED)

DEED is the state's principal economic development agency. DEED programs aim to promote business recruitment, expansion, and retention; international trade; workforce development; and community development.[56] DEED's community, business, and workforce assistance programs may be helpful for communities in Minnesota facing power plant retirements and subsequent transitions.

DEED has experience supporting large employers and dislocated workers during large layoffs, including ones associated with a retiring power plant. DEED is also aware that several power plants across Minnesota have proposed or approved closure dates. However, DEED does not currently a formal response plan for each of the respective host communities.

Through a group interview for this study, DEED's Workforce Strategy Consultants and Rapid Response Team shared existing services and best practices for Minnesota communities facing economic transitions as a result of retiring power plants.

Existing DEED Services

The following programs and services offered by DEED are listed in order of nearest to longest term strategies that utility employers and host communities could pursue to assist with the transition associated with a power plant closure.

Regional Workforce Strategy Consultants

In preparation for power plant closures, DEED's Workforce Strategy Consultants may be a starting point for accessing DEED support. Workforce Strategy Consultants are assigned to six different areas in Minnesota to help align resources, facilitate regional collaboration, and leverage DEED's workforce and economic services to drive economic opportunity.[57] With their regional and strategic focus, Workforce Strategy Consultants can serve as a central point of contact for communities to navigate assistance options and coordinate key stakeholders at the state and local level. For host communities,

[56] "About." Minnesota Department of Employment and Economic Development. Accessed August 6, 2019. https://mn.gov/deed/about/

[57] "Workforce Strategy Consultants." Minnesota Department of Employment and Economic Development. Accessed August 6, 2019. https://mn.gov/deed/business/help/workforce-assistance/wf-strategy.jsp

this could potentially include coordination with DEED's Business Development Specialists and Labor Market Analysists to develop a data-driven, regional labor market plan for their community to attract new businesses and workforce talent in high-growth areas as well as secure federal and state Economic Development Assistance funding opportunities. Workforce Strategy Consultants could also work with Xcel Energy and Minnesota Power to encourage the utilities to transition existing plant workers into decommissioning work after the plant retires and ensure that workers are aware of local CareerForce locations to access career development services.

While DEED offers a wide portfolio of services to communities, employees and jobseekers, and businesses, navigating those services can be confusing. For these reasons, early engagement by the community with Workforce Strategy Consultants could lead to a better understanding of available support for communities and workers impacted by plant closures.

Dislocated Worker Program and Rapid Response Team

In the event of a large (over 50 employees) or small (under 50 employees) layoff or business closure, the State Rapid Response Team (SRRT) provides employers and employees with support to move forward. The program provides resources for laid off employees — including helping them find and prepare for a suitable new job — as well as helping the employer notify employees of their layoff in an orderly, legal manner. Federal law requires employers to notify DEED at least 60 days prior to a large layoff or facility closure.[58]

Proactive engagement with the SRRT may provide Xcel Energy and Minnesota Power time to strategize and leverage services intentionally to help plant workers experience a smoother, quicker transition into suitable employment. Key information to communicate with DEED includes the timeframe, size, and job types that will be laid off. The utilities and host community city staff may also collectively approach their Regional Workforce Strategy Consultant, described above.

Up to six months prior to a plant closure, the SRRT will implement the services offered through the Dislocated Worker Program, by connecting the workers with a Dislocated Worker Service Provider.[59] The SRRT is the first responder when businesses close down or prepare for a layoff. The SRRT supports employers and affected workers in several ways. First, the SRRT conducts an on-site meeting with the employer and union leaders (if applicable) to understand the timeframe, size, and job types of employees that will be laid off. Shortly after, DEED's SRRT and Unemployment Insurance representatives meet with employees to share an overview of available state resources including the Dislocated Worker and Unemployment Insurance programs. The Dislocated Worker services include:

- Career Planning and Counseling, in which a Dislocated Worker Counselor assesses the talents and interests of employees to come up with a personalized job or career plan for each individual.

[58] "Considering Layoff." Minnesota Department of Employment and Economic Development. Accessed August 19, 2019. https://mn.gov/deed/business/starting-business/management-basics/considering-layoff.jsp
[59] "Service Providers for the Dislocated Worker Program." Minnesota Department of Employment and Economic Development. Accessed August 19, 2019. https://mn.gov/deed/job-seekers/recently-unemployed/layoff/dwp-service-providers.jsp

- Job Search Assistance, including help with resumes, cover letters, and LinkedIn profiles as well as practice interviewing.
- Counselor Approved Training/Retraining, as the Dislocated Worker Counselor deems necessary. For example, funds are available for short or long-term training to obtain a General Education Diploma or acquire new workplace skills.
- Need-Based Support, as eligible, to cover the costs of new uniforms, tools and books, transportation to job sites, and childcare. Dislocated workers often also receive unemployment insurance.

In all cases, the SRRT tries to transition workers to jobs that pay close to their original wages and benefits, in fields that interest them. The team also offers additional support for veterans and jobseekers facing language, disability, or educational barriers to re-employment.

DEED also assists with the recruitment and facilitation of a Planning and Selection Committee to oversee Dislocated Worker Service Provider process in the case of large layoffs. This committee is made up of company management, employees, and union leaders to identify site-specific worker needs.

Other Services

An important consideration for communities is the indirect impact the power plant retirement could have on their economy. When a large employer leaves a community or closes, the economic impact often affects more than just those who work at the plant. Some small businesses and restaurants that rely on customers that work in the plant can struggle if customers lose their employment or leave. DEED can similarly assist these smaller employers during layoffs, as described in the section above, by helping direct those laid off to eligible support.

If others in the community find themselves seeking a new job, DEED offers "universal services" that any resident of Minnesota could be eligible for. These include the following:

- No-fee online job database
- Veterans assistance
- Labor market analysis
- Apprenticeship programs
- Job search assistance
- Referrals to food, health, and childcare support

As communities consider their future after the power plant, land use and environmental pollution at the plant site may become central issues. Communities can apply for DEED's Cleanup Revolving Loan Program and Minnesota Pollution Control Agency grants to conduct full environmental remediation at former plant sites to expand their options for economic redevelopment.[60]

[60] "Cleanup Revolving Loan Program." Minnesota Department of Employment and Economic Development. Accessed August 19, 2019. https://mn.gov/deed/government/financial-assistance/cleanup/cleanuprevolvingloanprogram.jsp
"Doing It Right II: Job creation through Colstrip cleanup." Northern Plains Resource Council. April 2019. https://northernplains.org/wp-content/uploads/2019/04/DIRTII_FINAL_WEB.pdf

Finally, DEED staff recommended host communities also form Community Redevelopment Advisory Committees. These committees can be comprised of strategic, well-connected community members to advise the community planning process and implementation as well as to help recruit new economic opportunities to the community.

DEED Service Takeaways

1. DEED has services that may be helpful for plant workers and other workers affected by a power plant closure.
2. Utilities and host communities should communicate as early as possible with DEED to collaborate on a transition plan in advance of a closure.
3. Workforce Strategy Consultants are an entry point for DEED assistance for communities facing power plant closures.
4. DEED's Rapid Response Team cannot get involved until six months away from plant layoffs, but other strategies can be pursued in advance.
5. DEED's Business and Community Development staff can work together with city planning departments to supply regional labor market trends and opportunities as well as leverage larger networks and EDA funds.
6. Host communities can form Community Redevelopment Advisory Committees to advise the community planning process and implementation as well as to help recruit new economic opportunities to the community.
7. Communities can apply for DEED's Cleanup Revolving Loan Program and Minnesota Pollution Control Agency grants to conduct environmental remediation at former plant sites to expand options for economic redevelopment.

APPENDIX D: LITERATURE REVIEW OF TRANSITIONING POWER PLANT COMMUNITIES

This appendix contains a copy of a standalone report compiled by the authors (Audrey Partridge and Brady Steigauf of Center for Energy and Environment) in January 2020.

National Case Studies of Communities in Transition: After the Power Plant

The authors of this study selected four case studies of communities around the country that have experienced a community transition as a result of a power plant closure. Each community has a unique story and all are at varying stages of their transition. Below the authors provide a brief overview of each community's transition story along with key takeaways that may be informative for Minnesota's host communities, and other host communities, as they anticipate and plan for eventual power plant closures.

Case Studies from Around the Country

Diablo Canyon Power Plant, California

Table 10: Diablo Canyon Nuclear Plant Quick Facts

Power Plant Information	
Fuel type	Nuclear
Closure date	2025
Generation capacity	2,200 megawatts (10% of California's capacity)
Plant employees	1,500
Plant site (acres)	1,000
Community Information	
Avila Beach & San Luis Obispo population	~ 62,000
San Luis Obispo County population	280,000
Estimated economic contribution to local community	$1 billion

Diablo Canyon Power Plant is a two-unit, nuclear power plant located in Avila Beach, California, just a few miles from San Luis Obispo, California. Avila Beach and San Luis Obispo have a combined population of about 62,000 residents — the surrounding county, San Luis Obispo County, has a population of about 280,000 residents. Diablo Canyon Power Plant sits on the Pacific coast and has been in operation since 1985. The Diablo Canyon Power Plant produces roughly 10% of California's electricity and is the largest private employer in San Luis Obispo County with an estimated $1 billion impact on the local economy.[61]

[61] Leslie, Kaytlyn. September 19, 2018. "Governor signs bills to give SLO County $85 million Diablo Canyon settlement." *The Tribune*. https://www.sanluisobispo.com/news/local/article218698490.html

In late 2016, after seven years of negotiation, California utility Pacific Gas and Electric (PG&E), International Brotherhood of Electrical Workers Local 1245, local communities, and environmentalist organizations reached an ambitious transition plan settlement agreement for the closure of Diablo Canyon, California's last operating nuclear plant. Though this plant closure and the associated transition plan is not yet complete, the components of the settlement agreement and the process stakeholders used to achieve the settlement terms may be informative for Minnesota's community transition efforts. Below is an overview of the settlement agreement and process as well as additional transition efforts by the local affected communities.

The settlement agreed upon by parties[62] was to close the Diablo Canyon nuclear plant at the end of its license, in 2025, replace the electricity provided by the plant with other carbon-free resources, and create a smooth transition for workers and local communities.

Transition Package for Workers and Communities

For workers, the agreement created a 25% retention bonus for workers who remain employed and working at the plant until closure. For workers who wished to continue working after the plant closed, the plan provided an opportunity to remain in the community and expand their skills through a program to transition plant workers from operational plant jobs to the ongoing work of decommissioning the plant. This retraining program is aimed at enabling PG&E to use its existing workforce in the decommissioning process as opposed to contracting that work to outside companies.[63,64] The agreement called for $350 million in funding from PG&E for the worker retention and retraining program.

In addition to the transition plan for workers, the deal also included assistance for the local community.[65] The total settlement package paid for by PG&E totals between $122.5 million and $147.5 million,[66] including:

- $85 million in aid to seven nearby cities, the San Luis Unified School District, and San Luis Obispo County to help offset the economic impacts of the plant closure.[67]

[62] The full list of parties to the Diablo Canyon settlement agreement include Pacific Gas and Electric, International Brotherhood of Electrical Workers Local 1245, Coalition of California Utility Employees, Friends of the Earth, Natural Resources Defense Council, Environment California, California Energy Efficiency Industry Council, Alliance for Nuclear Responsibility, the County of San Luis Obispo, the Coalition of Cities (Arroyo Grande, Atascadero, Morro Bay, Paso Robles, Pismo Beach and San Luis Obispo) and the San Luis Coastal Unified School District.
[63] Dalzell, Tom. November 30, 2018. "Diablo Canyon: A Just Transition for Workers and the Environment." UC Berkeley Labor Center. http://laborcenter.berkeley.edu/diablo-canyon-just-transition-workers-environment/
[64] News Release: June 21, 2016. "In Step with California's Evolving Energy Policy, PG&E, Labor and Environmental Groups Announce Proposal to Increase Energy Efficiency, Renewables and Storage While Phasing Out Nuclear Power Over the Next Decade." Pacific Gas & Electric Company. https://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160621_in_step_with_californias_evolving_energy_policy_pge_labor_and_environmental_groups_announce_proposal_to_increase_energy_efficiency_renewables_and_storage_while_phasing_out_nuclear_power_over_the_next_decade
[65] Dalzell, Tom. November 30, 2018. "Diablo Canyon: A Just Transition for Workers and the Environment." UC Berkeley Labor Center. http://laborcenter.berkeley.edu/diablo-canyon-just-transition-workers-environment/
[66] Leslie, Kaytlyn. November 28, 2016. "PG&E to pay $85 million to cities, SLO County, school district for Diablo Canyon Closure." *The Tribune*. https://www.sanluisobispo.com/news/local/article117604388.html
[67] Leslie, Kaytlyn. November 28, 2016. "PG&E to pay $85 million." See note 67.

  - Of that, $75 million is expected to go to offset property tax losses by the school district, the county, and 69 other special districts, and
  - $10 million will go for economic development efforts in the county and cities.
- Between $37.5 million and $62.5 million toward local emergency planning efforts until all spent fuel is in dry cask storage and the two nuclear reactors are fully decommissioned.[68]

The Process for Approving the Settlement

Despite support from the broad coalition of parties to the settlement, the full settlement agreement was not approved by the California Public Utilities Commission. In January 2018, the Commission denied portions of the settlement package due to its cost and its expected impact on electric rates.

Supporters of, and parties to, the settlement turned to the California legislature after the CPUC decision to reject portions of the agreement.[69] The state legislature introduced California Senate Bill 1090, which was reflective of the original settlement agreement between parties and PG&E. The bill, which received bipartisan support, was signed into law on September 19, 2018, directing the California Public Utilities Commission to approve the $85 million Diablo Canyon settlement agreement and PG&E's full $350 million proposed employee retention and retraining program.[70]

Transition Efforts to Date

The funding from the new law is just beginning to be allocated. In late April 2019 San Luis Obispo County, the county most directly affected by the plant closure, approved a $300,000 grant to fund an employment development project and create an employment action plan to ease the plant closure's impact on the community.[71] The project will act regionally and develop an employment plan across two counties and 12 cities, seeking to unify regional efforts to support economic vitality and job creation and retention.[72]

Additionally, as the community looks toward transition, they are receiving advice from other cities through the Alliance for Nuclear Responsibility. The Alliance is a federal roundtable for sharing lessons learned and resources for tax and job loss in communities going through nuclear plant closure transitions.[73] Communities that had undergone similar transitions emphasized the importance of engaging the plant, the public, and policymakers early to strategize on an economic mitigation plan.

[68] Leslie, Kaytlyn. January 11, 2018. "Diablo Canyon will close in 2025 — without SLO County's $85 million settlement." *The Tribune*. https://www.sanluisobispo.com/news/local/article194189949.html
[69] Press Release: September 20, 2018. "California Gov. Brown Signs Historic Diablo Canyon Nuclear Plant Bill." *Power Magazine*. https://www.powermag.com/press-releases/california-gov-brown-signs-historic-diablo-canyon-nuclear-plant-bill/
[70] Leslie, Kaytlyn. September 19, 2018. "Governor signs bill." See note 62.
[71] April 24, 2019. "SLO County supervisors approve grant funding for job creation project." *KSBY 6 News*. https://ksby.com/news/local-news/2019/04/24/slo-county-supervisors-approve-grant-funding-for-job-creation-project
[72] Johnson, Peter. April 25, 2019. "Mapping the future: County pours $300,000 into private sector led Hourglass Project." *New Times*. https://www.newtimesslo.com/sanluisobispo/mapping-the-future-county-pours-300000-into-private-sector-led-hourglass-project/Content?oid=8302489
[73] Becker, Rochelle. April 25, 2019. "Losing Diablo will be tough on SLO's economy. Feds are looking at ways to help." *The Tribune.* https://www.sanluisobispo.com/opinion/readers-opinion/article229700029.html

Maine Yankee Nuclear Plant, Maine

Table 11: Maine Yankee Plant Quick Facts

Power Plant Information	
Fuel type	Nuclear
Closure date	1997
Generation capacity	840 megawatts
Employees	600[74]
Plant site (acres)	820
Community Information	
Wiscasset population	3,600
Lincoln County population	34,000
Estimated economic tax contribution to city	$13 million

The Maine Yankee nuclear power plant was one of the nation's first nuclear power plants, and began producing electricity for Maine and other parts of New England in 1972. The Main Yankee plant contained a single-unit pressurized water reactor with about 840-megawatts of capacity.[75] The Maine Yankee plant was located along the Back River in the historic village of Wiscasset, Maine, which has a population of about 3,600 residents.[76] Wiscasset is also home to a number of historic sites and a large part of the village is a part of the National Register of Historic Places.[77] In addition to the Maine Yankee plant, Wiscasset is a tourist destination and has one of the State's most vibrant working waterfronts, with summertime activities of lobster fishing, sport fishing, and clam and worm digging.[78]

From 1972 to 1996, the Maine Yankee plant, generated 119 billion kilowatt-hours of electricity[79] and was Maine's largest power plant. The Maine Yankee plant was a significant revenue source for Wiscasset. Maine Yankee permanently closed the plant in August 1997 because the plant was no longer economically viable to operate.[80] The plant closure was abrupt and occurred eleven years earlier than expected.[81]

An Economic Downturn

Wiscasset flourished during the years that the Maine Yankee plant was in operation. In 1996, just before the plant closed, Maine Yankee paid $13 million in property taxes, more than 90% of it the city's

74 Barlow, Daniel. September 1, 2013. "Maine Yankee: A case study on decommissioning." *Rutland Herald*. https://www.rutlandherald.com/opinion/perspective/maine-yankee-a-case-study-on-decommissioning/article_fb00391e-1b09-56ff-bdaa-7902ccbce843.html
75 Riddle, Lyn. November 2, 1987. "Maine Voters to Decide Fate of Nuclear Plant." *New York Times*. https://www.nytimes.com/1987/11/02/us/maine-voters-to-decide-fate-of-nuclear-plant.html
76 Estimated by the U.S. Census Bureau in 2017.
77 "Historic and Prehistoric Overview." Town of Wiscasset. Accessed August 20, 2019. https://www.wiscasset.org/visit/historic-and-prehistoric-overview
78 "Visit Wiscasset." Town of Wiscasset. Accessed August 20, 2019. https://www.wiscasset.org/visit
79 Brogan, Beth. December 17. 2016. "Maine Yankee fallout: A town's turmoil, 20 years in the making." *Bangor Daily News*. https://bangordailynews.com/2016/12/17/news/midcoast/maine-yankee-fallout-a-towns-turmoil-20-years-in-the-making/
80 Maine Yankee. Accessed August 20, 2019. http://www.maineyankee.com
81 February 2005. "A Model for Public Participation in Nuclear Projects." The Maine Yankee Decommissioning Advisory Panel. http://www.maineyankee.com/public/cap%20final.pdf

tax base.[82] Once the plant closed, Wiscasset faced a dramatically different financial reality. In 2005, as decommissioning of the plant came to a finish, the total tax revenue from Maine Yankee was $1 million and in 2018 it was around $700,000, according to town figures. As a result, taxes were raised for residents and local businesses, municipal jobs went unfilled, and the village started charging for sewer service.[83] By 2013, Wiscasset ranked as the fourth-poorest community in Maine, the Boston Globe reported at the time, and property taxes had increased more than tenfold.[84]

After the plant closed, falling enrollment led the town to close its primary school and reshuffle all students into the former middle and high schools. According to the Bangor Daily News, the impact on Wiscasset's sense of community was abrupt and evident. School athletic teams dwindled to the point that the middle school had no baseball team for two years, the Wiscasset Newspaper reported.[85]

The transition from being a town with abundant resources to one with a limited budget created tensions for local governance and local residents. Wiscasset, however, was helped by long-term investment ahead of the shutdown that left some $12 million in reserve, money used years later to mitigate property tax increases.[86]

However, many community members have hope that the community will bounce back, as tourism grows and the local historic society protects the town's valuable historical assets.[87]

Decommissioning

Maine Yankee nuclear plant was one of the first large commercial nuclear reactors to complete decommissioning.[88] Decommissioning took from 1996 to 2005, which is considered very quick for a nuclear plant of its size. The decommissioning of the plant was largely hailed a success. In fact, the Maine Yankee company was the recipient of the 2005 New England Business Council's Outstanding Environmental Innovation Award in recognition of the approaches and technologies used during the decommissioning and environmental restoration of the Maine Yankee nuclear power plant.[89] This success was in spite of the fact that Maine Yankee was forced to take on the job of removing fuel from the reactor and dismantling buildings itself after the contractor it hired could not finish the $250 million job.[90]

One important step that Maine Yankee undertook for decommissioning is that the company created the Maine Yankee Community Decommissioning Advisory Panel, a vehicle for communication with the public. The panel of community stakeholders became the resident experts on issues related to the looming questions about the future of the 800+ acre site and the inventory of 1,434 spent nuclear fuel

[82] Brogan, Beth. December 17, 2016. "Maine Yankee Fallout." See note 80.
[83] Zambito, Thomas C. June 19, 2019. "Decades later, Maine Yankee plant stuck with spent nuclear fuel as feds pick up $10M tab." *The Journal News*. https://www.lohud.com/story/news/investigations/2019/06/19/maine-yankee-nuclear-plant-stuck-spent-fuel/1345799001/
[84] Brogan, Beth. December 17, 2016. "Maine Yankee Fallout." See note 80.
[85] Brogan, Beth. December 17, 2016. "Maine Yankee Fallout." See note 80.
[86] Zambito, Thomas C. June 19, 2019. "Decades later." See note 84.
[87] Brogan, Beth. December 17, 2016. "Maine Yankee Fallout." See note 80.
[88] Maine Yankee. Accessed August 20, 2019. http://www.maineyankee.com
[89] Maine Yankee. Accessed August 20, 2019. http://www.maineyankee.com
[90] Zambito, Thomas C. June 19, 2019. "Decades later." See note 84.

assemblies.[91] The panel held its first meeting just two weeks after the plant closure was announced; all panel meetings were publicly noticed and open to all.[92] In total the panel hosted 50 public meetings to educate the public about issues related to decommissioning. They also enabled stakeholders to urge the company to comply with clean-up standards that were more stringent than what the law required — the company agreed and met those more rigorous requirements. Additionally, the company was open to public input and included considerations of public perception in its project review process.[93]

Spent Fuel Storage

The Maine Yankee plant site is still home to spent nuclear fuel. Twenty-three years after the plant closed, an 11-acre site on Bailey Point Peninsula continues to host 60 cement and steel canisters loaded with decades' worth of spent nuclear fuel, each weighing 150 tons.[94]

Maine Yankee sued the U.S. Department of Energy to recover ratepayer funds to be directed toward spent fuel storage. The owners of Maine Yankee and two other Yankee plants decommissioned in Connecticut and Massachusetts won around $472 million from the federal government for failing to create an underground repository for the nation's nuclear waste, as it had promised.[95] Nonetheless, in recent years there has been little to no progress toward the development of a federal repository for nuclear fuel.

After decommissioning was complete, the advisory panel shifted to become the Maine Yankee Community Advisory Panel on Spent Nuclear Fuel. The new advisory panel works toward open communication, public involvement, and education on the interim storage of spent nuclear fuel at the Maine Yankee site, and advocating for removal to a safe location outside of New England.[96] Today, the panel meets just once a year and its primary business is drafting a letter to federal lawmakers urging them to back legislation to aid towns saddled with nuclear waste.[97]

Efforts to redevelop the 800-acre site on which it stood have not advanced—and many community members believe that redevelopment opportunities for the Maine Yankee site are limited until the spent fuel is gone.[98] "The surrounding communities are stuck with a spent fuel installation, which is safe and secure, and I don't think anybody doubts that, but it's an impediment to any future use of this property," said Don Hudson, the chairman of Maine Yankee's Community Advisory Panel. "Once it's out of there, then you can imagine a number of things happening."[99]

[91] February 2005. "A Model for Public Participation in Nuclear Projects." See note 82.
[92] February 2005. "A Model for Public Participation in Nuclear Projects." See note 82.
[93] February 2005. "A Model for Public Participation in Nuclear Projects." See note 82.
[94] Zambito, Thomas C. June 19, 2019. "Decades later." See note 84.
[95] Zambito, Thomas C. June 19, 2019. "Decades later." See note 84.
[96] "Maine Yankee Community Advisory Panel on Spent Nuclear Fuel Storage & Removal Charter." Maine Yankee. Accessed August 20, 2019. http://www.maineyankee.com/public/capcharter05.pdf
[97] Zambito, Thomas C. June 19, 2019. "Decades later." See note 84.
[98] Zambito, Thomas C. June 19, 2019. "Decades later." See note 84.
[99] Zambito, Thomas C. June 19, 2019. "Decades later." See note 84.

Colstrip Coal Plant, Montana

Table 12: Colstrip Coal Plant Quick Facts

Power Plant Information	
Fuel type	Coal
Closure date	2019: Units 1 & 2 2027: Units 3 & 4
Generation capacity	2,094 megawatts
Employees	320
Community Information	
Colstrip population	2,300
Rosebud County population	9,200
Estimated economic tax contribution to local community	$25 million

Colstrip power plant is a four-unit, coal-fired power plant located in the rural town of Colstrip, Montana. It is the second largest coal-fired power plant west of the Mississippi River[100] and supplies electricity to parts of Montana, Pennsylvania, Washington, Oregon, and South Dakota. As a rural community, Colstrip's economy has relied heavily on the power plant and the Rosebud coal mine that fuels it.[101]

The Colstrip plant is jointly owned by six different companies.[102] The oldest and least efficient units (unit 1 and 2) are owned equally by Talen Energy and Puget Sound Energy, whereas the newer units (unit 3 and 4) are owned by Puget Sound Energy, Talen Energy, Portland General Electric, Northwestern Energy, Avista Corporation, and PacifiCorp in order of decreasing percentage of ownership.

A Single Industry Economy

In many ways Colstrip is a "coal town," with nearly 80% of its residents depending on the power plant or coal mine for employment.[103] The plant employs roughly 320 people and the coal mine employs even more. The future of the mine is uncertain following a recent bankruptcy for the mine's owner and the eminent closure of two of the four units at the plant by the end of 2019.[104]

Taxes from the mine and power plant have contributed significantly to the town's impressive infrastructure. With 32 public parks, seven miles of trails, an Olympic-sized indoor swimming pool, and good public schools, the town has enjoyed a sense of prosperity rare to most rural communities.[105]

[100] Haggerty, Julia, Kathryn Bills Walsh, Mark Haggerty, and Jackson Rose. July 2017. "Colstrip: The Status of Key Policies and Decision Processes." Energy & Local Economies. https://headwaterseconomics.org/wp-content/uploads/Colstrip_Status_Report.pdf
[101] Wohlfeil, Samantha. June 20, 2019. "Colstrip to close two coal-fired units early." *Inlander*. https://www.inlander.com/spokane/colstrip-to-close-two-coal-fired-plants-early/Content?oid=17812536
[102] "Colstrip Steam Electric Station." Talen Energy. Accessed August 5, 2019. https://www.talenenergy.com/generation/fossil-fuels/colstrip
[103] Lutey, Tom. January 10, 2016. "At a Crossroads: Colstrip residents face uncertain future as pressures build on coal." *Billings Gazette*. https://billingsgazette.com/news/state-and-regional/montana/colstrip-residents-face-uncertain-future-as-pressures-build-on-coal/article_b726eb29-ad56-558f-a2b3-ca8f8aa171ea.html
[104] June 19, 2019. "Two coal-fired units at Montana's Colstrip Power Station to close at year's end." Energize Weekly, reprinted by EUCI. https://www.euci.com/two-coal-fired-units-at-montanas-colstrip-power-station-to-close-at-years-end/
[105] Lutey, Tom. January 10, 2016. "At a Crossroads." See note 104.

The median annual income per household in Colstrip is $84,000, roughly twice the state average.[106] The plant alone provides $25 million in property taxes to the local governments in Rosebud County. According to an economic analysis, retirement of the Colstrip units would cause a significant decrease in tax revenue for the city, county, and state of Montana.[107]

Financial Trouble for the Plant and Mine

The Colstrip power plant has faced a number of challenges in recent years. In 2008 several owners of the Colstrip plant paid $25 million to settle a groundwater contamination lawsuit brought by residents in the area.[108] In 2012, the Montana Environmental Information Center, Sierra Club, and the National Wildlife Federation sued Colstrip's owners again for coal ash water contamination and won a settlement for operational changes at the plant to limit groundwater contamination.[109] In 2013, the Sierra Club and Montana Environmental Information Center sued Talen Energy and Puget Sound Energy for breaching air quality standards.[110] In response to that latest lawsuit, the plant owners agreed to an early retirement of the plant's least economic units (unit 1 and 2) by no later than 2022 and $10 million in funding to mitigate the economic impact of closing those two units.[111]

Talen Energy, a merchant energy provider, began experiencing additional financial strain, competing with cheaper electricity generated from natural gas and renewables.[112] Then state legislation was passed in Washington and Oregon to phase out coal-generated electricity by 2025; most of the Colstrip plant's owners have service territory in those states.[113]

[106] Bernton, Hal. March 1, 2018. "As Washington state looks for cleaner power, a Montana coal town faces an uncertain future." *Seattle Times*. https://www.seattletimes.com/seattle-news/environment/as-washington-state-looks-for-cleaner-power-a-montana-coal-town-faces-an-uncertain-future/

[107] Barkey, Patrick M. June 2018. "The Economic Impact of the Early Retirement of Colstrip Units 3 & 4." Bureau of Business and Economic Research, prepared for Montana Chamber Foundation. http://www.bber.umt.edu/pubs/econ/Colstrip2018.pdf

[108] Cates-Carney, Corin. July 12, 2016. "Settlement Calls for Colstrip Units 1 & 2 To Close by 2022." *Montana Public Radio*. https://www.mtpr.org/post/settlement-calls-colstrip-units-1-2-close-2022

[109] Puckett, Karl. July 21, 2016. "Colstrip deal hailed as 'significant victory' for environment." *Great Falls Tribune*. https://www.greatfallstribune.com/story/news/local/2016/07/21/settlement-reached-control-colstrip-coal-ash-pollution/87398118/

[110] Brown, Matthew. March 6, 2013. "Colstrip power plant sued over pollution controls." *Associated Press*, reprinted in *Billings Gazette*. https://billingsgazette.com/news/state-and-regional/montana/colstrip-power-plant-sued-over-pollution-controls/article_2724c769-2000-5076-baa7-bf2584de206a.html

[111] Cates-Carney, Corin. July 12, 2016. "Settlement Calls." See note 109.

[112] Lutey, Tom. June 11, 2019. "Colstrip Units 1 and 2 will close in 2019." *Billings Gazette*. https://billingsgazette.com/news/state-and-regional/colstrip-units-and-will-close-in/article_cac5e705-d9e6-5954-af8f-9dc26b584a0e.html

[113] Lutey, Tom. January 15, 2019. "Washington state lawmakers eyeing earlier closure of Colstrip." *Billings Gazette*. https://billingsgazette.com/news/state-and-regional/washington-state-lawmakers-eyeing-earlier-closure-of-colstrip/article_a71df3b4-0daa-54fc-a998-76b0c4dd9818.html

By 2017, the owners of Colstrip's Units 3 and 4 signed on to a settlement agreement advancing retirement dates for those units to no later than 2027. [114,115,116] In June of 2019, Talen Energy unexpectedly announced that Units 1 and 2 would retire by the end of the year — three years ahead of schedule — saying that those units were no longer economic to run. The Colstrip plant's coal supply contract expires at the end of 2019. Many Colstrip residents worry that coal prices may increase, making the remaining units (Units 3 and 4) uneconomic and attractive for an even earlier retirement as well.[117]

Colstrip's Transition Story

Despite years of lawsuits and economic strain on the Colstrip power plant and the Rosebud mine, Colstrip's local and state officials hoped that the plant and mine would continue to operate and provide economic benefits for the town. Officials and the community were caught off-guard by the accelerating retirement dates for the plant's units.[118]

Many Montana state officials have largely focused attention on efforts to support the Colstrip mine and power plant and expand coal markets.[119] Montana Senate Bill 331, locally referred to as the "Save Colstrip Bill," was proposed to allow NorthWestern Energy to skirt the state's regulatory process to purchase an additional 150 MW from Colstrip's fourth unit and pass $75 million in associated ownership costs to ratepayers.[120] Though the bill was rejected, it illustrates some elected officials' efforts to support the Colstrip plant and associated mine. Colstrip's state representative Duane Ankney, a former coal miner and proponent of Bill 331, has since looked to the Trump Administration for a federal grant to explore new technologies to reduce the plant's carbon emissions.[121] According to a Colstrip community leader, "A lot of people in Colstrip are not willing to admit that the shutdowns are going to happen. They think the Trump administration is going to save them. [122]" In the meantime, officials report that Colstrip's property values in the area are falling.[123]

Clean energy advocates in Colstrip have argued that the same economics that are driving the coal industry's decline also favor less costly energy alternatives. Clean energy proponents argue that Colstrip's interconnection and robust transmission system could be used to export and distribute local

[114] Sedwick, Mary. June 23, 2019. "Montana, workers should prepare for life after coal." *Bozeman Daily Chronicle*. https://www.bozemandailychronicle.com/opinions/letters_to_editor/montana-workers-should-prepare-for-life-after-coal/article_bf2f11f8-1177-57a4-b782-7f6538d91aa6.html
[115] Wohlfeil, Samantha. June 20, 2019. "Colstrip to close two coal-fired units early." See note 102.
[116] Lutey, Tom. February 18, 2019. "Avista accelerates preparations for Colstrip exit." *Billings Gazette*. https://billingsgazette.com/news/state-and-regional/avista-accelerates-preparations-for-colstrip-exit/article_fc72186c-f036-55df-8d96-297e0c959227.html
[117] Lutey, Tom. June 11, 2019. "Colstrip Units 1 and 2 will close in 2019." See note 113.
[118] Sedwick, Mary. June 23, 2019. "Montana, workers should prepare." See note 115.
[119] Walton, Robert. April 17, 2019. "Montana House unexpectedly rejects bill to save Colstrip coal plant." Utility Dive. https://www.utilitydive.com/news/montana-house-unexpectedly-rejects-bill-to-save-colstrip-coal-plant/552885/
[120] Cates-Carney, Corin. April 8, 2019. "House Committee Hears Controversial 'Save Colstrip' Bill." *Montana Public Radio*. https://www.mtpr.org/post/house-committee-hears-controversial-save-colstrip-bill
[121] Bernton, Hal. March 1, 2018. "As Washington state looks for cleaner power." See note 107.
[122] Bernton, Hal. March 1, 2018. "As Washington state looks for cleaner power." See note 107.
[123] Larson, Aaron. June 12, 2019. "In a Surprise Announcement, Colstrip Units 1 and 2 to Close by Year-End." *Power Magazine*. https://www.powermag.com/in-a-surprise-announcement-colstrip-units-1-and-2-to-close-by-year-end/

renewable energy, retaining local electrician jobs and the community's identity as an energy provider.[124,125]

Centralia Coal Plant, Washington

Table 13: Centralia Coal Plant Quick Facts

Power Plant Information	
Fuel type	Coal
Closure date	2020, 2025
Generation capacity	1,340 megawatts
Employees	~300
Community Information	
Colstrip population	17,000
Lewis County population	78,200
Estimated economic tax contribution to local community	$25 million

Centralia is a small town in Washington that began as a logging and coal mining town. When the largest coal-fired power plant in the state opened in 1972, the town's population steadily grew to nearly 17,000 people today.[126] In 2006, the local coal mine closed and 600 workers lost their jobs. At the same time, the economic viability of coal-fired electrical generation diminished across the nation. Also in 2006, Washington State voters passed Initiative 937 to reduce utilities reliance on fossil-fuel energy sources.[127]

Group Consensus: Centralia's Success Story

This prompted then-Governor Christine Gregoire to request a negotiation between the local International Brotherhood of Electrical Workers (IBEW) labor union, representatives from power plant owner TransAlta, community members, and environmentalists to agree on the best path forward for the 300 plant workers and the economy of Centralia.[65]

Negotiations successfully delivered a settlement agreement for a plant closure. While environmental groups pushed for an early retirement of the plant due to pollution violations, the final settlement called for a staged retirement of the plant. The first boiler unit was settled to retire in 2020 and the second by the 2025, corresponding with the legislative deadline for Washington to become a coal-free energy state.[128] This compromise won support from the local IBEW union for allowing 40% of employees to reach retirement age while giving others eight years to transition before the plant closure.[129] In return, TransAlta would be allowed to explore opportunities to build natural gas generation. TransAlta also

[124] Lutey, Tom. June 11, 2019. "Colstrip Units 1 and 2 will close in 2019." See note 113.
[125] June 13, 2019. "Gazette opinion: Challenges, opportunities for Colstrip." *Billings Gazette*. https://billingsgazette.com/opinion/gazette-opinion-challenges-opportunities-for-colstrip/article_e568171f-25ea-5e44-a934-15fea155a918.html
[126] O'Leary, Sean. November 25, 2018. "A community adapts to life after coal." NW Energy Coalition. https://nwenergy.org/uncategorized/a-coal-town-transitions-to-a-clean-energy-future/
[127] O'Leary, Sean. November 25, 2018. "A community adapts to life after coal." See note 127.
[128] Martelle, Scott. January 2012. "Kick Coal, Save Jobs Right Now." *Sierra Magazine*. https://vault.sierraclub.org/sierra/201201/kick-coal-save-jobs.aspx
[129] Martelle, Scott. January 2012. "Kick Coal, Save Jobs Right Now." See note 129.

agreed to invest a total of $55 million over time into a Coal Transition Fund for the community's areas of high poverty.

The Coal Transition Fund is administered by a board of representatives from rural Lewis County, TransAlta, local economic development and labor councils, and the Northwest Energy Council. As part of this historic arrangement, the funding delivers grants to local businesses, nonprofits, and local governments to:

- Provide energy efficiency and weatherization services to residents, employees, business, nonprofits, and local governments ($10 million);
    - Fund residential energy efficiency and weatherization projects for low-to-moderate income households (up to $1 million);
- Fund education, retraining, economic development, and community enhancement projects ($15 million);
- Fund retraining and education for workers dislocated by the Centralia plant closure ($5 million); and
- Fund energy technology projects with the potential for environmental benefits within the state of Washington ($25 million).[130]

The agreement between TransAlta and other stakeholders was eventually finalized into memorandums of understanding and, ultimately, state legislation in 2015.[131]

In 2017, the federal Department of Commerce's Economic Development Administration awarded a $100,000 grant to the Industrial Park at the TransAlta site to analyze the interest and compatibility of businesses around the region to move to the Centralia area.[132]

Since the agreement, the population of Centralia has stayed relatively stable and even grown slightly.[133] The former mine located nearby the Centralia plant, now a brownfield site, will soon become a 1,000 acre, utility-scale solar array developed by TransAlta. The solar field will support roughly 300 construction jobs and make use of the existing transmission lines that formerly served the power plant.[134]

Additionally, using the retired mine land for solar provides cost savings and land use advantages. Natural Resource Defense Council senior attorney Noah Long noted in a recent article that, "Full reclamation of the site itself can be expensive." Under the Surface Mining Control and Reclamation Act

[130] Paulos, Ben. January 4, 2018. "Washington State leaves coal behind, but not its workers." Energy Transition. https://energytransition.org/2018/01/washington-state-leaves-coal-behind-but-not-its-workers/
[131] Paulos, Ben. January 4, 2018. "Washington State leaves coal behind." See note 131.
[132] Tomtas, Justyna. November 25, 2016. "Industrial Park at TransAlta Works to Land Tenants as Another Site Reaches Completion." *The Daily Chronicle*. http://www.chronline.com/industrial-park-at-transalta-works-to-land-tenants-as-another/article_21254d50-b38f-11e6-9f0e-a79fcbb44c3b.html
[133] O'Leary, Sean. November 25, 2018. "A community adapts to life after coal." See note 127.
[134] June 13, 2018. "Major Coal-Fired Power Plant in Washington to Go Solar." Natural Resources Defense Council, reprinted by EcoWatch. https://www.ecowatch.com/coal-plant-washington-solar-2577731987.html

of 1977, coal companies are required to restore land once they have finished mining it to prevent groundwater contamination and erosion—and avoid leaving behind an eyesore. “By putting solar on the land, it maintains an industrial use,” says Long. “This good use of a brownfield brings the costs of reclamation down quite a bit.”[135] It should be noted that while the solar field will create 300 jobs in the short term, it’s estimated to offer only 5 permanent jobs.[136]

Takeaways from National Case Studies of Transitioning Power Plant Communities

Collaboration and Coalitions Increase Odds of Success

- Engaging with diverse perspectives of affected stakeholders on a transition plan, including labor, environmental organizations, the utility, and policy makers, can lead to a more comprehensive and successful transition plan package, as shown in the cases of Centralia and Diablo Canyon.
- Similarly, a broad coalition of parties to a settlement agreement may increase the political viability of the agreement. This was illustrated by the broad support and relatively quick adoption of the Diablo Canyon settlement agreement by the California legislature and Governor.
- A community transition plan may require a combination of regulatory action and legislative action. As in the case of Diablo Canyon, the full package of community transition funding and programming may require enabling legislation along with approval from the Public Utilities Commission.
- Interested stakeholders, host communities, and utilities should begin discussing transition plans early to bring in all necessary stakeholders, allow time for the negotiation of an agreed upon plan, and the regulatory and legislative processes required to execute that plan.
- Utilities that own power plants are important stakeholders to engage, both as a funding source for community transitions and potential owners or partners in new economic development activities.
- A community advisory panel can be helpful to facilitate successful, two-way communication between the power plant owner and the broader community. The Maine Yankee Community Advisory Panel Report provides detailed information about the community advisory group activities and lessons learned throughout the panel’s activities.[137]

[135] Vartan, Starre. June 11, 2018. "In Washington, a Coal-Fired Power Plant Will Put Its Money on the Sun." National Resources Defense Council. https://www.nrdc.org/stories/washington-coal-fired-power-plant-will-put-its-money-sun
[136] Vartan, Starre. June 11, 2018. "In Washington, a Coal-Fired Power Plant.” See note 136.
[137] February 2005. “A Model for Public Participation in Nuclear Projects.” See note 82.

Local Investments Can Help Offset Impacts of Plant Retirements

- Existing transmission and distribution assets associated with a power plant can provide opportunities to site new replacement resources, which may help to add or maintain some jobs and other economic benefits in the area.
- Environmental remediation efforts after a plant closure should be done with the future use of that site in mind. Full environmental remediation of the plant site allows for economic opportunities in the community — both for labor and for new business development. However, partial remediation with siting of replacement energy resources or other industrial uses can moderate remediation costs, while still providing jobs and economic benefits to the community.
- Investments in energy efficiency work and other local clean energy resources may help to add or maintain jobs and other economic benefits in the area, as well as reduce the economic burden of utility bills to local residents and business.
- Investing in existing community assets and industries can create new economic opportunities for host communities. Communities may begin this work by engaging with economic development authorities and experts at the local, regional, or federal level.

Certain Characteristics of a Plant Closure Create Extra Challenges

- Abrupt closure of a power plant poses additional challenges as communities may not be well-situated or prepared to execute an adequate transition effort. The Maine Yankee, Colstrip, and Centralia plants closed early and very abruptly, which had negative implications for the towns' preparation and readiness for a smooth transition. Abrupt closure appears particularly common for coal-fired power plants due to the current economic and environmental pressures on coal.
- Nuclear plant retirements include complicated and long decommissioning and remediation processes. Those processes can create short-term, local job opportunities, but can limit land use and redevelopment options. Further, nuclear plants with onsite spent fuel storage will likely require federal action before spent fuel can be moved. Without federal action, spent fuel may continue to be stored on-site long after a plant closure, potentially limiting opportunities for future land use and redevelopment.
- Community or local governmental resistance to accepting that a plant will retire can delay efforts to transition. In the case of Colstrip, even with several economic analyses highlighting early retirement impacts and mitigation strategies, implementation of those recommendations were hindered by political will to support the plants.
- Cutting local services abruptly due to decreased tax revenue after a plant closure can be challenging and upsetting for community members and may lead to tension at the local government level.

Bibliography

Benn, Annie, Paul Bodnar, James Mitchell, and Jeff Waller. September 2018. “Managing the Coal Capital Transition: Collaborative Opportunities for Asset Owners, Policymakers, and Environmental Advocates.” Rocky Mountain Institute. https://rmi.org/wp-content/uploads/2018/09/RMI_Managing_the_Coal_Capital_Transition_2018.pdf

Dennis, Brady and Steven Mufson. March 28, 2019. “In small towns across the nation, the death of a coal plant leaves an unmistakable void.” *The Washington Post*. https://www.washingtonpost.com/national/health-science/thats-what-happens-when-a-big-plant-shuts-down-in-a-small-town/2019/03/28/57d62700-4a57-11e9-9663-00ac73f49662_story.html?noredirect=on

Dillon, Caitlin. August 2017. “In Transition: Stories from Coal Plant Communities.” Delta Institute. https://delta-institute.org/delta/wp-content/uploads/In-Transition-Stories-From-Coal-Plant-Communities-Delta-Institute-Aug-2017.pdf

Donaue, Marie and John Farrell. March 28, 2019. “A Massachusetts Town Realizes a Community Vision to Transition from Coal to Sol.” Local Energy Rules Podcast, Episode 73. https://ilsr.org/community-vision-transition-coal-sol-holyoke-mass-lena-entin-ler-73/

Haggerty, Julia, Mark Haggerty, Kelli Roemer, and Jackson Rose. August 2018. "Planning for the local impacts of coal facility closure: Emerging strategies in the U.S. West." *Resources Policy* (57): 69–80. https://doi.org/10.1016/j.resourpol.2018.01.010

Hamilton, Lisa Anne, Valova Raaina, and Karl Rabago. March 2017. “Transition Support Mechanisms for Communities Facing Full or Partial Coal Power Plant Retirement in New York.” Pace University. https://digitalcommons.pace.edu/cgi/viewcontent.cgi?article=1009&context=environmental

Northern Plains Resource Council and International Brotherhood of Electrical Workers (Local 1638). July 2018. “Doing it Right, Colstrip’s Bright Future with Clean Up.” https://northernplains.org/wp-content/uploads/2018/07/DoingItRight_FullStudy_FNL_WEB.pdf

Power, Mick, Michael G. Williams, Kari Mosley, Jeffery Frankel, and Philip Hanser. July 9, 2015. “Managing the Employment Impact of Energy Transition in Pennsylvania Coal Country.” BlueGreen Alliance. https://www.bluegreenalliance.org/wp-content/uploads/2016/08/Managing-the-Employment-Impact-of-Energy-Transition-in-Pennsylvania-Coal-Country-vFINAL.pdf

Rosenfeld, Ethan. 2015. “Transition Plans for Coal-Fired Power Plant Closings: Stability, Opportunity, & Community.” *Journal of Energy & Environmental Law* (6, 2): 71–82. https://gwjeel.com/wp-content/uploads/2015/07/jeel_vol6_issue2_rosenfeld.pdf

Sanzillo, Tom. June 2017. “A Transition Plan for Communities Affected by the Closings of Navajo Generating Station and Kayenta Mine.” Institute for Energy Economics and Financial Analysis. http://ieefa.org/wp-content/uploads/2017/06/IEEFA-Transition-Plan-for-Navajo-Generating-Station-and-Kayenta-Mine-060617.pdf

Siegner, Katie. January 23, 2019. “Flipping the Switch: A coal plant’s retirement and a community’s response (Part 1).” *Sage Magazine*. http://www.sagemagazine.org/flipping-the-switch-a-coal-plant-retirement-and-a-communitys-response-part-i/

Just Transition Fund. April 2019. “How to Get Started: A Guide to Help Local Governments Engage on Coal Plant Transition.” http://www.justtransitionfund.org/

Trahant, Mark. March 25, 2019. “The Navajo Nation’s Transition Beyond Coal ‘Starts now.’” *Indian Country Today*. https://newsmaven.io/indiancountrytoday/news/the-navajo-nation-s-transition-beyond-coal-starts-now-xGu5FYYqoUOzdLwcgGPhOA/

Minnesota Department of Human Rights
Affirmative Action Plan Progress Report - AUUA

Date 07/23/2020

Worksheet for comparing incumbency to availability and setting goals for the updcoming AA Plan year to correct underutilizations

Company name: Xcel Energy

	A	B		C				D		E			
		Women						**People of Color**					
Job Group	**Total Employees in Job Group**	**Utilization Number**	**%**	**Availability %**	**Number**	**Number Under-utilized**	**Annual % Goal**	**Utilization Number**	**%**	**Availability %**	**Number**	**Number Under-utilized**	**Annual % Goal**
Officials and Managers	707	148	20.9	4.30	30	0		39	5.5	1.00	7	0	
Professionals	1718	527	30.7	19.90	341	0		178	10.4	0.70	12	0	
Technicians	419	40	9.5	0.00	0	0		20	4.8	0.00	0	0	
Sales	0	0		0.00				0		0.00			
Office/Clerical	395	268	67.8	50.80	200	0		73	18.5	6.60	26	0	
Skilled Craft	1138	33	2.9	2.70	30	0		42	3.7	2.00	22	0	
Operatives	154	5	3.2	0.00	0	0		6	3.9	0.00	0	0	
Laborers	61	5	8.2	1.50	0	0		6	9.8	1.20	0	0	
Service Workers	77	14	18.2	2.60	2	0		7	9.1	0.00	0	0	
Totals	4669	1040			603	0		371			67	0	

	F
Job Group	**Source of Availability Percentages**
Officials and Managers	2010 Census/MN; 0300
Professionals	2010 Census/MN; 1430
Technicians	2010 Census/MN; 1930
Sales	n/a
Office/Clerical	2010 Census/MN; 5030
Skilled Craft	2010 Census/MN; 635
Operatives	2010 Census/MN; 7100
Laborers	2010 Census/MN; 6320
Service Workers	2010 Census/MN; 9520

MDHR AA Progress Report (AUUA Update) - 6/2018

Follow the instructions below to complete this worksheet

A For each Job Group, type in the total number of employees indicated in the Annual Compliance Report on the last day of the reporting period. For information about the Job Groups and what Job Titles to include under them, see the census information or the Minnesota Department of Human Rights' (MDHR) *How to Develop an Affirmative Action Plan* manual, located on MDHR's website at mn.gov/mdhr under *Certificates*.

B Type in the total number of women employed in each Job Group.

C Insert the Availability Percentage for Women for each Job Group. You can find this information in (a) the 2010 census data affirmative action statistics for the county(ies) in which your company is located, or (b) the Availability Percentages that resulted from your Two-Factor Analysis and/or Composite Availability Analysis found in your Affirmative Action (AA) Plan. You should review the AUUA (and Two-Factor Analysis and/or Composite Availability Analysis, if applicable found in your company'scurrent AA Plan that was approved by the Minnesota Department of Human Rights.

NOTE: If you use Availability Percentages that resulted from a Two-Factor and/or Composite Availability Analysis, you must submit the updated Two-Factor and/or Composite Availability Analyses along with the Annual Compliance Report Packet These forms can be found on MDHR's website at mn.gov/mdhr under *Certificates - Forms & Worksheets.*

D Type in the total number of minorities in each Job Group.

E Insert the Availability Percentage for Minorities for each Job Group. . You can find this information in (a) the 2010 census data affirmative action statistics for the county(ies) in which your company is located, or (b) the Availability Percentages that resulted from your Two-Factor Analysis and/or Composite Availability Analysis found in your Affirmative Action (AA) Plan. You should review the AUUA (and Two-Factor Analysis and/or Composite Availability Analysis, if applicable found in your company'scurrent AA Plan that was approved by the Minnesota Department of Human Rights. To find the Availability Percentages, go to MN Dept. of Employment and Comic Development (DEED) at https://mn.gov/deed/data/data-tools/affirmative-action-statistics/

NOTE: If you use Availability Percentages that resulted from a Two-Factor and/or Composite Availability Analysis, you must submit the updated Two-Factor and/or Composite Availability Analyses along with the Annual Compliance Report Packet These forms can be found on MDHR's website at mn.gov/mdhr under *Certificates - Forms & Worksheets.*

F Insert the the Census Occupation Code (COC) or Standard Occupational Code (SOC) used for each Job Group listed in the AUUA above, and the geographic source of the availability percentages used from DEED's website or the U.S. Census Bureau. For example, if you used DEED's 2010 Census data statistics for the Minneapolis-St. Paul Metropolitan Statistical Area (MSA),

NOTE: You must use the 100% Availability Percentage with the WHOLE PERSON RULE to determine underutilizations. This form has this methodology built into the calculation.

Energy Utility Diversity Stakeholder Group Report - Submitted January 15, 2020

January 15, 2020

To:

Sen. David J. Osmek, Chair, Energy and Utilities Finance and Policy

Rep. Jean Wagenius, Chair, Energy and Climate Finance and Policy

Sen. Erik Simonson, Minority Lead, Energy and Utilities Finance and Policy

Rep. Chris Swedzinski, Minority Lead, Energy and Climate Finance and Policy

Re: Report from the Energy Utility Diversity Stakeholder Group

Dear Legislative Leaders:

We are pleased to submit a report prepared in accord with Minnesota Session Laws, 2019, First Special Session, Chapter 7, Article 11, Section 13, which directed the Minnesota Public Utilities Commission to convene a stakeholder group to examine the challenges and opportunities for Minnesota's energy utilities to attract a diverse workforce with the skills needed to advance a 21st century industry and to increase supplier diversity of energy utilities.

Writing this report was a participatory process in which a diverse and highly engaged group of stakeholders shaped the report's overall essence and content. It was important to represent many unique and diverse interests and perspectives offered by the Energy Utility Diversity Group (EUDG). We hope that the legislature will find it useful and we look forward to working together to make progress in this area. We appreciate the opportunity.

Respectfully Submitted,

EUDG Executive Committee

Jose L. Perez, Chair (Hispanics In Energy)

Anita Grace, Co-Vice Chair (Grace Multicultural)

Jennifer Peterson, Co-Vice Chair (Minnesota Power)

Karen DeYoung, Consultant (DeYoung Consulting Services)

Energy Utility Diversity Stakeholder Group Report - Submitted January 15, 2020

Executive Summary

Introduction

Minnesota Session Laws, 2019, First Special Session, Chapter 7, Article 11, Section 13 directed the Minnesota Public Utilities Commission to convene a stakeholder group to examine the challenges and opportunities for Minnesota's energy utilities to attract a diverse workforce with the skills needed to advance a 21st century industry and to increase supplier diversity of energy utilities. The law requires the stakeholder group to issue a report to the Legislature by January 15, 2020 identifying its findings and recommendations for establishing a more diverse workforce and increasing supplier diversity within the energy sector. To that end, the resulting Energy Utility Diversity Group (EUDG) was to address the following provisions:

1. Examine current and projected employment in the energy utility sector;
2. Provide information on possible approaches to assist workers and energy utilities to develop a diverse workforce that has the skills to build, maintain, and operate the electricity system of the future;
3. Review key trends that have shaped employment in this sector and the demographics of the sector, including the underrepresentation of women, veterans, and minorities in employment and leadership;
4. Identify the challenges to replacing retiring workers;
5. Examine the imbalance of available worker skills to utility workforce needs;
6. Identify the challenges and possible approaches to increasing supplier diversity; and
7. Consider whether information regarding workforce and supplier diversity should be included and considered as part of any resource plan filed by a utility with the commission.

The full EUDG met five times with many conference calls and sub meetings in between. Two subcommittee groups were created to specifically address workforce and supplier diversity issues respectively. Subcommittees bore the responsibility of background research in their area of focus, writing and offering recommendations; their summaries were then brought to the full EUDG group for discussion.

This resulting report describes issues and viewpoints discussed by EUDG members as they completed their charge. Stakeholders brought to bear extensive experience, expertise and time, and they worked in good faith to be as complete and accurate as possible and to arrive at constructive observations, findings and conclusions.

Given time and geographic limitations, not all affected stakeholders may have had the ability to participate in all meetings. Also, the report relies largely on secondary source data and stakeholder viewpoints. It was not the result of primary research or fact finding through scientific analysis or adjudication. To the extent any items are identified as “findings,” “conclusions” or like terminology, those terms are used informally, and they were not the result of a scientific or adjudicated process.

Many of the statements in the report may not have been supported by every stakeholder so it may not be the result of unanimity nor consensus on each statement.

Types of Utilities

To ensure a universal and clear understanding of the entities that are the focus of this report, we begin with a brief description of the types of utilities and their contexts. Minnesota Statute §216B.01 defines three different types of utilities, defined by ownership: investor-owned, municipally owned and cooperatively owned. Per the statute, differing ownership structures result in differing types of regulation and governance structures for the utilities.

Further, for purposes of this report and as noted in the statute, there are two general industries, defined by the type of product delivered: *electricity* or *natural gas*.

The governance type of any utility does not determine the geography it may serve. Within Minnesota, there are investor owned, municipal, and cooperative utilities that serve some of the most sparsely populated and rural parts of the state. It was recognized during discussions that the specific demographics of the geographies being served may impact the approaches that might be considered for any utility and that because of these differences, one-size-fits-all approaches would not likely be successful.

Minnesota Energy Utility Overview

Beyond the utility structures indicated above, other energy companies are involved when electric utilities purchase power from independent power producers that own electric generation facilities. These energy companies are not subject to the same regulation the state utilities are; instead, the utility purchasing the power from such energy companies must show that the proposed purchase is just and reasonable.

Minnesota’s utilities do more than deliver affordable, reliable electric and natural gas service to homes, businesses, and public institutions across the state. Investor-owned, cooperative and municipal energy utilities also provide economic opportunity to hundreds of Minnesota firms and communities, and tens of thousands of workers. The economic development opportunities created by the utility sector are a public benefit that should be made available on an equitable basis to Minnesotans of diverse backgrounds.

Workforce Diversity

The Workforce Diversity Subcommittee was charged with addressing provisions one through five. After examining the current state of diversity in the electric and gas utilities industries, along with the current workforce needs, the group drafted the following findings and recommendations.

Findings and recommendations

The following findings and recommendations are intended to increase workforce diversity. Long term, it is hoped that these efforts will strengthen and enhance economic development in the communities that utilities serve; providing employment opportunities helps to ensure the viability of those communities.

Findings

- Minnesota energy utilities are organized in three separate categories with unique geographic presence, governance and demographics.
- The energy sector is changing, including a movement from large central station power plants toward renewable and distributed energy resources. Utility customers' preferences for interactions with their energy provider have also changed. These developments require Minnesota's energy utilities to anticipate changes to the sector's workforce and procurement needs, as well. Given these factors, along with Minnesota's changing demographics, tapping diverse communities that have historically been underrepresented in utility and other areas of employment may be a means of addressing these needs.
- Though utilities have conducted outreach efforts, a lack of awareness about the industry, particularly within underrepresented communities, can pose a challenge to recruitment efforts.
- A number of employment barriers may limit the success of efforts to hire more diverse candidates.
- Existing cross-sector partnerships between utilities and industry experts, academic institutions and others provide a model for training and development of diverse populations.
- Shifts in technology are expected to create an increase in technician roles, roles supporting changes to the grid, and other technology and data-focused roles. Therefore, the lack of diversity in the education pipeline for STEM educational programs must also be considered.
- The Center for Energy Workforce Development's (CEWD) projection of retirements and expected attrition can pose a challenge as but also offer opportunities for utilities to seek new workers from diverse populations.
- The drop in industry workforce training programs in the 1980's, and the trend away from technical schools in the 1990's, have contributed to a skills gap issue. This gap is particularly acute in diverse communities, where additional training is needed to build up the talent pipeline.

Recommendations

- **Data collection:** Collecting data allows utilities to know where they currently sit, as well as inform their goals for the future. It is recommended that utilities continue to use required affirmative action plans as a starting place for strategic planning. For utilities that are not required to file demographic information with the State, the affirmative action reporting templates and guidelines could voluntarily be used to help utilities track demographics information.

- **Build on current efforts in engagement, building pipelines, training and hiring practices**: Energy utilities should continue their existing recruitment, training, retention (including professional development, cultural competency, and skill development), and outreach programs and allocate resources for programs to cultivate diversity at all levels.
    - **Emphasize ongoing efforts**: Rather than one-time engagement efforts, there must be an ongoing dialogue between industry stakeholders, educational entities and the communities they serve.
    - **Build pipelines**: Career exposure should start during high school or earlier for students and young people, and employers should establish and maintain relationships with targeted schools and populations and engage consistently and regularly with students over time. This includes educating young people on the energy industry as well as providing tools and programs to gain fundamental knowledge of the industry. Establish programs in middle and high schools where students can explore and learn about the industry and guide students into the post-secondary programs that will provide the education they need to obtain employment in the industry. This should be done while continually tracking and maintaining contact with these young people through industry mentors or other contacts.
    - **Expand training**: It is important to expand training opportunities for diverse populations, including registered apprenticeships, paid internships, and paid fellowships**,** to help identify and nurture professional skills.
    - **Analysis of hiring requirements and reducing barriers**: Energy utilities should review their existing recruitment and hiring practices to ensure that job-entry requirements are appropriately aligned with the actual requirements of the job. Special attention should be paid to acknowledging and removing existing barriers.
- **Partner with other utilities:** Recognizing that different utilities have different levels of resources and staff capacity, some utilities might work jointly with other utilities to allocate resources and funding to explore innovative outreach and awareness models, including:
    - **New methods of reaching particular diverse groups through existing energy services**. For example, utilities might integrate information about career opportunities into the provision of their services such as energy efficiency upgrades in underrepresented communities.
    - **Coordinated and targeted marketing campaigns to build awareness of the utility industry**, especially within low-income communities, immigrant communities, and communities of color.
    - **Establishing "energy experience centers" located in accessible locations**, including Opportunity Zones, within underrepresented communities in order to ensure access and expose youth and adults to energy technologies and educational opportunities, and to create hubs where interested individuals and businesses could connect with utilities, vendors, and training providers
    - **Expanding and/or replicating community and school-based programs that support STEM learning**, like the CEWD school curriculum or mentoring programs such as the Future Cities Competition, which pairs energy utility professionals with students to

provide STEM tutoring and career pathways guidance. There has been a re-emergence of technical education programs at the high school level. Utilities can further support STEM education by engaging with these facilities.

- **Investment from the State:** Solutions likely will not come from the energy sector alone.
  - **It is important for the State of Minnesota and school districts serving diverse populations to invest in closing achievement and opportunity gaps** and improving retention and graduation rates for racial and ethnic minority students in low-income/under-resourced households, and students from immigrant populations.
  - **Addressing transportation barriers** will likely also need assistance from entities outside the utility sector to help ensure that potential employees have reasonable access to training and jobs.
- **Recognize positive impact of utility ownership:** The impact of diversity efforts in the regulated electric utility sector may be greatest where generation and transmission assets are owned by utilities because third-party owners are not currently held to the same equity and transparency standards. Minnesota's agencies, boards and commissions are encouraged to recognize and weigh the impact of utility ownership on diversity where consistent with their legal authority. The legislature should also consider taking steps to ensure that Independent Power Producers and other beneficiaries of ratepayer-funded subsidies for distributed generation and energy efficiency programs, including Community Solar Gardens, be required to meet the standards as regulated utilities.
- **Partner with non-utilities**: Energy utilities should explore partnering with industry partners, building trades unions, academic institutions, community-based organizations, and workforce agencies to identify and develop career pipelines, while making the training and employment opportunities more accessible to underrepresented populations.
- **Continue this process**: The EUDG can continue their work to gather many stakeholders to discuss challenges, successes, resources and best practices in regards to increasing workforce diversity.

Supplier Diversity

Per the Session Law, the scope of supplier diversity portion of this report is limited to provision six: identify the challenges and possible approaches to increasing supplier diversity.

Among multiple types of utility providers, there are significant differences in size and the geographic location of customers served. There are three (3) providers who have established supplier diversity programs; most utilities do not because they don't have enough resources/personnel to start or manage such programs. Most of the utilities, however, do place a great emphasis on buying from suppliers that are located within their respective service territories. All the utilities recognize the importance of their supplier base being reflective of the communities they serve.

Participation among the utilities (investor owned, municipal, cooperatives) should be voluntary.

Findings and recommendations

Based on their research and discussions, the EUDG identified the following findings and recommendations to increase supplier diversity:

Findings: Challenges to the Utilities

Following are challenges identified by the EUDG that utilities address in their efforts to increase supplier diversity:

- Supplier programs need to be as “diverse” as the communities the utility serves; therefore, the desire to buy local or purchase from the investor owned/cooperative/municipal customer base is as important as increasing opportunities for new suppliers who hold diversity certification(s).
- Creating supplier diversity programs for most utilities presents a challenge given the lack of budget, tracking software, and employee resources. Ultimately, utilities could seek to recover costs incurred to launch and manage a program from rate payers.
- Considering that many utilities do not currently track diverse spend, there is no baseline for these utilities to start from and compare to. Baselines for each utility for increasing opportunities for diverse suppliers should be determined in the initial year(s) before thresholds and goals to increase opportunities can be set for future years.
- Many utilities have limited outreach resources to identify diverse suppliers (see Workforce Diversity section).
- Large amounts of diverse spend are specifically project driven (wind/solar additions) and once projects are completed it’s hard to immediately replace that same level of spend.
- A utility may increase bid opportunities for diverse suppliers (when possible and when identifiable); however, corporate or board policy may require the utility to award to the lowest bidder which will impact whether the utility is able to increase spend. The goals should be based on opportunities to bid and not mandated spend. The diverse contractor must also be compliant with the utility’s internal requirements - such as safety, insurance, and warranty.
- Past purchasing decisions often dictate future purchasing decisions for a utility, where the utility is tied to the previous vendor due to proprietary design or equipment standardization reasons.

Findings: Challenges to Diverse Suppliers

Diverse suppliers, in turn, address their own challenges to meet utilities’ needs.

- Newly established diverse suppliers who have diversity certification(s) are often unable to meet the scale and scope needs for large utilities and need to identify Tier II opportunities with prime contractors in order to gain experience and grow their business.
- Some diverse suppliers may have limited access to capital or outside funding; while others are very large and are not limited in these respects.
- Solicitations are not publicized broadly in diverse communities.

- There is a lack of training or helplines available to explain the process to businesses who are new to the industry or the procurement process.
- There is a lack of encouragement for young, diverse individuals to expose them to the idea of creating their own businesses

Recommendations

Utilities can use a number of strategies to increase supplier diversity:

Work in partnership. Utilities can work in partnership with other entities:

- Those utilities in the state that have existing Supplier Diversity programs can share their list of diverse suppliers with other utilities across state;
- They can work jointly to engage with diverse suppliers; and they can share best practices.
- Community groups can also serve as partners by offering ideas or activities that results in enhanced supplier diversity outcomes.
- Additionally, utilities can solicit information from existing prime contractors on the subcontractors that are used and identify diverse suppliers in process.
- Finally, utilities can ask utility credit card providers to identify diverse suppliers that they are obtaining goods/services from currently.

Introduction

Minnesota Session Laws, 2019, First Special Session, Chapter 7, Article 11, Section 13, directed the Minnesota Public Utilities Commission to convene a stakeholder group to examine the challenges and opportunities for Minnesota's energy utilities to attract a diverse workforce with the skills needed to advance a 21st-century industry and to increase supplier diversity of energy utilities. The law requires the stakeholder group to issue a report to the Legislature by January 15, 2020, identifying its findings and recommendations for establishing a more diverse workforce and increasing supplier diversity within the energy utility sector. Prior to convening this group, the Commission invited leaders from a broad and diverse array of groups and organizations across the State, including Energy utilities (Investor Owned, Co-Ops and Municipalities), African American/Somali, Asian/Hmong, American Indian, Latino, women, veterans, organized labor, trade associations, and academia.

Over 100 individuals representing utilities or other energy-sector and community stakeholders signed up to participate throughout the process; 71 individuals engaged in meetings and providing input for this report. The stakeholder group has been identified as the Energy Utility Diversity Group (EUDG).

The full EUDG met five times with many conference calls and submeetings in between. Two subcommittee groups were created to specifically address workforce- and supplier-diversity issues. Subcommittees bore the responsibility of background research in their area of focus, writing and offering recommendations; their summaries were then brought to the full EUDG group for discussion.

Purpose and Use

EUDG’s task has been to respond directly to the Session Law:

1. Examine current and projected employment in the energy-utility sector;
2. Provide information on possible approaches to assist workers and energy utilities to develop a diverse workforce that has the skills to build, maintain, and operate the electricity system of the future;
3. Review key trends that have shaped employment in this sector and the demographics of the sector, including the underrepresentation of women, veterans, and minorities in employment and leadership;
4. Identify the challenges to replacing retiring workers;
5. Examine the imbalance of available worker skills to utility-workforce needs;
6. Identify the challenges and possible approaches to increasing supplier diversity; and
7. Consider whether information regarding workforce and supplier diversity should be included and considered as part of any resource plan filed by a utility with the commission.

By January 15, 2020, the EUDG report must be presented to the chairs and ranking minority members of the House of Representatives and Senate committees with jurisdiction over energy policy and finance; included would be its findings and recommendations for establishing a more diverse workforce and increasing supplier diversity within the energy utility sector.

This report describes issues and viewpoints discussed by members of the stakeholder group. Stakeholders brought to bear extensive experience, expertise, and time, and they worked in good faith to be as complete and accurate as possible and to arrive at constructive observations, findings, and conclusions.

Given time and geographic limitations, not all affected stakeholders may have had the ability to participate in all meetings. Also, the report relies largely on secondary source data and stakeholder viewpoints. It was not the result of primary research or fact finding through scientific analysis or adjudication. To the extent any items are identified as "findings," "conclusions," or like terminology, those terms are used informally, and they were not the result of a scientific or adjudicated process.

Many of the statements in the report may not have been supported by every stakeholder, so the report may not be the result of unanimity or consensus on each statement.

Report Structure

This report begins with a level setting by defining the types of utilities in Minnesota and the ways in which they are governed and regulated. This is followed by a discussion addressing each provision of the Minnesota Session Law, including findings and recommendations for the two areas of focus: supplier and workforce diversity.

Types of Utilities

To ensure a universal and clear understanding of the entities that are the focus of this report, we begin by defining the types of utilities in Minnesota, their regulatory status, and their governance structures.

Minnesota Statute §216B.01 defines three different types of utilities, defined by ownership: investor-owned, municipally owned, and cooperatively owned. Per the statute, differing ownership structures result in differing types of regulation and governance structures for the utilities:

Table 1: Different Governance Structures of Utilities

Ownership Structure	Regulatory Status	Governance Structure
Investor-owned utilities (IOU's)	Subject to rate and resource regulation by the Minnesota Public Utilities Commission (MPUC) under Chapter 216B of Minnesota Statutes. Investor-owned utilities may also be subject to the authority of utility commissions of other states for service to customers in those other states. They are also subject to regulation by the Federal Energy Regulatory Commission for rates and matters within the scope of that agency's authority.	≠ Companies that raise equity capital for infrastructure through investors charge their customers a regulated rate of return on their investment ≠ Governed by boards of directors
Municipal utilities	Regulated by the city council or council-appointed utility commission and thus responsive to the citizens (voters) who are their customers.	≠ Municipal (city-owned) entities are sometimes referred to as public power, but they are not a public utility, which by statute generally refers to IOUs only. ≠ Governed by either the city council or a local utility commission appointed by the city council. ≠ Municipal utilities may provide some generation but have a variety of means to acquire power, either directly or through a power agency. The utility is then responsible for distribution to customers within its designated service territory. ≠ Numerous state and federal statutory and regulatory requirements apply to municipal utilities.

Cooperative utilities	Regulated and controlled by their members as identified under Chapter 308A	≠ Cooperative entities are sometimes referred to as public power, but they are not a public utility, which by statute generally refers to IOUs only. ≠ Established through the Rural Electrification Administration in the late 1930s as a primary means of providing electric service and economic development to rural communities. ≠ Nonprofit, member-owned utilities that are governed by a Board of Directors that is locally elected and members of the cooperative utility as set forth in cooperative by-laws. The utility is then responsible for distribution to customers within its designated service territory. ≠ Numerous state and federal statutory and regulatory requirements apply to cooperative utilities.

Further, for purposes of this report and as noted in the statute, there are two general industries, defined by the type of product delivered: *electricity* or *natural gas*.

All types of electric utilities have the privilege and obligation to serve all customers within a defined service territory under Minn. Stat. 216B.37. Natural gas utilities do not have defined service territories.

The governance type of any utility does not determine the geography it may serve. Within Minnesota, there are investor-owned, municipal, and cooperative utilities that serve some of the most sparsely populated and rural parts of the state. It was recognized during discussions that the specific demographics of the geographies being served may impact the approaches that might be considered for any utility and that because of these differences, one-size-fits-all approaches were not likely to be successful.

Integrated Resource Plans

Only the investor-owned electric utilities and generation-and-transmission (G&T) entities file integrated resource plans with the MPUC.[1] Integrated Resource Planning (also known as IRP or a resource plan), is

[1] Natural gas utilities do not file integrated resource plans. Further, Minnesota statute §216B.2422 grants the MPUC differing authority over integrated resource plans filed by different types of utilities. Specifically, the MPUC

the process by which a utility, the Commission, and stakeholders examine a utility's current and planned electricity generation to meet customers' energy needs for the upcoming 15 years. These plans include forecasts of customers' energy needs, and they are aimed at determining the size, type, and timing of new generation resources that may be required. While IRPs generally do not involve any acquisition of a specific resource, they may be used in certificates of need for any entity requesting to build a large energy facility or, for investor-owned utilities only, in other proceedings to acquire new resources through acquisition or power-purchase agreements (PPAs).

Independent Power Producers

Beyond the utility structures indicated above, other energy companies are involved when electric utilities purchase power from independent power producers that own electricity-generation facilities. These energy companies are not subject to the same regulation as the state utilities; instead, the utility purchasing the power from such energy companies must show that the proposed purchase is just and reasonable.

Community Solar Gardens are an example of an independent power producer. In this unique circumstance, Xcel Energy is required to purchase power from Community Solar Gardens that are not owned by Xcel Energy. Xcel Energy is not required to show that such purchases are just and reasonable, as the rates are set by an administrative process. Xcel Energy is also not responsible for the marketing, customer communications, workforce development, or labor agreements in Solar Gardens developed by other entities.

Minnesota's utilities do more than deliver affordable, reliable electric and natural gas service to homes, businesses, and public institutions across the state. Investor-owned, cooperative, and municipal energy utilities also provide economic opportunity to hundreds of Minnesota firms and communities and tens of thousands of workers. The economic development opportunities created by the utility sector are a public benefit that should be made available on an equitable basis to Minnesotans of diverse backgrounds.

Minnesota's system of energy regulation, which incorporates municipal, cooperative, and regulated private ownership of utilities, is designed to ensure public transparency and control over entities that deliver essential public services.

It is important to keep in mind, however, that there are economic and regulatory constraints on the ability of Minnesota's utility sector to deliver economic opportunity and advance equity. Utilities must seek board approval—and in the case of investor-owned utilities, regulatory approval—to recover the cost of expenditures through rates, and they can be required by their governance, regulation, and the legislature to purchase power from third parties that are not necessarily held to the same standard when it comes to equity and transparency. For example, during its first meeting, the group received a

---

"shall approve, reject, or modify the plan" of an investor-owned utility, whereas the MPUC's decisions for cooperative and municipal G&Ts "shall be advisory."

detailed briefing from Xcel Energy on the status of the utility's diversity initiatives, including the workforce that builds and maintains Xcel Energy-owned generation infrastructure.

No equivalent information was available, however, for the companies and energy facilities that generate power for Xcel Energy customers under PPAs or through independent power producers, such as the Community Solar Gardens program. Further, it is not clear that regulators have any authority to require owners of Community Solar Gardens or other ratepayer-supported distributed generation resources to provide information or to make efforts to increase diversity or equity in choice of workforce or suppliers. The potential of Minnesota's regulated utilities to advance diversity and equity may be limited to the degree that third-party owners are not held to the same standard or to the degree that distributed energy infrastructure is being developed and operated without strong regulatory oversight.

Workforce Diversity

Current State of Workforce Diversity in the Electric and Gas Utility Industries

Employment data by race, ethnicity, gender, and veteran status was not collected as part of this examination. However, Minnesota's current population is almost 20% minority, and that percentage is projected to grow to almost 25% in the next 15 years.[2] There was general agreement among EUDG participants that more work is needed to ensure that racial and ethnic minorities and women are adequately represented in the utility workforce. It is also generally understood that more work is needed to increase diversity in leadership, such as corporate boards or governing boards of energy organizations and executive level positions. Some progress is noted, however. Half of the Board of Directors for ALLETE, for example, are women. Also, some racial minorities are present in executive-level management positions of these organizations. It was also recognized that state-wide demographic statistics don't represent the wide variation in the demographics of various regions of the state. For example, many of the state's sparsely populated rural regions are largely homogeneous with respect to race. Therefore, increasing racial and ethnic diversity for utilities serving rural populations may depend as much on recruiting diverse citizens to these communities as it does on recruiting diverse workers to this industry. With regard to racial, ethnic, and gender diversity, however, it is apparent that people of color are seriously underrepresented in the energy utility sector's workforce. This might be remedied by bringing more awareness through partnerships and outreach.

EUDG Definition of Workforce Diversity

EUDG participants understood diversity to mean equal participation for anyone regardless of race, color, religion, sex (including gender identity, sexual orientation, and pregnancy), national origin, age, disability

[2] Minnesota State Demographer

or genetic information , as defined by the Equal Employment Opportunity Commission.[3] In identifying diverse populations, the EUDG went beyond the official government definitions to include veterans, rural populations with limited access to family-supporting job opportunities, and individuals facing other barriers to employment including, but not limited to, a history of involvement in the criminal-justice system, and groups representing communities served by Minnesota's energy utilities, including ratepayers and communities that host plants and other electric or gas infrastructure.

Changing Workforce Needs

The energy-utility sector is changing. The electric grid is shifting from one that relies on a limited number of large central station power plantsto one that incorporates more dispersed renewable energy resources. This transformation away from large central-station power plants and the incorporation of renewable and distributed resources has effects on utility workforce and procurement needs, both today and in the future.

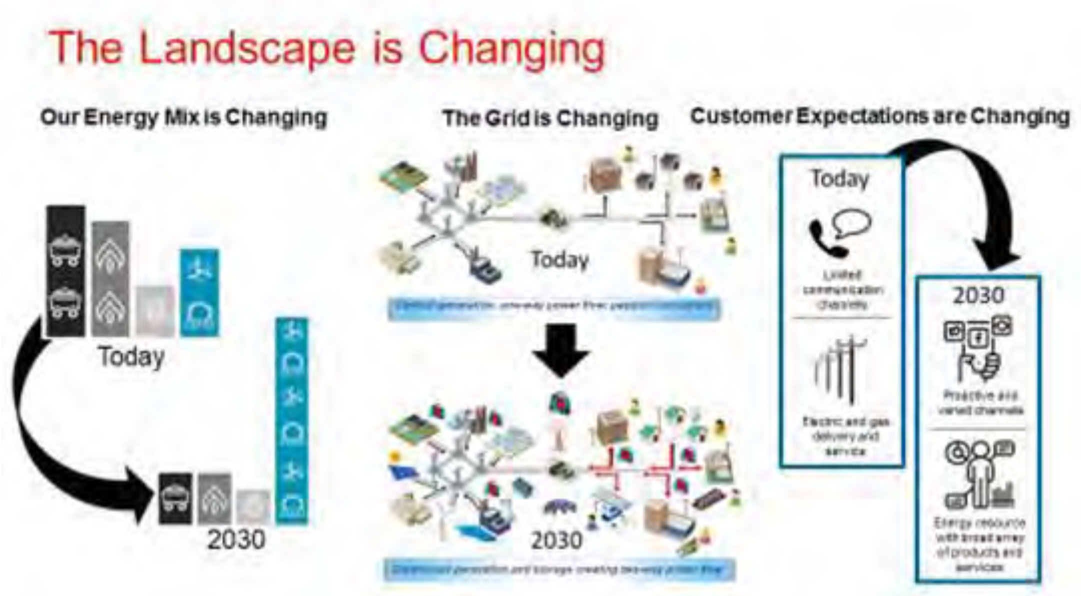
The sector is also seeing a change in how utility customers want to interact with their energy providers. During this report-writing process, utilities indicated that their customers want more proactive service, quicker responses to outages and other needs, as well as the ability to have more control over the kind of energy produced and used. To fulfill these changes, Minnesota's energy utilities anticipate changes to our workforce needs as well.

No one-size-fits-all solution will help utilities to increase their workforce diversity. As described in the Introduction, utilities have different governance structures that inform their regulatory decisions. Population size and demographics in the communities that utilities serve can vary greatly. Finally, utilities experience different circumstances, such as the number of employees expected to retire in the next ten years, changes in their infrastructure, etc.

At the same time, utilities may be able to collaborate and share approaches that work well, such as using resources (discussed below) to promote energy jobs, and making efforts to build inclusive cultures.

[3] U.S. Equal Employment Opportunity Commission https://www.eeoc.gov/laws/practices/

Figure 1: The Changing Energy Utility Sector[4]



Provision (1): Current and Projected Employment in the Energy-Utility Sector

Overall, the stakeholder group noted the following about current and projected employment in the utility sector:

- The total number of utility jobs between 2016 and 2026 is not expected to change significantly.
- Utility jobs tend to be stable, but changes are starting to occur to accommodate the growing shift away from older, less efficient coal plants to newer, more efficient and cleaner generation, as well as consumer support for more local efforts utilizing renewable sources.
- The fastest growing energy occupations are in the wind and solar-energy industries. As more cities like Minneapolis adopt building performance rules, energy-efficiency employment could also grow.[5]
- A significant level of turnover of utility employees is expected over the period from 2016 through 2026, although feedback from utilities suggests that many positions related to power-generation operations may be eliminated through attrition of workforce employed at conventional power plants as they retire.

[4] Xcel Energy, in a presentation to the Electric Utility Workforce Group, August 26, 2019.
[5] The City of Minneapolis commissioned a workforce assessment with the National Association of State Energy Officials (NASEO) in 2019 to assess challenges and opportunities in the energy contractor fields. https://www.naseo.org/data/sites/1/documents/publications/Minneapolis%20Workforce%20Development%20Assessment.pdf

- Some of the state's large utilities indicate that they have already passed the "retirement cliff" and that new hires have significantly reduced the average age of employees, whereas other utilities continue to face a wave of retirements.

Despite clean-energy employers' optimism that Minneapolis energy-efficiency and renewable-energy employment will grow over the next year, finding and recruiting qualified workers in both energy efficiency and renewable energy presents a challenge to Minneapolis employers. The most cited reason for such difficulty is lack of experience, training, or technical skills. Competition, insufficient nontechnical skills (work ethic, dependability, critical thinking), and insufficient qualifications (certifications or education) are other major reasons why employers report hiring difficulty.

Given long-term changes in Minnesota's demographics, utilities will need to recruit new employees from an increasingly diverse workforce in order to continue providing safe, reliable energy service.

- Some EUDG members believe that Minnesota's utility sector has not fully tapped the potential workforce within diverse communities that have historically been underrepresented in utility and other areas of employment.
- Low high school graduation rates among some racial and ethnic minority communities present a challenge, and employers that establish relationships over time with students to encourage them to apply for utility jobs may have an advantage in attracting diverse candidate pools. The energy and utility sector can choose to become more involved in the high school system by supporting science, technology, engineering, and math (STEM) programs.
- The demographics applicable to each utility can vary significantly because they each serve a defined geography—for example, a utility filling positions in a rural territory will have demographics different from a utility filling positions in a metro area.
- Some utilities employ much of their workforce outside of Minnesota (because they have service territory and plants in other states) and are therefore subject to different sets of employment laws and regulations in those areas.

In identifying these points, the EUDG was provided with several different sources of workforce data, including the Minnesota Department of Employment and Economic Development (DEED), the Federal Bureau of Labor Statistics (BLS), and other state and federal sources. Detailed data for Minnesota's utility sector was obtained from the Center for Energy Workforce Development (CEWD).[6] Because the EUDG lacked the time and expertise to fully analyze these reports, the data are presented only as general base information.

Both DEED and CEWD report that the total number of jobs in the utility industry is expected to increase only slightly, if at all, between 2016 and 2026. As shown in Table 2 below, CEWD projects a minimal change in the total number of workers between 2016 and 2026, with only a net increase of 53 jobs, or

[6] CEWD is a nonprofit formed by electric and natural gas utilities to identify the need and develop the resources for "a diverse, qualified workforce with the knowledge, skills and ability to adapt and grow along with the [energy] industry." (For more information, see http://cewd.org/documents/CEWD-MemberSummary-Final.pdf.)

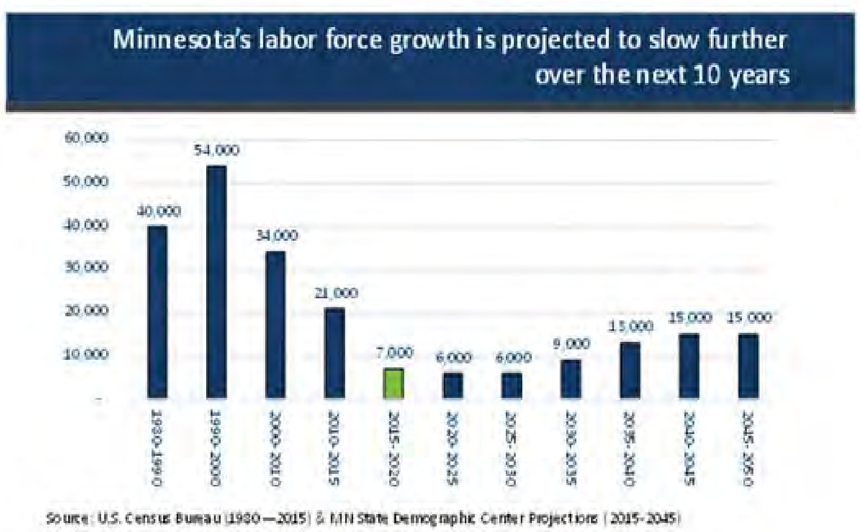
0.7% overall. However, as discussed in a subsequent section of this report, the utility industry is in the process of replacing about half of its workers, which presents both challenges and opportunities.

Table 2: Estimated Change in Total Jobs in Minnesota Utilities, 2016-2026[7]

Job Category	2016	2026	Change	% Change
Line workers	1,941	2,025	84	4.3%
Plant/Field Operators	1,065	1,034	–31	–2.9%
Technicians	1,837	1,821	–16	–0.9%
Engineers	1,077	1,107	30	2.8%
Total	5,920	5,987	67	1.1%
Total: All Occupations	7,757	7,810	53	0.7%

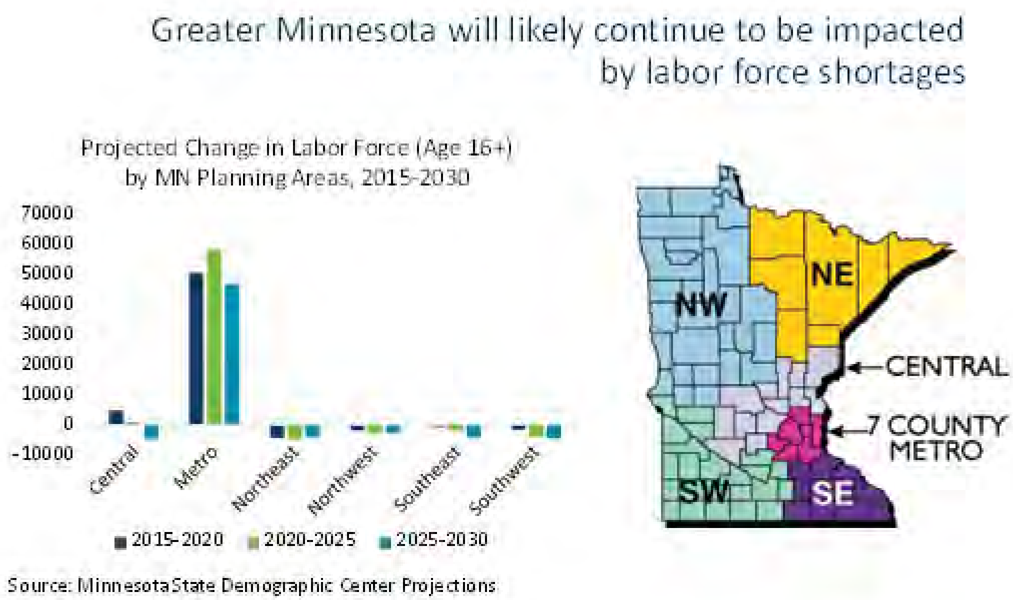
As shown in Figure 2, Minnesota's overall labor force growth is expected to slow over the next 10 years because of declining birth rates and out-migration of the domestic population combined with a slowing of immigrant population growth, according to Susan Brower, the Minnesota State Demographer. Further, as shown in Figure 3, this labor shortage is expected to have a larger impact in Greater Minnesota. Greater Minnesota utilities are already finding it a challenge to fill certain positions.

Figure 2: Labor Force Projections[8]



[7] Center for Energy Workforce Development
[8] Minnesota State Demographer

Figure 3: Regional Labor Impacts[9]



CEWD is also a resource for data, research, best practices, and workforce information specific to the utility industry. Some members of the EUDG are also members of the CEWD Minnesota consortia. CEWD's purpose is to bring energy companies, contractors, their associations, and energy educators together to attract and retain a diverse, qualified workforce with the knowledge, skills, and ability to adapt and grow along with the industry. Utilities noted that CEWD also has curricula for various levels of school to help students learn more about energy and build a knowledge base to participate in utility careers.

CEWD data provides a deeper look into key utility-job projections within the State of Minnesota. The key utility jobs recognized and surveyed by CEWD include line workers, plant/field operators, technicians, and engineers. Each key occupation includes sub-occupations. While the key categories of utility jobs such as line workers and plant operators have historically shaped this sector, there is a shift to needing more technician roles, roles supporting changes to the grid, and other technology-focused roles.

In planning for their own workforce needs, Xcel Energy recognizes that they need to recruit new workers with new skills not only because they need to fill future positions, but also because the technology is changing so rapidly along with customer expectations that there will be a need to retrain and reskill a portion of the existing workforce. Figure 4 indicates a significant shift in how Xcel Energy projects segments of their future workforce to change. Other members of the EUDG agreed.

For example, a line worker is one of many occupations within the energy and utility sector that is critical to ensuring the consistent, efficient, and safe transmission of energy to customers. Line workers are

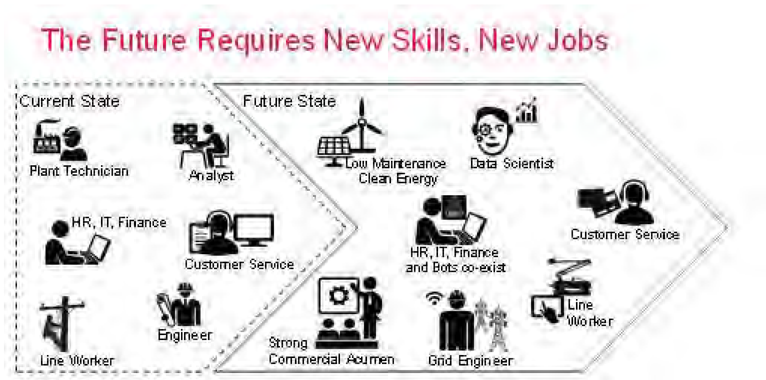
[9] Minnesota State Demographer

employed to assemble, repair, and maintain power-line infrastructure across Minnesota. Such work requires specialized training. To meet demand, electrical utilities have developed apprenticeship programs to develop a talent pipeline to train and retain highly skilled workers to perform line-worker responsibilities. These programs are registered with the Minnesota Department of Labor and Industry (DLI) to ensure they meet standards for quality and safety. DLI maintains information about the diversity of registered apprenticeship program participants. Table 3 shows the current demographics of the 483 Minnesota apprentices in the utilities industry.

Table 3: Statewide MN Registered Apprenticeship Diversity Numbers for Utility Industry[10]

	Total	Percentage
Total Line Workers	483	100.0%
Unspecified	132	27.3%
Hispanic	5	1.0%
American Indian	2	0.4%
Asian	14	2.9%
Black	10	2.1%
Other	10	2.1%
Female	15	3.1%
Veterans	37	7.7%

Figure 4: Xcel Energy Projected Job-Skill Changes[11]



The EUDG also discussed areas in which the energy utility sector may see growth or change. For example, members discussed potential growth in employment of electricians, HVAC technicians, engineers, and data scientists, as well as multilingual workers with cross-cultural competency.

[10] As reported to Minnesota Department of Labor and Industry.
[11] Xcel Energy, in a presentation to the Electric Utility Workforce Group, August 26, 2019.

Provision (2): Possible Approaches to Develop a Workforce that Has the Skills to Build, Maintain, and Operate the Electricity System of the Future

Opportunities to develop a diverse energy-utility workforce include the use of various strategies: research and planning, outreach and engagement, recruitment and hiring, and training and development.

Research & Planning

The Center for Energy and Workforce Development maintains the National Strategic Workforce Plan and other tools to help energy utilities attract, train, and hire from diverse demographic groups; this includes youth, veterans, women, and adults with a history of involvement in the criminal-justice system. The EUDG discussed the value of identifying and leveraging existing data and best practices as utility stakeholders develop or grow their workforce diversity efforts.

An important step in any strategic-planning process is data collection and analysis to inform the development of goals and objective setting. Currently, some energy utilities are required to complete and submit affirmative-action plans with the State of Minnesota Department of Human Rights based on Statute 363A.36 and Administrative Rules 5000.3400 to 5000.3600. These plans may provide a starting place for strategic planning. Utilities that are not required to submit affirmative-action plans may collect similar data for their own planning purposes.

Outreach & Engagement

EUDG members generally agreed that most Minnesotans know little about the industry, and the problem may be particularly acute in underrepresented communities, including low-income communities, immigrant communities, and communities of color. Those who work in underrepresented communities reported low levels of awareness, and energy utilities reported challenges in soliciting applications and proposals from a diverse pool of candidates and businesses.

Geography can also be a barrier to engaging potential candidates. While all utilities will seek new employees over time, concerns in Greater Minnesota deserve particular attention, as indicated by data from the State Demographer's Office. Utilities have described difficulties attracting employees to their region. One utility EUDG member from Greater Minnesota described the task as needing to recruit potential employees on three levels: to the industry first, then to the utility, then finally to the community. This can be a challenge in the future, given that population growth, including the growth of diverse communities, has been centered primarily in the Twin Cities metropolitan area as supported by Figure 3 above. Potential ways to recruit potential employees are discussed in the next section.

The low levels of awareness do not appear to be the result of a lack of effort on the part of utilities and other industry stakeholders to promote opportunities in their industries. Most of the utilities, labor unions, and trade associations that participated in the process indicated that their organizations have undertaken educational and outreach initiatives, including many that specifically target underrepresented groups and communities. At the same time, members recognized that current efforts are a patchwork: lacking broad coordination, unevenly resourced according to the capacity of each organization, underdeveloped connection with students in high school or younger, with limited opportunities to identify and disseminate best practices.

A successful effort to build a more diverse utility workforce could include coordinated campaigns to build awareness of the utility industry, especially within low-income communities, immigrant communities, and communities of color, with an emphasis on young people who are in the process of choosing educational and career paths. Such a campaign could draw lessons from existing initiatives that have made in-roads, including programs sponsored by utilities building trade unions, and community-based organizations, often in coordination with public schools. For example, the Minnesota Energy Consortium Steering Committee recently worked with the Minnesota Department of Education to add Energy as a category in the Career Wheel to encourage more students to consider careers in energy.

Participants suggested several specific ideas for building upon current efforts to coordinate and strengthen public education efforts with students in high school and perhaps younger, including establishing "energy experience centers" in underrepresented communities in order to expose youth and adults to energy technologies and technical educational opportunities, and to create hubs where interested individuals and businesses could connect with utilities, vendors, and training providers.

The EUDG discussed the importance of encouraging STEM curriculum for school-aged youths in order to ensure that Minnesota develops a diverse workforce with the education and technical skills needed to fill utility-industry positions. Community- and school-based programs, such as the Future Cities Competition, currently pair energy-utility professionals with students to provide STEM tutoring and career-pathways guidance.

Recruitment & Hiring

An approach that combines addressing barriers to hiring more diverse candidates, such as educational attainment and lack of access to transportation, and strategic recruitment and hiring techniques could increase utilities' ability to hire diverse candidates.

EUDG members identified employment barriers that could limit the success of efforts to hire more diverse candidates. The group sees a need to address these barriers to employment: education, transportation, and involvement in the criminal justice system.

Education

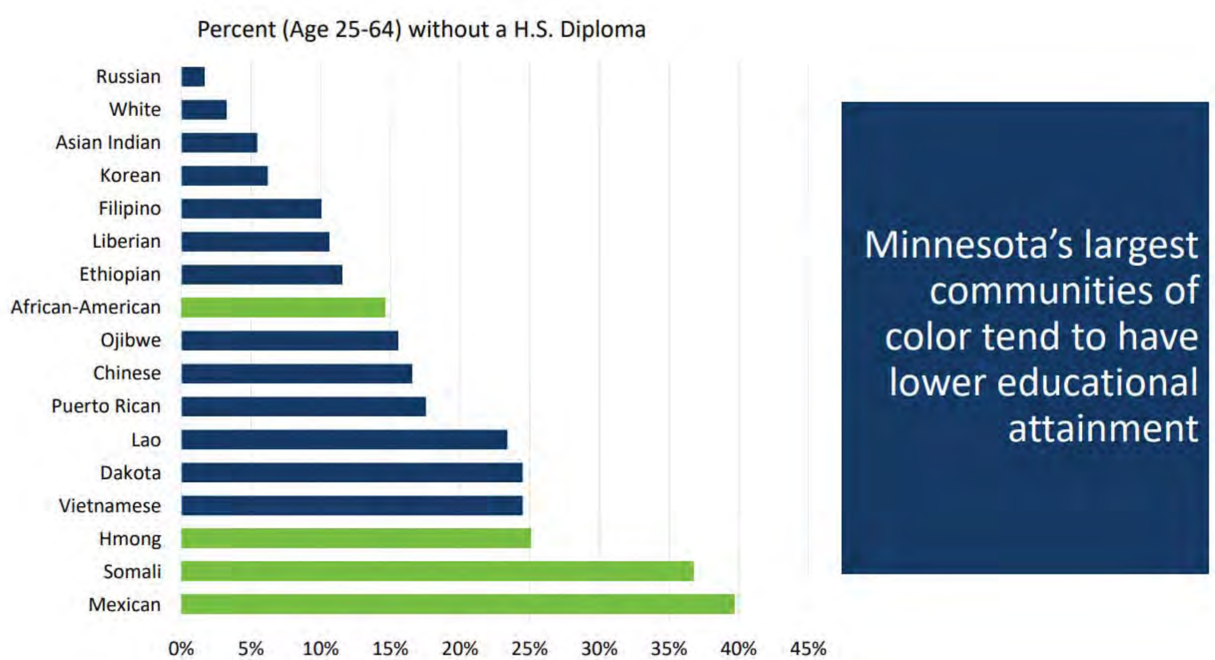
Minnesota has a great education system; however, it does not meet the full needs of members of minority communities. This negatively impacts the energy industry as it seeks to hire the best and brightest workers from diverse communities.

Minnesota energy utilities are challenged by the Minnesota's education crisis facing American Indian, Hispanic, Black, Hmong, and low-income White students. A report released on October 19, 2019, "Statewide Crisis: Minnesota's Education Achievement Gaps" by the Minnesota Federal Reserve, shows the serious challenge facing not just the energy industry, but all Minnesota industries.

The Minnesota Office of Higher Education issued its own report in 2016 entitled "Educating for the Future: Baseline Estimates of Educational Attainment." Again, this report also gives a wake-up call on the poor performance in preparing diverse students to achieve Minnesota standards set for graduation from institutions offering a community-college certificate and above. While the average achievement for all Minnesotans is 58%, the report shows a huge gap for different population groups. The highest is Asian at 63% achievement and the lowest is 21% for American Indian. It reports 24% for Hispanic, 35% for Black, and 50% for multiracial.

Figure 5 illustrates the statewide correlation of education and communities of color.

Figure 5: Education and Minnesota's Communities of Color[12]



Clearly, the energy utility sector is directly impacted by the quality and preparation of education for racial and ethnic minorities. And, there are some great best practices that help close the achievement gap such as the one being experienced by Minnesota.

[12] Minnesota State Demographer

A solution is clearly for the Minnesota educational system (K-12 to Ph.D.) to take a hard look at some national best practices and expand their presence in the state. Since this aspect applies to all of Minnesota and all economic industries, it makes sense to have the State lead an effort to substantially improve the education achievement of racial and ethnic minority students in its educational system.

Additionally, some EUDG members observed that the pool of jobs that is available to individuals without a high-school degree or General Educational Development (GED) is small.

Energy companies rely on Minnesota's public schools to deliver a well-prepared and diverse group of candidates, especially in STEM occupations. They rely on the State of Minnesota and school districts that serve diverse populations to make smart investments to close achievement gaps and improve retention and graduation rates for students of color and low-income and immigrant students.

Other Barriers to Employment

Lack of accessible training and transportation was also identified as a key barrier to employment. Investments in public transportation can play an important role in expanding access to employment or training. Without local training programs or transportation, students and other candidates may have limited access. It became clear in our conversations that there are positions in the construction trades and other technical occupations for which public transportation is not a viable option and that effort should be focused on ensuring that otherwise qualified candidates for construction or other technical careers are not excluded simply because they lack a valid driver's license or access to a vehicle. This is a particular challenge for employment on projects or in companies in Greater Minnesota.

While the utility sector would not be able to address these issues alone, solutions could begin with help from other sources to provide assistance in obtaining driver's licenses or helping to clear up legal issues that have caused an individual's license to be suspended. Beyond driver's licenses, potential applicants may need other assistance securing transportation, which could range from a caseworker helping individuals to develop transportation strategies using available resources, to subsidies or loans to help individuals secure vehicles or temporary transportation until he or she can afford a vehicle.

The group also discussed the need to ensure that individuals with past criminal-justice involvement are not being unnecessarily excluded from employment, recognizing important security considerations and legal requirements that energy utilities must meet.

Suggestions to Improve Recruitment

The EUDG suggested a number of possible tactics to recruit job candidates from diverse communities, including:

- Leveraging print, television/radio broadcasting, and online media outlets that target diverse populations to promote job postings;

- Using third-party contractors to ensure job postings reach a diverse pool of candidates via established networks of local career and community-based organizations that serve diverse populations;
- Participating in job fairs in diverse communities, such as at local military bases, community/technical schools, or designated Opportunity Zones;
- Support and partner with organizations that provide career-readiness assistance to under-represented populations; and
- Explore partnerships with organizations that work with immigrant and refugee populations to identify recruitment opportunities.

Partnering these approaches with strategic recruitment and hiring techniques could help energy utilities attract a more diverse workforce without sacrificing skill and expertise. Each utility will have a unique recruiting strategy based upon the differences in skill-set requirements and candidate options in the communities they serve.

Training & Development

Efforts to recruit and retain qualified candidates could include partnerships across industries and sectors, as well as paid internships and registered apprenticeship programs.

Building pipelines is an important strategy for energy utilities to attract and retain highly qualified and skilled employees. Some energy utilities have established partnerships with industry experts and academic institutions to identify and develop training programs. For example, one utility/industry model works by engaging diverse and local high school students—and their parents—with industry mentors in a long-term, holistic approach that focuses on helping them improve their job and education preparation and assisting them in leveraging existing community-support resources.

Some utilities offer paid internship and apprenticeship programs that help to identify and nurture professional skills among diverse youth groups. Both CenterPoint Energy and Xcel Energy have hosted AchieveMpls and Step Up high-school interns, representative of diverse communities in Minneapolis. Xcel Energy also participates in Right Track, another high school internship program.

The stakeholder group also highlighted the transition toward clean energy and new technologies as an opportunity to collaborate across sectors to train diverse populations. For example, information technology and data science offer opportunities for growth and change. Jobs to address these opportunities could come in the form of cybersecurity and electricians that install electric vehicle charging stations in homes and businesses.

Provision (3): Key trends that have shaped employment in this sector and the demographics of the sector, including the underrepresentation of women, veterans, and minorities in employment and leadership

EUDG did not collect employment data for the companies, and it is not able to report on the current state of affairs for the industry's workforce, or the underrepresentation of women, veterans, or minorities in general.

A quick review of the leadership of some of these energy organizations demonstrates very little inclusion of racial and ethnic minorities with few exceptions. Half of ALLETE's board of directors are women, which is an outstanding achievement.

Without data, it is impossible to assess the state of the upward mobility pipeline to examine and consider the challenges and opportunities.

Other Considerations

The Minnesota State Demographer's Office estimates the utility industry's 2018 job vacancy rate at 0.7%, as shown in Table 4, while the average rate for all industries' is 4.9%, which suggests that Minnesota's utilities offer positions that remain highly attractive even in periods of relatively high unemployment.

Table 4: Job Vacancies Minnesota, 2018 Q4[13]

Industry	No. of Job Vacancies	Job Vacancy Rate
Total, All Industries	136,917	4.9%
Agriculture, Forestry, Fishing & Hunting	1,266	5.5%
Mining	71	1.2%
Utilities	102	0.7%
Construction	5,691	4.6%
Manufacturing	12,972	4.0%
Wholesale Trade	3,835	3.2%
Retail Trade	20,890	6.9%
Transportation and Warehousing	6,026	5.6%
Information	1,043	2.0%
Finance and Insurance	4,211	3.1%
Real Estate and Rental and Leasing	1,707	5.0%
Professional and Technical Services	5,766	3.9%
Management of Companies and Enterprises	2,653	3.3%
Administrative and Waste Services	8,293	11.1%
Educational Services	6,452	2.6%
Health Care and Social Assistance	27,431	5.6%
Arts, Entertainment, and Recreation	2,555	5.3%
Accommodation and Food Services	18,479	8.1%
Other Services, EX: Public Admin	5,265	6.3%
Public Administration	2,208	1.7%

The State Demographer noted a direct correlation in education levels and unemployment gaps, and energy utilities have noted some similar trending with statewide workforce demographics. Utilities are managing significant changes in the role of their workforce as they shift from labor-intensive and geographically concentrated conventional power plants to more dispersed renewable generation that requires lower levels of operations and maintenance staffing.

Employment trends in this sector are the result of many factors:

- Education levels to skill sets (both historical and the future changing skills)
- Job opportunities
- Geographic location
- Domestic migration out of rural Minnesota
- Slowing international immigration

[13] Minnesota State Demographer

The industry employs a number of skilled labor or craft positions, such as line workers and plant workers, which may constitute the majority of workers in an organization. Because of the historical gender makeup of these positions, the industry as a whole has a predominantly male workforce.

As discussed in a previous section, the EUDG believes that not all communities have been aware of, or have known how to pursue, opportunities in the utility sector, which may have contributed to what are believed to be relatively low levels of participation by people of color, women, and other historically underrepresented groups. As the labor market tightens and our populations become more diverse, it is more important than ever to provide exposure of the energy industry to populations of workers who may not be aware of the opportunities that are available to them.

The lack of diversity in the educational pipeline must be considered. For example, Dakota County Technical College currently has the only accredited line-worker program in the Twin Cities metro area. The first four men of color to graduate from this program did so in the summer of 2019. This result happened because of concerted efforts to reach students who were on the margins. The hope for the future is that such results will become commonplace and no longer noteworthy. So, one recommendation would be to increase these types of programs to increase diversity in the line worker occupation.

The EUDG recognizes the need to inform and provide access to underrepresented populations regarding the education and training that is required to be qualified for a position in the industry. Exposure should start before potential workers are making decisions about post-secondary education along with direct exposure to positive role models in the industry. Role models can not only generate interest, but also serve as direct lines of contact to employers.

According to CEWD, the utility-industry workforce has changed significantly over the last decade and is benefiting from more than a decade of workforce initiatives to develop and hire workers into critical jobs. As industry hiring has increased and retirements have begun to stabilize, a younger and more diverse workforce is facing the need for a higher level of skills than ever before. This transformation will drive strategic change in everything from education to recruiting, hiring, and retention.

Although retirements have caused significant changes for the energy workforce in the past, CEWD's 2017 Gaps in the Energy Workforce Survey shows that nationally, about 12% of the workforce is ready to retire at any point, and overall retirements are forecast at a little over 2% a year for the next 10 years. That is below the percentage of employees who will leave for other reasons and validates the trend toward "normal" retirement rates for the industry.

According to CEWD, millennials make up almost 30% of the overall utility workforce and 40% of the engineering and line-worker positions. This younger workforce is driving an increase in nonretirement attrition, particularly among those with fewer than five years of service. Studies of millennials in the workplace indicate they are less hesitant to change jobs than their older counterparts. In an industry where it takes years to become fully competent in highly skilled jobs, and in a country where the current unemployment rate is below 4%, companies must rethink their employment value propositions in order to attract and retain new employees as well as effectively transfer the knowledge of those who leave.

Nationally, the energy workforce is also becoming increasingly diverse, reflecting an increased focus on diversity and inclusion efforts. For example, veterans now make up about 11% of survey respondents' current workforce, which is an increase from 8% in 2014. Similarly, racial and ethnic minorities now make up 26% of the workforce, up from 22%. However, the percentage of women in the utility workforce has shown only a slight increase from previous surveys and, at 24%, remains at half the levels of women's participation in the U.S. workforce.

Critical to this challenge is balancing workforce needs with reductions in labor budgets, as companies' internal and external cost pressures continue in the industry. External factors drive company priorities and, subsequently, their budgets. Each company must determine what it can afford in the way of workforce strategy.

Provision (4): Challenges to Replacing Retiring Workers

Table 5 below shows that CEWD projects a significant level of retirements along with expected attrition of employees for any reason (resignation, layoff, termination, etc.) in Minnesota utilities between 2016 and 2026 in these Key Occupation Employment areas:[14]

Table 5: Estimated Attrition and Retirements in Minnesota Utilities, 2016–2026[15]

Job Category	2016	2026	Change	Attrition and Retirements	% Attrition and Retirements
Line Workers	1,941	2,025	84	754	39%
Plant/Field Operators	1,065	1,034	–31	583	55%
Technicians	1,837	1,821	–16	1,057	58%
Engineers	1,077	1,107	30	522	48%
Subtotal	5,920	5,987	67	2,916	49%
Total: All Occupations	7,757	7,810	53	3,974	51%

There will be challenges in finding new workers, but there are also opportunities. For example, with the challenge of transferring knowledge and skills to new workers comes the opportunity of considering whether there are better ways to accomplish some tasks and using different skills of new workers. Further, as utilities promote jobs, more people may learn about the energy industry.

These anticipated retirements and attrition rates point towards a sense of urgency to develop a diverse group of workers with the skills needed for the 21st-century energy system.

[14] Does not include IT, accounting, or certain other employment categories.
[15] Center for Energy Workforce Development

Provision (5): Imbalance of Available Worker Skills to Utility Workforce Needs

Available data used

There are a variety of sources discussing employment in the energy industry. For purposes of this discussion, the EUDG has reviewed information from the following sources

- "The 2019 U.S Energy & Employment Report" by the National Association of State Energy Officials (NASEO) and Energy Futures Initiative (EFI)[16]
- The "Minnesota Energy Efficiency Workforce Gap Analysis" February 2019 report prepared by the Center for Energy and Environment (CEE)[17]
- The report "Transforming the Nation's Electricity System: The Second Installment of the QER, January 2017, Chapter V: The Electricity Workforce: Changing Needs, New Opportunities"[18]
- The Minnesota Department of Employment and Economic Development (DEED), which provides data for companies to use for Affirmative Action Plans required by Minnesota Statute 363A.36 using the latest available census data, in this case from 2010.[19]

These data sources illustrate common findings in the following areas, which are further detailed below:

- The necessary training needed to have qualified workers.
- The skills gap of the overall available workforce and demographics.

Training needed to have qualified workers

Each of the reports referenced in the previous section (Available Data Used) noted training and apprenticeships as a need for employment in energy utility jobs.

[16] This report explores in detail employment in the energy industry broken out into 5 energy sectors; fuel, electric power generation, transmission, distribution and storage, energy efficiency, and motor vehicles. It includes expected employment, difficulty hiring and demographics. The information in this report is mainly from the transmission, distribution and storage sector.
https://www.naseo.org/data/sites/1/documents/publications/USEER-2019-US-Energy-Employment-Report1.pdf

[17] This report focuses on careers in energy efficiency and looks at employment trends in this industry. It also includes data on the aging workforce and difficulties with hiring and diversity in the energy industry.
https://www.mncee.org/MNCEE/media/PDFs/MN-Energy-Efficiency-Workforce-Gap-3-1-19.pdf

[18] This report explores the employment in the energy industry, required training and skills, demographics in the industry, and reviews the challenges of recruiting and hiring new employees.
https://www.energy.gov/sites/prod/files/2017/01/f34/Chapter%205%20The%20Electricity%20Workforce%20Changing%20Needs,%20New%20Opportunities_0.pdf

[19] This data includes the labor-force availability by area in the state of Minnesota and by job. The labor-force availability looks at the entire labor force by job classification and the percentage of males/females and whites/minorities in that labor force. For this report, only jobs typically hired by energy utilities were included.
https://mn.gov/deed/data/data-tools/affirmative-action-statistics/

Each report references training. The drop in industry workforce-training programs in the 1980s, and the trend away from technical schools in the 1990s, are part of the skills-gap issue, and the CEE reports that "student retention remains an issue in training programs."

The EUDG discussed the importance of building a talent pipeline that begins when students are in high school or possibly earlier in their education. The EUDG also talked about the importance of expanding training opportunities for diverse populations. Without access to training, workers are less versatile. Apprenticeships may be one opportunity to shift from static training programs.

Skills gap and demographics

The reports discuss the lower number of women and minorities in the workforce compared with national averages. They highlight hiring difficulties resulting from skills gaps, such as lack of experience, training, or technical skills; the lack of access to STEM and other technical programs; and the lack of accessibility of utilities to a portion of the workforce.

> *Electricity and related industries employ fewer women and minorities than the national average, but have a higher proportion of veterans. Only 5 percent of the boards of utilities in the United States in 2015 include women, and approximately 13 percent of board members among the top 10 publicly owned utilities were African American or Latino. Underrepresentation in or lack of access to science, technology, engineering, and mathematics educational opportunities and programs contribute to the underrepresentation of minorities and women within the electricity industry.* (page 5-3 of the Energy.gov report)

This underrepresentation decreases the number of qualified workers, making these positions more difficult to hire.

Statistical data from the Minnesota Department of Employment and Economic Development (DEED) show the labor availability for the state of Minnesota, the Twin Cities area, and Greater Minnesota for jobs typically employed by energy utilities. Additional metropolitan statistical data is available from their website. One difference to note between these two statistical sources: DEED figures are based on the 2006–2010 American Community Survey and are therefore more than a decade old.

These data show that the percentage of underrepresented workers available in the workforce was fairly low, especially in technical areas such as construction and installation occupations, with overall availability of less than 10% for minorities and less than 3% for women. The figure dropped to less than 5% for people of color in greater Minnesota. The CEE report echoes the data shown in the DEED statistics and expresses concern at the lack of diversity in the energy-efficiency industry and notes that unions and apprenticeships offer training and access to the workforce pipeline. Current data from Minnesota's Department of Labor and Industry indicate that, as of July 2019, people of color accounted for 19% of registered apprentices, and women accounted for 7%. More than 90% of Minnesota's 12,000 registered apprentices work in construction and installation occupations. (See Employment and Economic Development Workforce Availability data in the Appendix.)

The information in the Appendix is not specific to utilities, so drawing conclusions for the utility industry from this information is difficult. Still, utilities are included in the data and the information is helpful to understand the context in which Minnesota utilities operate. For example, the information indicates that, for Minnesota as a whole, 10.36% of the labor force was classified as minority between 2006 and 2010, while only 6.5% of workers in management occupations and 6.75% of workers in construction and extraction occupations were minority workers. Women represented 43.01% of the labor force, but made up 34.56% of management occupations and only 2.98% of workers in construction and extraction occupations.

The information also confirms that there are differences in demographics across Minnesota. While the percentage of women is fairly consistent, there were fewer workers classified as minority in Greater Minnesota (5.0%) than in the Twin Cities (13.2%). This information helps support the conclusion that each utility will need to tailor individual recruitment strategies to successfully attain a diverse candidate pool for the positions they are posting.

Findings and recommendations

On the basis of the discussions detailed above, the EUDG identified the following findings and recommendations to increase workforce diversity. Long term, it is hoped that these efforts will strengthen and enhance economic development in the communities that utilities serve; providing employment opportunities helps to ensure the viability of those communities.

Findings

- Minnesota energy utilities are organized in three separate categories with unique geographic presence, governance, and demographics.
- The energy utility sector is changing, including a movement from large central-station power plants toward renewable and distributed energy resources. Utility customers' preferences for interactions with their energy provider have also changed (e.g., customers want more proactive service, quicker responses to outages and other needs). These developments require Minnesota's energy utilities to anticipate changes to the sector's workforce and procurement needs, as well. Given these factors, along with Minnesota's changing demographics, tapping diverse communities that have historically been underrepresented in utility and other areas of employment may be a means of addressing these needs.
- Though utilities have conducted outreach efforts, a lack of awareness about the industry, particularly within underrepresented communities, can pose a challenge to recruitment efforts.
- A number of employment barriers may limit the success of efforts to hire more diverse candidates: job awareness, education/training, transportation, and criminal-justice system involvement.
- Existing cross-sector partnerships between utilities and industry experts, academic institutions, and others provide a model for training and development of diverse populations.
- Shifts in technology are expected to create an increase in technician roles, roles supporting changes to the grid, and other technology and data-focused roles. Therefore, the lack of diversity in the education pipeline for those educational programs that would support those

emerging roles (i.e., STEM, information technology, skilled field technician, and data and analytics) must also be considered.

- CEWD's projection of retirements and expected attrition can pose a challenge but also offers opportunities for utilities to seek new workers from diverse populations. However, utilities will need to balance the need to fill positions along with the need to retrain and reskill the current workforce in the changing environment.
- The drop in industry workforce-training programs in the 1980s, and the trend away from technical schools in the 1990s, have contributed to a skills-gap issue. This gap is particularly acute in diverse communities, where additional training is needed to build up the talent pipeline. Elements that may contribute to the gap include lack of experience, training, or technical skills and lack of access to STEM and other technical programs.

Recommendations

- **Data collection:** Collecting data allows utilities to know where they currently sit as well as informing their goals for the future. The requirements for some utilities to file affirmative-action plans and employment-demographics information with the State helps ensure that energy utilities are making good-faith efforts to employ a diverse workforce. It is recommended that these utilities continue to use these affirmative-action plans as a starting place for strategic planning. For utilities that are not required to file demographic information with the State, the affirmative-action reporting templates and guidelines could voluntarily be used to help utilities track demographics information in a consistent way with the reporting utilities.
- **Build on current efforts in engagement, building pipelines, training and hiring practices**: Energy utilities should continue their existing recruitment, training, retention (including professional development, cultural competency, and skill development), and outreach programs and allocate resources for programs to cultivate diversity at all levels.
    - **Emphasize ongoing efforts**: Rather than one-time engagement efforts, there must be an ongoing dialogue between industry stakeholders, educational entities, and the communities they serve. There may be skills gaps where the potential workforce is not engaged.
    - **Build pipelines**: Career exposure should start during high school or earlier for students and young people, and employers should establish and maintain relationships with targeted schools and populations and engage consistently and regularly with students over time. This includes educating young people on the energy industry as well as providing tools and programs to gain fundamental knowledge of the industry. Establish programs in middle and high schools where students can explore and learn about the industry and guide students into the postsecondary programs that will provide the education they need to obtain employment in the industry. This should be done while continually tracking and maintaining contact with these young people through industry mentors or other contacts.
    - **Expand training**: It is important to expand training opportunities for diverse populations, including registered apprenticeships, paid internships, and paid

fellowships, to help identify and nurture professional skills. Utilities may choose to support the efforts of MN Energy Center of Excellence or other programs to include Energy Systems on the “career wheel” that schools use to discuss careers with students.

  - **Analysis of hiring requirements and reducing barriers**: Energy utilities should review their existing recruitment and hiring practices to ensure that job-entry requirements are appropriately aligned with the actual requirements of the job. Special attention should be paid to acknowledging and removing existing barriers. For example, if it is found that otherwise qualified candidates are excluded for construction or other technical careers because they lack a valid driver’s license or access to a vehicle, utilities should consider alternative solutions to engage those candidates.
- **Partner with other utilities:** Recognizing that different utilities have different levels of resources and staff capacity, some utilities might work jointly with other utilities to allocate resources and funding to explore innovative outreach and awareness models, including:
  - **New methods of reaching particular diverse groups through existing energy services:**. For example, utilities might integrate information about career opportunities into the provision of their services, such as energy-efficiency upgrades in underrepresented communities
  - **Coordinated and targeted marketing campaigns to build awareness of the utility industry**, especially within low-income communities, immigrant communities, and communities of color, with an emphasis on young people who are in the process of choosing educational and career paths
  - **Establishing “energy-experience centers” located in accessible locations**, including Opportunity Zones, within underrepresented communities in order to ensure access and expose youth and adults to energy technologies and educational opportunities, and to create hubs where interested individuals and businesses could connect with utilities, vendors, and training providers
  - **Expanding and/or replicating community and school-based programs that support STEM learning**, such as the CEWD school curriculum or mentoring programs such as the Future Cities Competition, which pairs energy-utility professionals with students to provide STEM tutoring and career-pathways guidance. There has been a re-emergence of technical education programs at the high school level. Some high schools are developing their own career and education facilities. Utilities can further support STEM education by engaging with these facilities.
- **Investment from the State:** Solutions are unlikely to come from the energy utility sector alone.
  - It is important for the State of Minnesota and school districts serving diverse populations to invest in closing achievement and opportunity gaps and improving retention and graduation rates for racial and ethnic minority students in low-income/underresourced households, and students from immigrant populations.
  - **Addressing transportation barriers** will also need assistance from entities outside the utility sector to help ensure that potential employees have reasonable access to training and jobs.

- **Recognize positive impact of utility ownership:** The impact of diversity efforts in the regulated electric-utility sector may be greatest where generation and transmission assets are owned by utilities, because third-party owners are not currently held to the same equity and transparency standards. Minnesota's agencies, boards, and commissions are encouraged to recognize and weigh the impact of utility ownership on diversity where consistent with their legal authority. The legislature should also consider taking steps to ensure that independent power producers and other beneficiaries of ratepayer-funded subsidies for distributed-generation and energy-efficiency programs, including Community Solar Gardens, be required to meet the same standards as regulated utilities.
- **Partner with nonutilities**: Energy utilities should explore partnering with industry partners, building trade unions, academic institutions, community-based organizations, and workforce agencies to identify and develop career pipelines, while making the training and employment opportunities more accessible to underrepresented populations.
- **Continue this process**: The EUDG can continue their work to gather many stakeholders to discuss challenges, successes, resources, and best practices with regard to increasing workforce diversity.

Supplier Diversity

Provision (6): Challenges and possible approaches to increasing supplier diversity

Per the Session Law, the scope of supplier diversity portion of this report is limited to one charge: identify the challenges and possible approaches to increasing supplier diversity.

EUDG Definition of Supplier Diversity

For the context of this report, EUDG participants defined "Diverse Suppliers" to include the following types of businesses:

- Minority-Owned Businesses: A business at least 51% owned and controlled by a minority group member(s) of one of the following ethnicities: African American, Asian-Indian American, Asian-Pacific American, Hispanic American, Native American
- Women-Owned Businesses: A business at least 51% owned and controlled by one or more women
- Veteran-Owned Businesses: A business at least 51% owned and controlled by one or more veterans or service-disabled veterans
- LGBT-Owned Businesses: A business that is at least 51% owned and controlled by one or more LGBT individuals

- Small Economically Disadvantaged Businesses: A small business that is at least 51% owned and controlled by one or more individuals who are both socially and economically disadvantaged; for a publicly owned business, at least 51% of its stock must be owned by one or more individuals of the following ethnicities: African Americans, Hispanic Americans, Asian-Pacific American, Subcontinent Asian Americans and Native Americans.
- HUBZone Businesses: As defined by the Small Business Administration, a small business that (a) is located in a historically underutilized business zone; (b) is owned, controlled, and operated by one or more U.S. citizens; and (c) for which at least 35% of its employees reside in a HUBZone
- Disability-Owned Enterprises: A for-profit business that is at least 51% owned, managed, and controlled by a person with a disability, regardless of whether or not that business owner employs person(s) with a disability.

Utilities that have existing supplier diversity programs track the spending in two ways: (1) money that is paid directly to Diverse Suppliers (Tier I spend); and (2) money that is paid to a prime contractor who then pays a subcontractor who is a Diverse Supplier (Tier II spend). A prime contractor is defined as a supplier that is awarded a direct contract from a utility.

Utilities can utilize numerous methods to identify Diverse Suppliers, including obtaining supplier information through the following sources:

- National Minority Supplier Development Council and Regional Affiliates
- Women's Business Enterprise National Council and Regional Affiliates
- National Veteran's Business Development Council
- National LGBT Chamber of Commerce
- Federal government registration sites such as SAM.GOV
- Ethnic Chambers of Commerce

Background

As indicated previously, there are multiple types of utility providers ("utilities") in the State of Minnesota, including investor-owned, cooperatives, and municipal and rural electric associations. Among these, there are significant differences in size and the geographic location of customers served. Three providers have established supplier-diversity programs; most utilities do not because they don't have enough resources/personnel to start or manage such programs. Most of the utilities, however, do place a great emphasis on buying from suppliers that are located within their respective service territories. All the utilities recognize the importance of having their supplier base reflect the communities they serve.

Participation among the utilities (investor owned, municipal, cooperatives) should be voluntary.

Findings and recommendations

On the basis of the discussions detailed above, the EUDG identified the following findings and recommendations to increase supplier diversity:

Findings: Challenges to the Utilities

Following are challenges identified by the EUDG that utilities address in their efforts to increase supplier diversity:

- Supplier programs need to be as "diverse" as the communities the utility serves; therefore, the desire to buy local or purchase from the investor owned/cooperative/municipal customer base is as important as increasing opportunities for new suppliers who hold diversity certification(s).
- Creating supplier diversity programs for most utilities presents a challenge given the lack of budget, tracking software, and employee resources. Smaller utilities may not be able to justify the addition of staff and needed resources to develop a program in the same manner as the largest utilities. Ultimately, utilities could seek to recover costs incurred to launch and manage a program from rate payers.
- Considering that many utilities do not currently track diverse supplier spend, there is no baseline for these utilities to start from and compare to. Baselines for each utility for increasing opportunities for diverse suppliers should be determined in the initial year(s) before thresholds and goals to increase opportunities can be set for future years.
- Many utilities have limited outreach resources to identify diverse suppliers (see Workforce Diversity section).
- Large amounts of diverse supplier spend are specifically project driven (wind/solar additions), and once projects are completed, it's hard to immediately replace that same level of spending.
- A utility may increase bid opportunities for diverse suppliers (when possible and when identifiable); however, corporate or board policy may require the utility to award to the lowest bidder, which will impact whether the utility is able to increase spending. The goals should be based on opportunities to bid and not mandated spending. The diverse contractor must also be compliant with the utility's internal requirements—such as safety, insurance, and warranty.
- Past purchasing decisions often dictate future purchasing decisions for a utility, where the utility is tied to the previous vendor because of proprietary design or equipment standardization.

Findings: Challenges to Diverse Suppliers

Diverse suppliers, in turn, address their own challenges to meet utilities' needs.

- Newly established diverse suppliers who have diversity certification(s) are often unable to meet the scale and scope needs for large utilities and need to identify Tier II opportunities with prime contractors in order to gain experience and grow their business.
- Some diverse suppliers may have limited access to capital or outside funding, while others are very large and are not limited in these respects.
- Solicitations are not publicized broadly in diverse communities.

- There is a lack of training or helplines available to explain the process to businesses who are new to the industry or the procurement process.
- There is a lack of encouragement for young, diverse individuals to expose them to the idea of creating their own businesses

Recommendations

Utilities can use a number of strategies to increase supplier diversity:

Work in partnership. Utilities can work in partnership with other entities:

- Those utilities in the state that have existing Supplier Diversity programs can share their list of diverse suppliers with other utilities across state.
- They can work jointly to engage with diverse suppliers and share best practices.
- Community groups can also serve as partners by offering ideas or activities that results in enhanced supplier diversity outcomes.
- Additionally, utilities can solicit information from existing prime contractors on the subcontractors that are used and identify diverse suppliers in process.
- Finally, utilities can ask utility credit-card providers to identify diverse suppliers from which they are obtaining goods/services currently.

Appendix A: Workforce Availability

The Minnesota Department of Employment and Economic Development (DEED) provides data for the labor force availability by area in the state of Minnesota and by job. The most recent available DEED statistics for Minnesota, which covers 2006–2010, show that the percentage of underrepresented workers available in the workforce was fairly low, especially in technical areas such as construction and installation occupations, with overall availability of less than 10% for minorities and less than 3% for women. This information includes, but is not specific to, utilities.[20]

Minnesota Department of Employment and Economic Development Workforce Availability Data

	Minnesota						
COC	Occupation	SOC	Labor Force	Percent of Total Labor Force			
				Male	Female	White	Minority
001-992	**Total Civilian Labor Force**		**988,762**	**56.99%**	**43.01%**	**89.64%**	**10.36%**
001-043	Management Occupations	11-0000	134,148	65.44%	34.56%	93.50%	6.50%
050-095	Business and Financial Operations Occupations	13-0000	110,915	42.81%	57.19%	90.82%	9.18%
100-124	Computer and Mathematical Occupations	15-0000	77,964	73.55%	26.45%	82.62%	17.38%
130-156	Architecture and Engineering Occupations	17-0000	30,261	86.45%	13.55%	90.07%	9.93%
160-196	Life, Physical, and Social Sciences Occupations	19-0000	195	74.36%	25.64%	100.00%	0.00%
260-292	Arts, Design, Entertainment, Sports, and Media Occupations	27-0000	6,865	41.39%	58.61%	96.09%	3.91%
370-395	Protective Services Occupations	33-0000	11,830	79.31%	20.69%	76.52%	23.48%
420-425	Building and Grounds Cleaning and Maintenance Operations	37-0000	55,075	70.57%	29.43%	77.23%	22.77%
470-496	Sales and Related Occupations	41-0000	28,317	66.71%	33.29%	94.59%	5.41%
500-593	Office and Administrative Support Occupations	43-0000	323,299	23.42%	76.58%	89.74%	10.26%
620-694	Construction and Extraction Occupations	47-0000	57,401	97.02%	2.98%	93.25%	6.75%
700-762	Installation, Maintenance, and Repair Occupations	49-0000	55,801	97.21%	2.79%	92.72%	7.28%
770-896	Production Occupations	51-0000	25,340	81.67%	18.33%	90.83%	9.17%
900-975	Transportation and Material Moving Occupations	53-0000	71,351	95.68%	4.32%	90.95%	9.05%

	Minneapolis - St. Paul Metropolitan Statistical Area						
COC	Occupation	SOC	Labor Force	Percent of Total Labor Force			
				Male	Female	White	Minority
001-992	**Total Civilian Labor Force**		**647,835**	**56.6%**	**43.4%**	**86.8%**	**13.2%**
001-043	Management Occupations	11-0000	100,390	64.7%	35.3%	92.4%	7.6%
050-095	Business and Financial Operations Occupations	13-0000	86,055	43.9%	56.1%	89.5%	10.5%
100-124	Computer and Mathematical Occupations	15-0000	63,805	74.2%	25.8%	80.6%	19.4%
130-156	Architecture and Engineering Occupations	17-0000	20,755	86.5%	13.5%	88.0%	12.0%
160-196	Life, Physical, and Social Sciences Occupations	19-0000	75	60.0%	40.0%	100.0%	0.0%
260-292	Arts, Design, Entertainment, Sports, and Media Occupations	27-0000	5,435	41.1%	58.9%	95.2%	4.8%
370-395	Protective Services Occupations	33-0000	7,610	81.5%	18.5%	72.9%	27.1%
420-425	Building and Grounds Cleaning and Maintenance Operations	37-0000	29,950	71.8%	28.2%	66.0%	34.0%
470-496	Sales and Related Occupations	41-0000	20,270	65.1%	34.9%	93.1%	6.9%
500-593	Office and Administrative Support Occupations	43-0000	204,075	25.4%	74.6%	86.4%	13.6%
620-694	Construction and Extraction Occupations	47-0000	30,665	96.5%	3.5%	91.3%	8.7%
700-762	Installation, Maintenance, and Repair Occupations	49-0000	29,840	96.8%	3.2%	89.3%	10.7%
770-896	Production Occupations	51-0000	13,490	82.2%	17.8%	87.2%	12.8%
900-975	Transportation and Material Moving Occupations	53-0000	35,420	96.0%	4.0%	87.5%	12.5%

[20] https://mn.gov/deed/data/data-tools/affirmative-action-statistics/

Duluth-Superior Metropolitan Statistical Area

COC	Occupation	SOC	Labor Force	Percent of Total Labor Force Male	Female	White	Minority
001-992	**Total Civilian Labor Force**		**38,294**	**56.28%**	**43.72%**	**95.14%**	**4.86%**
001-043	Management Occupations	11-0000	4,235	68.60%	31.40%	93.86%	6.14%
050-095	Business and Financial Operations Occupations	13-0000	3,470	43.05%	56.95%	97.41%	2.59%
100-124	Computer and Mathematical Occupations	15-0000	1,305	75.40%	24.60%	93.10%	6.90%
130-156	Architecture and Engineering Occupations	17-0000	1,050	82.38%	17.62%	98.10%	1.90%
160-196	Life, Physical, and Social Sciences Occupations	19-0000	50	60.00%	40.00%	100.00%	0.00%
260-292	Arts, Design, Entertainment, Sports, and Media Occupations	27-0000	155	41.93%	58.07%	100.00%	0.00%
370-395	Protective Services Occupations	33-0000	645	77.52%	22.48%	88.37%	11.63%
420-425	Building and Grounds Cleaning and Maintenance Operations	37-0000	3,030	73.76%	26.24%	92.74%	7.26%
470-496	Sales and Related Occupations	41-0000	1,179	63.95%	36.05%	99.15%	0.85%
500-593	Office and Administrative Support Occupations	43-0000	14,399	22.99%	77.01%	94.65%	5.35%
620-694	Construction and Extraction Occupations	47-0000	748	95.99%	4.01%	95.99%	4.01%
700-762	Installation, Maintenance, and Repair Occupations	49-0000	3,808	97.11%	2.89%	98.29%	1.71%
770-896	Production Occupations	51-0000	740	90.54%	9.46%	95.95%	4.05%
900-975	Transportation and Material Moving Occupations	53-0000	3,480	95.54%	4.46%	94.26%	5.74%

Mankato Metropolitan Statistical Area

COC	Occupation	SOC	Labor Force	Percent of Total Labor Force Male	Female	White	Minority
001-992	**Total Civilian Labor Force**		**17,442**	**54.45%**	**45.55%**	**95.16%**	**4.84%**
001-043	Management Occupations	11-0000	1,878	61.40%	38.60%	97.34%	2.66%
050-095	Business and Financial Operations Occupations	13-0000	1,299	42.19%	57.81%	95.38%	4.62%
100-124	Computer and Mathematical Occupations	15-0000	905	64.09%	35.91%	92.82%	7.18%
130-156	Architecture and Engineering Occupations	17-0000	415	93.97%	6.03%	98.79%	1.21%
160-196	Life, Physical, and Social Sciences Occupations	19-0000	0	0.00%	0.00%	0.00%	0.00%
260-292	Arts, Design, Entertainment, Sports, and Media Occupations	27-0000	185	45.94%	54.06%	100.00%	0.00%
370-395	Protective Services Occupations	33-0000	510	81.37%	18.63%	91.18%	8.82%
420-425	Building and Grounds Cleaning and Maintenance Operations	37-0000	930	66.67%	33.33%	91.94%	8.06%
470-496	Sales and Related Occupations	41-0000	335	73.13%	26.87%	98.51%	1.49%
500-593	Office and Administrative Support Occupations	43-0000	6,668	22.06%	77.94%	94.68%	5.32%
620-694	Construction and Extraction Occupations	47-0000	1,132	97.79%	2.21%	95.14%	4.86%
700-762	Installation, Maintenance, and Repair Occupations	49-0000	1,153	95.14%	4.86%	97.40%	2.60%
770-896	Production Occupations	51-0000	708	76.70%	23.30%	93.64%	6.36%
900-975	Transportation and Material Moving Occupations	53-0000	1,324	93.96%	6.04%	95.84%	4.16%

Rochester Metropolitan Statistical Area

COC	Occupation	SOC	Labor Force	Percent of Total Labor Force Male	Female	White	Minority
001-992	**Total Civilian Labor Force**		**33,482**	**57.21%**	**42.79%**	**92.89%**	**7.11%**
001-043	Management Occupations	11-0000	3,054	64.64%	35.36%	95.74%	4.26%
050-095	Business and Financial Operations Occupations	13-0000	2,725	47.67%	52.33%	90.82%	9.18%
100-124	Computer and Mathematical Occupations	15-0000	4,085	75.76%	24.24%	86.66%	13.34%
130-156	Architecture and Engineering Occupations	17-0000	1,484	90.23%	9.77%	86.52%	13.48%
160-196	Life, Physical, and Social Sciences Occupations	19-0000	15	100.00%	0.00%	100.00%	0.00%
260-292	Arts, Design, Entertainment, Sports, and Media Occupations	27-0000	335	38.81%	61.19%	100.00%	0.00%
370-395	Protective Services Occupations	33-0000	290	82.76%	17.24%	65.52%	34.48%
420-425	Building and Grounds Cleaning and Maintenance Operations	37-0000	2,130	77.47%	22.53%	86.39%	13.61%
470-496	Sales and Related Occupations	41-0000	530	77.36%	22.64%	96.22%	3.78%
500-593	Office and Administrative Support Occupations	43-0000	11,740	19.16%	80.84%	96.59%	3.41%
620-694	Construction and Extraction Occupations	47-0000	2,148	98.37%	1.63%	96.98%	3.02%
700-762	Installation, Maintenance, and Repair Occupations	49-0000	1,912	97.38%	2.62%	93.20%	6.80%
770-896	Production Occupations	51-0000	654	85.47%	14.53%	100.00%	0.00%
900-975	Transportation and Material Moving Occupations	53-0000	2,380	93.28%	6.72%	89.49%	10.51%

	Greater Minnesota (Excludes all counties in metropolitan statistical areas)						
COC	Occupation	SOC	Labor Force	Percent of Total Labor Force			
				Male	Female	White	Minority
001-992	**Total Civilian Labor Force**		**218,113**	**58.6%**	**41.4%**	**95.0%**	**5.0%**
001-043	Management Occupations	11-0000	21,157	68.6%	31.4%	97.0%	3.0%
050-095	Business and Financial Operations Occupations	13-0000	15,067	36.8%	63.2%	95.4%	4.6%
100-124	Computer and Mathematical Occupations	15-0000	6,361	68.8%	31.2%	94.0%	6.0%
130-156	Architecture and Engineering Occupations	17-0000	5,788	85.0%	15.0%	96.0%	4.0%
160-196	Life, Physical, and Social Sciences Occupations	19-0000	51	100.0%	0.0%	100.0%	0.0%
260-292	Arts, Design, Entertainment, Sports, and Media Occupations	27-0000	695	44.2%	55.8%	98.6%	1.4%
370-395	Protective Services Occupations	33-0000	2,330	73.4%	26.6%	79.6%	20.4%
420-425	Building and Grounds Cleaning and Maintenance Operations	37-0000	16,910	68.1%	31.9%	89.9%	10.1%
470-496	Sales and Related Occupations	41-0000	5,189	71.1%	28.9%	98.2%	1.8%
500-593	Office and Administrative Support Occupations	43-0000	73,862	19.1%	80.9%	95.4%	4.6%
620-694	Construction and Extraction Occupations	47-0000	20,258	97.7%	2.3%	95.3%	4.7%
700-762	Installation, Maintenance, and Repair Occupations	49-0000	16,644	98.2%	1.8%	97.0%	3.0%
770-896	Production Occupations	51-0000	8,579	79.91%	20.09%	94.56%	5.44%
900-975	Transportation and Material Moving Occupations	53-0000	25,222	95.8%	4.2%	94.3%	5.7%

Appendix B: Stakeholder Participants

The following stakeholders participated in at least one meeting that discussed the report content. Participants who attended the kick-off meeting only are not listed. Leadership roles are listed first, followed by participants in alphabetical order.

José Pérez, Hispanics In Energy (Chair, EUDG)
Anita Grace, GRACE Multicultural (Co-Vice Chair, EUDG)
Jennifer Peterson, Minnesota Power (Co-Vice Chair, EUDG)

Ben Passer, Fresh Energy (Chair, EUDG Workforce Diversity Subcommittee)
Jamez Staples, Renewable Energy Partners (Co-Vice Chair, EUDG Workforce Diversity Subcommittee)
Michelle Dreier, Electrical Association (Co-Vice Chair, EUDG Workforce Diversity Subcommittee)
MJ Horner, Xcel Energy (Co-Vice Chair, EUDG Workforce Diversity Subcommittee)

John Pacheco, Latino Chamber (Chair, EUDG Supplier Diversity Subcommittee)
Jim Garness, Xcel Energy (Vice Chair, EUDG Supplier Diversity Subcommittee)

Adam Tromblay, Nobles Cooperative Electric
Akisha Everett, University of Minnesota Energy Transition Lab
Amber Lee, CenterPoint Energy
Amy Decaigny, ALLETE
Ana Vang, Minnesota Power
Andy Morris, Council of Asian Pacific Minnesotans
Anne Hunt, Office of Enterprise Sustainability MN Department of Administration
Basil Ajuo, Minnesota Africans United
Betty Jo Kiesow, Dakota Electric Association
Bill Black, Minnesota Municipal Utilities Association
Brady Steigauf, Center for Energy and Environment
Bree Halverson, Blue Green Alliance
Brian Meloy , Stinson LLP
Brian Winkelaar, International Brotherhood of Electrical Workers
Bridget Dockter, Xcel Energy
Bruce Gerhardson, Otter Tail Power
Bryan Glines, CenterPoint Energy
Cecilia Lettner, Xcel Energy
Chris Anderson, Minnesota Power
Cindy Schue, Great River Energy
Corey Hintz, Dakota Electric
Cynthia Radtke, North Central Minority Supplier Diversity Council
Emma Schoppe, CenterPoint Energy
Erica Larson, CenterPoint Energy
Felipe Illescas, MN Council on Latino Affairs
George Watson, Mattson Consulting

Grania Mckiernan, Xcel Energy
Greg Rausch, Otter Tail Power
Heather Olson, North Central Minority Supplier Diversity Council
Heather Westra, Prairie Island Indian Community
Henry Torres, Value of Five
Jenny Glumack, Midwest Renewable Energy Association
Jessica Fyhrie, Otter Tail Power
Jessica Looman, MN State Building and Construction Trades Council
John Aiken, MN Department of Labor
Jose Nino, Hispanics In Energy
Kate O'Connell, MN Department of Commerce *(The Minnesota Department of Commerce played a supportive role in helping to clarify regulatory issues and other tasks, but does not take a position at this time on any specific recommendations in the report.)*
Kent Sulem, Minnesota Municipal Utilities Association
Kevin Pranis, Laborers' International Union of North America, MN & ND
Kimberly Dunning, CenterPoint Energy
Laura Krollman, ALLETE
Leslie Philmon, MN Department of Labor and Industry
Lisa Orpen, Great River Energy
Liz Lucente, MN Solar Energy Industries Association
Machy Vu, HOPE Community Academy
Mariesa Sun-Saenz, US Cuba Artist Exchange
Markeeta Keyes, City of Minneapolis
Maychy Vu, HOPE Community Academy
Melissa Stachovich, MN Rural Electric Association
Michael Birchard, Inver Hills Community College & Dakota County Technical College
Monica Villasenor, SHPE
Nakhia Morrissette, Solar Energy Industries Association
Paula Mastel, Great River Energy
PaZong Thao, MN Department of Administration
Raj Rajan, University of Minnesota Institute on the Environment
Riley Conlin, Stoel Rires LLP
Rob Scott-Hovland, Missouri River Energy Services
Rosa Tock, Minnesota Council on Latino Affairs
Rose Patzer, Minnesota State Energy Center of Excellence
Sarah Arnold, Women's Business Development Center
Stephanie Herrera, SAH & Associates
Steve Downer, Minnesota Municipal Utilities Association
Susanne Straus, Minnkota Power Cooperative
Syd Briggs, Steele-Waseca Co-op Electric
Thomas Herr, Hmong Village
Wayne Dupuis, Fond du Lac Band of Lake Superior Chippewa

CERTIFICATE OF SERVICE

I, Lynnette Sweet, hereby certify that I have this day served copies of the foregoing document on the attached list of persons.

xx by depositing a true and correct copy thereof, properly enveloped with postage paid in the United States mail at Minneapolis, Minnesota

xx electronic filing

Docket No. E002/CI-17-401

Dated this 30th day of April 2021

/s/

Lynnette Sweet
Regulatory Administrator

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Michael J.	Bull	mbull@mncee.org	Center for Energy and Environment	212 Third Ave N Ste 560 Minneapolis, MN 55401	Electronic Service	No	OFF_SL_17-401_Official
Generic Notice	Commerce Attorneys	commerce.attorneys@ag.state.mn.us	Office of the Attorney General-DOC	445 Minnesota Street Suite 1400 St. Paul, MN 55101	Electronic Service	Yes	OFF_SL_17-401_Official
David	Dahlberg	davedahlberg@nweco.com	Northwestern Wisconsin Electric Company	P.O. Box 9 104 South Pine Street Grantsburg, WI 548400009	Electronic Service	No	OFF_SL_17-401_Official
John	Farrell	jfarrell@ilsr.org	Institute for Local Self-Reliance	2720 E. 22nd St Institute for Local Self-Reliance Minneapolis, MN 55406	Electronic Service	No	OFF_SL_17-401_Official
Sharon	Ferguson	sharon.ferguson@state.mn.us	Department of Commerce	85 7th Place E Ste 280 Saint Paul, MN 551012198	Electronic Service	No	OFF_SL_17-401_Official
Katherine	Hamilton	katherine@aem-alliance.org	Advanced Energy Management Alliance	1701 Rhode Island Ave, NW Washington, DC 20036	Electronic Service	No	OFF_SL_17-401_Official
Annie	Levenson Falk	annielf@cubminnesota.org	Citizens Utility Board of Minnesota	332 Minnesota Street, Suite W1360 St. Paul, MN 55101	Electronic Service	No	OFF_SL_17-401_Official
Gregory C.	Miller	gmiller@dakotaelectric.com	Dakota Electric Association	4300 220th Street West Farmington, MN 55024	Electronic Service	No	OFF_SL_17-401_Official
Kristin	Munsch	kmunsch@citizensutilityboard.org	Citizens Utility Board of Minnesota	309 W. Washington St. Ste. 800 Chicago, IL 60606	Electronic Service	No	OFF_SL_17-401_Official
Rolf	Nordstrom	rnordstrom@gpisd.net	Great Plains Institute	2801 21ST AVE S STE 220 Minneapolis, MN 55407-1229	Electronic Service	No	OFF_SL_17-401_Official

First Name	Last Name	Email	Company Name	Address	Delivery Method	View Trade Secret	Service List Name
Regulatory	OTP	OTPRegulatory@otpco.com	Otter Tail Power Company	PO Box 496 215 S Cascade St Fergus Falls, MN 56538	Electronic Service	No	OFF_SL_17-401_Official
Audrey	Partridge	apartridge@mncee.org	Center for Energy and Environment	212 3rd Ave. N. Suite 560 Minneapolis, Minnesota 55401	Electronic Service	No	OFF_SL_17-401_Official
Generic Notice	Residential Utilities Division	residential.utilities@ag.state.mn.us	Office of the Attorney General-RUD	1400 BRM Tower 445 Minnesota St St. Paul, MN 551012131	Electronic Service	Yes	OFF_SL_17-401_Official
Joseph L	Sathe	jsathe@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-401_Official
Doug	Scott	dscott@gpisd.net	Great Plains Institute	2801 21st Ave Ste 220 Minneapolis, MN 55407	Electronic Service	No	OFF_SL_17-401_Official
Will	Seuffert	Will.Seuffert@state.mn.us	Public Utilities Commission	121 7th Pl E Ste 350 Saint Paul, MN 55101	Electronic Service	Yes	OFF_SL_17-401_Official
Patricia F	Sharkey	psharkey@environmentallawcounsel.com	Midwest Cogeneration Association.	180 N LaSalle St Ste 3700 Chicago, IL 60601	Electronic Service	No	OFF_SL_17-401_Official
James M	Strommen	jstrommen@kennedy-graven.com	Kennedy & Graven, Chartered	150 S 5th St Ste 700 Minneapolis, MN 55402	Electronic Service	No	OFF_SL_17-401_Official
Lynnette	Sweet	Regulatory.records@xcelenergy.com	Xcel Energy	414 Nicollet Mall FL 7 Minneapolis, MN 554011993	Electronic Service	No	OFF_SL_17-401_Official
Jeff	Zethmayr	jzethmayr@citizensutilityboard.org	Citizens Utility Board	309 W. Washington, Ste 800 Chicago, IL 60606	Electronic Service	No	OFF_SL_17-401_Official