minnesota power
AN ALLETE COMPANY

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February 20, 2019

VIA ELECTRONIC FILING

Daniel P. Wolf
Executive Secretary
Minnesota Public Utilities Commission
121 7th Place East, Suite 350
St. Paul, MN 55101-2147

Re: In the Matter of Minnesota Power's May 1, 2018 Compliance Filing for its Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project
Docket No. E015/M-12-233

Dear Mr. Wolf:

Minnesota Power submitted its 6-month compliance filing in the docket on November 1, 2017. Along with reporting all required information, the Company also requested an extension of its 12 month compliance date.

In its February 13, 2018 Order in the docket, the Commission accepted Minnesota Power's 6-month compliance report as complete. In response to the Company's request for an extension on the 12-month compliance date, the Commission bifurcated the original compliance deadlines. The Commission ultimately required Minnesota Power to file a 12-month compliance report on May 1, 2018, but divided the contents of the original 12-month compliance report into two reports, one due on May 1, 2018, and another September 1, 2018. Order Points 2 and 3 from the February 2018 Order in the docket read as follows:

- By May 1, 2018, Minnesota Power shall file a 12-month compliance report that discusses feedback from customers and lessons learned from the TOD Rate Pilot.
- By September 1, 2018, Minnesota Power shall file a compliance report that presents alternative rate designs and TOD periods for its TOD rate.

In its August 20, 2018 Order in the docket, the Commission accepted Minnesota Power's May 1, 2018 compliance report as complete and took no action on the Company's proposed options for altering the TOD Rate. The Commission also ordered the discontinuation of formal evaluation of the current TOD Rate and its participants, and beginning one year from the date of the

Commission's Order, and for a period of two years, required Minnesota Power to submit annual informational filings providing a summary of the TOD Pilot Program, including participation rates, an update on meter communications infrastructure, and plans to offer a system-wide rollout of residential TOD rates. The Order also extended the deadline for Minnesota Power to file its 12-month compliance report on alternative rate designs from September 1, 2018, to February 1, 2019. The Order also requires the Company to provide the following information in this compliance report:

- system information about its peak demand, its peak demand consistent with Midcontinent Independent System Operator ("MISO"), and the hourly cost of meeting its peak demand;
- more information about Minnesota Power's Meter Data Management request for proposals; and
- a discussion of what goals Minnesota Power believes should be addressed by the TOD rate.

This compliance filing satisfies the Company's 12-month compliance reporting requirement, outlines the Company's stakeholder engagement efforts and outcomes, and provides the Commission with an outlook of how a system-wide Time-of-Day rate could be implemented in Minnesota Power's service territory. The Company looks forward to the opportunity to work with the Commission to review the information and recommendations contained in its Time-of-Day Rate February 20, 2019 Compliance filing.

Please contact me at the number or email above with any questions related to this Compliance filing.

Respectfully,

Jenna Warmuth

JW:sr
Attach.

MINNESOTA POWER'S TIME-OF-DAY RATE COMPLIANCE

In the Matter of Minnesota Power's Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project

DOCKET NO. E015/M-12-233

February 20, 2019

Jenna Warmuth (MP)

Executive Summary

Minnesota Power outlines through this compliance filing the Company's stakeholder engagement efforts and outcomes, meter data management considerations, alternative rate design analysis, customer bill impacts and rate implementation considerations, and provides the Commission with an outlook of how a system-wide Time-of-Day rate could be implemented in Minnesota Power's service territory.

Purpose of a Time-of-Day Rate

Time-of-Day rates are an evolution in rate design aimed at creating customer behavior changes in energy use. A Time-of-Day rate structure uses price signals to encourage reduction of energy demand when system costs are high, and subsequent shifting of energy demand to times when system costs are low. By facilitating customer behavior change in energy usage, a Time-of-Day rate structure could be seen as a precursor to flexible energy use rates in the future that support continued integration of variable renewable energy supply into the system and overall decarburization of energy usage.

Stakeholder Process

The Company completed a robust and informative stakeholder process enhanced by the facilitation skills of the Great Plains Institute and Center for Energy and the Environment. The Stakeholder process included a series of four stakeholder meetings. This process established two objectives and six "must have" principles as a baseline for the alternative rate design analysis, along with other considerations imperative to be considered in development of innovative rate offerings. The Company also facilitated two in-person customer meetings in its service territory along with an online customer survey.

MDM and Metering Considerations

The Company is currently deploying innovative rate and program enabling advanced metering infrastructure ("AMI") across its service territory. Over 50 percent of Minnesota Power's meters in the field are AMI, with current deployment at roughly 6-8% per year. Along with AMI deployment, Minnesota Power has previously addressed the need for a meter data management ("MDM") solution in relation to a system-wide rollout of a TOD rate. As communicated in this filing, Minnesota Power's planned MDM implementation and integration is a strategic investment for the Company beyond enabling TOD rates. In relation to TOD rates, the presence of a MDM will create a more user-friendly experience for customers and also has the potential to drastically reduce manual billing and programming issues currently experienced with customized rates and programs.

Alternative Rate Design Analysis

The Company retained the expertise of Lon Huber of Navigant Consulting to augment its rate design and analysis. In this compliance filing Minnesota Power addresses, among other things, Minnesota Power and MISO's peak demand, the hourly cost of serving peak demand, and three options for alternative rate designs and peak periods.

Preferred TOD Rate Design Options - Average Prices (c/kWh):

	Option 1	Option 2	Option 3
Peak	16.8	13.8	14.9
Off-peak	9.2	9.2	9.2
Super off-peak	6.7	6.7	6.7

Final Rate Design Options – Time Periods:

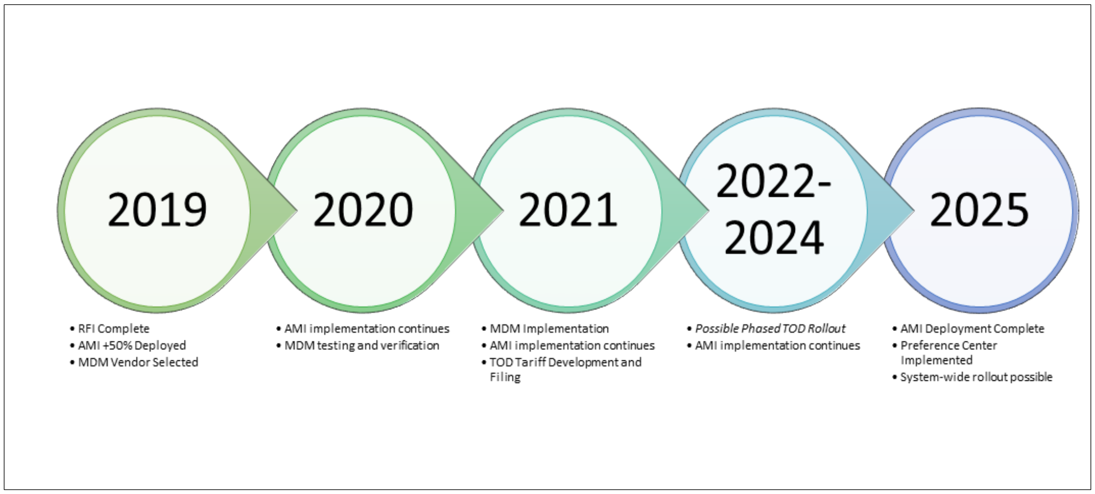
	Option 1	Option 2	Option 3
Peak:	3:00 PM – 8:00 PM weekdays in Dec – Feb and Jun – Sep	3:00 PM – 8:00 PM weekdays	5:00 PM – 9:00 PM weekdays in Nov – Apr 2:00 PM – 6:00 PM weekdays in May – Oct
Off-peak	All other times	All other times	All other times
Super off-peak	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM

Customer Bill Impacts

Stakeholders communicated clearly that bill impacts are a serious concern for some customer classes when considering implementation of a TOD rate. In this filing the Company has provided preliminary bill impact assessments and examples to give stakeholders and the Commission a cursory representation of how these preferred rate options would affect customers' bills. In general, the Company's initial analysis of the preliminary rate options does not demonstrate disparity of billing impacts between low income and standard residential customers.

Rate Implementation

With the complete deployment of AMI, Minnesota Power's AMI system will be technically capable of supporting a system-wide time varying rate offering. However, in all practicality, an MDM solution needs to be in place systemically before a system-wide rollout of this type of rate/program. Though there was not general consensus on a specific deployment plan, the stakeholder workgroup discussed the possibility of a phased deployment and produced a preliminary timeline for consideration as depicted below.



The Company also discusses key components of customer education, costs of full-scale implementation and future tracking, reporting, and measuring considerations required for a largescale TOD rate rollout.

Conclusion

The Company is pleased to share its findings from its important and informative TOD stakeholder process. Looking towards the future and examining innovative rate offerings ensures that the Company continues to meet its customer's and stakeholder's needs while also potentially providing benefits to the electric system.

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STATE OF MINNESOTA
BEFORE THE
MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of Minnesota Power's Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project	Docket No. E015/M-12-233 **February 2019 Compliance Filing**

I. Introduction

Minnesota Power (or, "the Company") submitted its Petition for Approval of a Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project ("Petition") to the Minnesota Public Utilities Commission ("Commission") on March 20, 2012. This Petition sought Commission approval of its proposed rider for a residential Time-of-Day Rate ("TOD Rate" or "Rate") with Critical Peak Pricing ("CPP") for participants in Minnesota Power's Smart Grid Advanced Metering Infrastructure Pilot Project ("Pilot Project"). The Petition was approved on November 30, 2012 and the final rate was made available for customer adoption in October of 2014.

Minnesota Power submitted its first annual Compliance Filing ("Compliance Filing") for its Temporary Rider for Residential Time-of-Day Rate for Participants of the Smart Grid Advanced Metering Infrastructure Pilot Project to the Commission on March 25, 2016. The Commission approved Minnesota Power's petition to continue the Time-of-Day Rate for existing participants in its February 15, 2017 Order in the docket. In this Order the Commission approved modifications to Minnesota Power's Pilot Rider for Residential Time-of-Day Service as outlined below:

- Adjust rate design to assume 25 hours of CPP (instead of 100); and
- Adjust the on-peak adder to $0.04870/kWh (instead of $0.01415/kWh).

These modifications were effective May 1, 2017. In addition, the Commission required Minnesota Power to file compliance reports 6 and 12 months from the date the new rate became effective. Minnesota Power submitted its 6-month compliance filing on November, 1, 2017. Along with reporting all required information outlined in the Notice, the Company also requested an extension of the 12 month compliance date.

In its February 13, 2018 Order, the Commission accepted Minnesota Power's 6-month compliance report as complete. In response to the Company's request for an extension on the 12-month compliance date, the Commission bifurcated the original compliance deadlines. The

Commission ultimately required Minnesota Power to file a 12-month compliance report on May 1, 2018, but divided the contents of the original 12-month compliance report into two reports, one due on May 1, 2018, and another September 1, 2018.

Minnesota Power filed its 12-month compliance report on May 1, 2018. The May 1 Report outlined experiences and lessons learned from the prior 12 months of the Time-of-Day Rate Pilot. In the Report, the Company proposed three options for current participants of the Time-of-Day Rate for the Commission's consideration.

- Option A - Discontinue the TOD Rate Pilot.
- Option B - Remove the CPP component and assume those hours as on-peak, adjusting the on-peak adder from \$0.04870/kWh to \$0.05875/kWh (approximately 1 cent per kWh) while retaining the off-peak discount at \$-0.02990.
- Option C - Remove the CPP component. Retain the on-peak adder at \$0.04870/kWh. Adjust the off-peak discount from -\$0.02990/kWh to -\$0. 02480/kWh.

In its August 20, 2018 Order in the docket, the Commission accepted Minnesota Power's May 1, 2018 compliance report as complete and took no action on the Company's proposed options for altering the TOD Rate. The Commission also ordered the discontinuation of formal evaluation of the current TOD Rate and its participants, and beginning one year from the date of the Commission's Order, and for a period of two years, required Minnesota Power to submit annual informational filings providing a summary of the TOD Pilot Program, including participation rates, an update on meter communications infrastructure, and plans to offer a system-wide rollout of residential TOD rates. The Order also extended the deadline for Minnesota Power to file its 12-month compliance report on alternative rate designs from September 1, 2018, to February 1, 2019. The Order also requires the Company to provide the following information in this compliance report:

- system information about its peak demand, its peak demand consistent with Midcontinent Independent System Operator ("MISO"), and the hourly cost of meeting its peak demand;
- more information about Minnesota Power's Meter Data Management request for proposals; and
- a discussion of what goals Minnesota Power believes should be addressed by the TOD rate.

This compliance filing satisfies the Company's 12-month compliance reporting requirement, outlines the Company's stakeholder engagement efforts and outcomes, and provides the Commission with an outlook of how a system-wide Time-of-Day rate could be implemented in Minnesota Power's service territory. It is important to note that no conclusive stakeholder consensus was reached in terms of a preferred rate design. As communicated through this filing, the stakeholder workgroup reviewed multiple versions of differing rate designs and ultimately did not reach consensus regarding which rate was most reasonable, or if a time varying rate ultimately makes sense for Minnesota Power's system considerations. This filing outlines the progress made thus far via the stakeholder workgroup. There are certain components of the alternative designs (i.e., customer exclusions, and programming costs) that would need to be clarified further in a future program and tariff filing. These design components will require additional thoughtful and proactive stakeholder input prior to a program filing and are discussed in the appropriate sections within this filing.

Minnesota Power does not view the rate alternatives presented in this filing as final, and asserts that the Company should not implement a full scale Time-of-Day offering until a Meter Data Management ("MDM") solution is fully implemented and functional for its service territory. This filing is intended to represent a step forward in developing appropriate time varying rates that are built from stakeholder input, Minnesota Power's specific system considerations, and customer preferences.

II. Stakeholder Process

In its February 2018 Order in the docket, the Minnesota Public Utilities Commission ordered Minnesota Power to engage stakeholders in evaluating alternative rate designs and TOD periods for a system-wide TOD rate. In response to the Commission's Order, Minnesota Power held a series of four meetings with stakeholders, and two in-person customer meetings in order to gain stakeholder input into the Company's prospective TOD Rate designs. These meetings have proven to be a thoughtful and constructive exercise for both the Company and its stakeholders, as the meetings highlighted the unique aspects of Minnesota Power's system considerations for stakeholders and facilitated a positive dialogue and shared learning between participants.

Minnesota Power retained the expertise of Lon Huber (Navigant Consulting) to augment the Company's research and analysis during this stakeholder process. Mr. Huber and his team were instrumental in using their professional expertise to incorporate stakeholder input on the complex and provocative topics inherent in TOD rate design. Mr. Huber is a nationally recognized expert on time varying rate design and is well known to, and respected by, the Commission and Minnesota Power's stakeholders.

Minnesota Power also procured external facilitation resources by partnering with the Great Plains Institute and the Center for Energy and the Environment. Minnesota Power kicked off its stakeholder process to evaluate alternative rate designs in September of 2018. A full summary of the meetings and stakeholders perspectives is provided as Attachment A to this filing.

1. MEETING SUMMARIES

Minnesota Power held its first stakeholder meeting at the Great Lakes Aquarium in Duluth, MN on Tuesday, September 11, 2018. This meeting focused on current metering and communications infrastructure and shared objectives and design principles. The second meeting took place at the Mill City Museum in Minneapolis on Friday, September 28, 2018. This meeting focused on Minnesota Power's system load characteristics and findings from its Smart Grid Pilot. The third meeting was once again held at the Mill City Museum on December 10, 2018. The meeting focused on feedback from Minnesota Power's customer survey and workshops and Minnesota Power's draft TOD rate recommendations, alternative rate options, and analysis. The fourth and final meeting was held via webinar on January 11, 2019 and focused on further refined TOD rate design options.

Representatives from Citizens Utility Board, Fresh Energy, Department of Commerce, and the Office of the Attorney General were able to attend all or most meetings either in person or via phone or webinar. The City of Duluth and Ecolibrium 3 were able to attend some meetings. Energy CENTS Coalition and the Citizens Federation were not able to attend any meetings. All participants received communications and updates prior to and post meetings.

The past TOD Pilot Program learnings and current stakeholder processes are important components of modernizing the customer experience and positioning the Company for business model evolution. The process has provided insight into the desires and needs of Minnesota Power's stakeholders and residential customers, and is a step towards identifying innovative programming that has the potential to optimize system benefits and reduce costs for all customers.

2. OBJECTIVES AND PRINCIPLES

The stakeholders participating in this TOD process spent a substantial amount of time delving into the appropriate principles and objectives under which to develop Minnesota Power's alternative TOD rate designs. The group established two agreed-upon objectives and six "must have" principles as a baseline for the alternative rate design analysis.

Objectives:

1) Reduce system costs, including consideration of peak demand, the need for future investments in the system, and other costs (e.g. market costs).
2) Increase customer participation and satisfaction, with participation loosely defined as the number of customers actively reducing their on-peak load, and satisfaction based partly on the opportunity to reduce costs.

"Must Have" Design Principles:

1) Provide an evaluation of the costs and the benefits of the TOD program.
2) Include considerations for indemnifying low-income customers.
3) Enable energy conservation, cost-effective integration of additional renewables, and reduction of greenhouse gas emissions.
4) Provide rates that accurately reflect the costs of energy cost to serve, both now and looking forward.
5) Consider using an opt-out approach for the base TOD rate.
6) Give customers adequate tools to access and understand their usage data.
7)

The full set of design principles, along with further information regarding participant feedback, is outlined in Attachment A of this report.

3. CUSTOMER SURVEYS & ENGAGEMENT

In October of 2018 an online survey from Minnesota Power was promoted to customers through various digital channels, including social media, TOD Pilot Program past and present participants and known electric vehicle owners. The survey was released on October 17, 2018 and closed on November 15, 2018. The Company received 229 (1 Partial) responses[1] to the survey, 111 of which had a past or present connection to the TOD Pilot Program. The responses to the survey are an indication of the preferences and viewpoints of the Company's highly-engaged customers and may not represent the opinions of the entire customer base. Some high-level observations from the survey include (complete results included in Pages 73-90 of Attachment A):

- Saving money would be the #1 driver for interest in a TOD rate
- 47 percent of customers surveyed are interested in purchasing or currently own an electric vehicle ("EV")
- 80 percent of customers that responded to the survey are interested in TOD
- Over 90 percent are home owners (vs. renters – not representative of Minnesota Power's overall customer base)

Minnesota Power also held two in-person customer meetings in its service territory in October; one in Duluth, MN and one in Little Falls, MN. Minnesota Power staff presented information on the Company's system considerations, resource mix, current residential programs, and general information on demand response programs and Time of Day rates. The meetings drew a small number of customers, however, the customers that did attend were generally engaged and knowledgeable about their energy usage. Key takeaways from the customer meetings included (full summary and presentation included as Attachment B):

[1] Limitations: online only, potentially biased based of how it was conducted and limited ability to "direct market

- Customers seemed to have an understanding of actions they can take to shift usage
- Clear communication and opportunity for savings are key – complex vs. simple rate design wasn't top of mind
- Generally, the customers felt that the CPP events erased opportunity for savings, but were an important tool to incent behavior change
- Savings is a major motivator – with any new rate they would like to see a comparison to current rates

While limitations exist on the information gleaned from this customer feedback experience, the Company believes it was a vital and worthwhile effort. Minnesota Power will perform further customer engagement prior to any future program offering.

III. Meter Data Management and Metering Considerations

Currently, over 50 percent of Minnesota Power's meters in the field are advanced metering infrastructure ("AMI"). Minnesota Power is actively deploying AMI throughout its service territory, largely through meter attrition, at a rate of approximately 6-8 percent (roughly 10,000 meters) annually, continuing over the next several years. Minnesota Power estimates full deployment of all AMI meters by the end of 2025. This schedule could be accelerated if availability of resources (both workforce and funding) are increased. Along with the AMI meter deployment, Minnesota Power completed implementation of its Radio Frequency AMI network communications infrastructure in 2018.

In its May 1, 2018 compliance filing in the docket, Minnesota Power addressed the need for a meter data management ("MDM") solution in relation to a system-wide rollout of a TOD rate. It is important to note that Minnesota Power's planned MDM implementation and integration is a strategic investment for the Company and the continued progress of the MDM system integration does not hinge on the approval or disapproval of a current or future TOD rate. Nevertheless, the fact that Minnesota Power's current method of administering its TOD Rate is not efficient or quickly scalable is one of many learning experiences that drove the Company's decision to invest in a MDM solution. Currently, each meter is manually programmed to recognize the appropriate bucketing of usage relative to the TOD Rate, specifically meters are programmed to look for Total, On, Off, and CPP pricing reads. This is a manual and time-consuming way to administer the program, and one that would constrain a wider rollout of the TOD Rate prior to MDM implementation.

Upon implementation of its MDM system, the Company will have the capability to bill customers utilizing hourly data received from the meters. Usage bucketing according to TOD periods will be handled by the MDM, thereby removing the need for manual custom programming of meters. Consequently, scalability and speed to enroll customers in a TOD rate will increase significantly and the associated cost will decrease significantly. With a MDM in place, it is easier for the meters to communicate their hourly usage rather than the current practice of getting them to recognize and accept a command. This will result in fewer billing issues and far less manual billing interventions. In the current context, the meters bucket all usage and communicate a large daily file back to the Company's customer information system ("CIS"). With a full AMI/MDM established, the hourly data will be transmitted several times a day, which typically equals greater success. A MDM will also allow for flexibility to efficiently change the time periods of a TOD rate. Currently, making a change to the on-and-off peak time periods, or adding additional usage buckets, would require procurement and/or reprogramming of new meters and a meter exchange for every customer placed on the TOD Rate.

There are many benefits associated with a MDM system implementation that go beyond the added functionality needed for a TOD rollout. Benefits of a MDM system include but are not limited to:

- Improved ability to investigate meter and service anomalies using events and alarms.
- Improved power quality detection.
- Better visibility of load data from aggregated meters.
- Increased ability to identify and take action on meter failures and theft.
- Increased integration with outage systems to reduce outage durations, increased accuracy of estimated restoration times, and reduced customer calls to verify power status.
- Promote data-driven decision-making.
- Establish and improve analytics.
- Improved validation.

The Company completed a request for proposal ("RFP") process and MDM selection in late 2018. As a result of its robust RFP process, the Company selected the Oracle Customer to Meter Solution ("Oracle C2M") in November of 2018. The next step in the MDM implementation process is to select a System Integrator ("SI") to assist with the design, build, testing, and implementation of the Oracle C2M solution. The Company currently has an RFP process underway and anticipates SI selection in 3rd quarter of 2019. The presence of a MDM will create a more user-friendly experience for customers and also has the potential to drastically reduce manual billing and programming issues currently experienced with customized rates and programs.

IV. Alternative TOD Rate Design Analysis

1. MINNESOTA POWER SYSTEM INFORMATION

In its August 20, 2018, Order Accepting Compliance Report, Postponing Deadline for Next Report, and Requiring Filings, the Commission ordered that Minnesota Power include in this compliance filing, among other things, certain information about its system, including: Minnesota Power's peak demand, Minnesota Power's peak demand consistent with MISO, and the hourly cost of meeting Minnesota Power's peak demand.

For context, the Company's customer mix (measured by sales volumes) differs significantly from that of a typical U.S. electric utility, and even differs from the average customer mix in Minnesota. The U.S. Energy Information Administration ("EIA") reports total electricity sales to ultimate customers in the United States during 2017 were approximately 37 percent residential, 36 percent commercial, and 27 percent industrial. For that same year the EIA reports sales to ultimate consumers in Minnesota as 32 percent residential, 35 percent commercial, and 33 percent industrial.[2] In contrast, the Company's sales volume is almost 75 percent industrial, as shown in Figure 1.

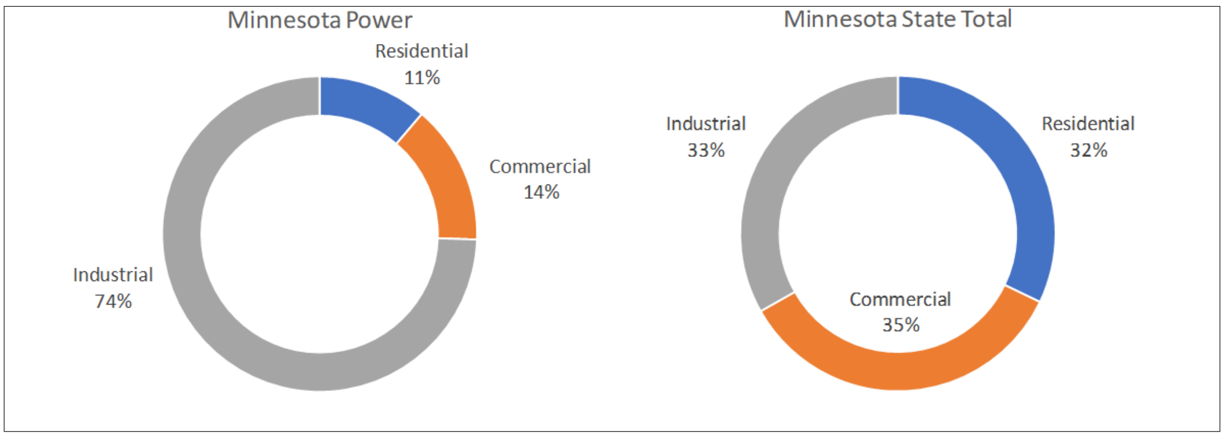

Figure 1: Retail Sales by Customer Class (2017)

a) Minnesota Power Peak Demand

Minnesota Power's system is winter-peaking, with highest demand typically occurring on a winter evening, either in December or in January. Peak demand in 2017 occurred on December 27 at 7:00 PM when system load[3] reached 1,599 MW.

The Company's predominantly industrial sales mix results in a very high load factor with much less daily and monthly variability than a typical utility. Figure 2 below shows the monthly system peak demand projected for the year 2020, reflecting expected peak demand under normal weather conditions. As shown in Figure 2, the Company's peak demand during the summer is forecasted to reach 1,597 MW in July 2020, which is about 1.5 percent lower than the January

[2] https://www.eia.gov/electricity/data/eia861/

[3] Net of customer-owned generation

2020 peak of 1,622 MW. Furthermore, the lowest projected monthly peak in 2020 is 1,455 MW (in May 2020), more than 10 percent lower than the winter peak.

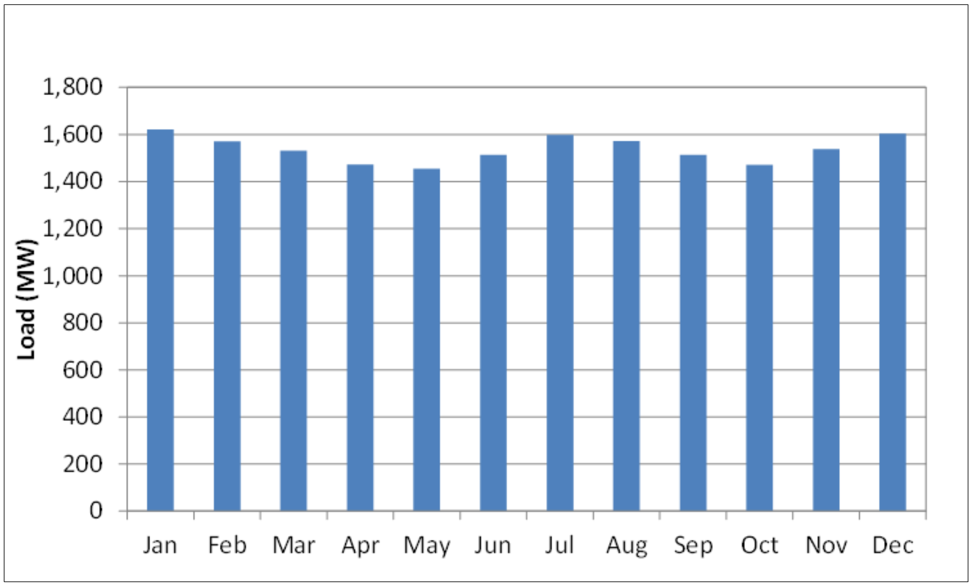

Figure 2: Minnesota Power System Peak Demand by Month 2020 Weather Normalized

It is also notable that the summer system peak typically occurs earlier in the day, in the afternoon, compared to the evening winter peak. Figure 3 below illustrates the daily system load profile for the summer and winter peak days.

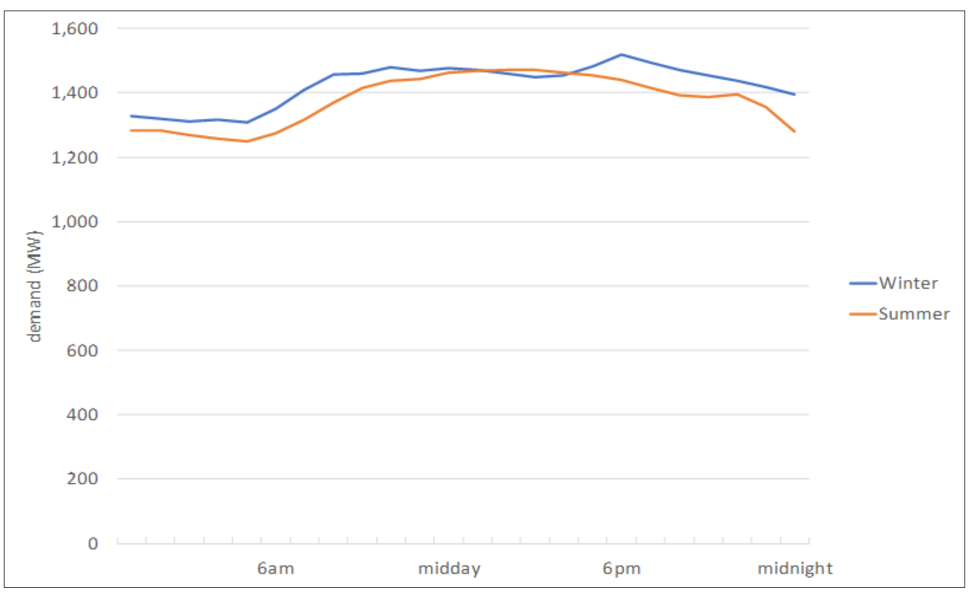

Figure 3: Minnesota Power Daily System Load Profile 2020 Peak Winter and Summer Days

As expected, the Company's residential demand exhibits much more variation than the total system demand profile, both over the course of a year and throughout the day. Similar to the system peak, residential peak demand is highest in the winter.

The daily load profile of the Company's residential customers is similar during the winter and summer seasons, with peak demand occurring in the evening hours. Figure 4 illustrates the daily residential load profile for the summer and winter peak days.

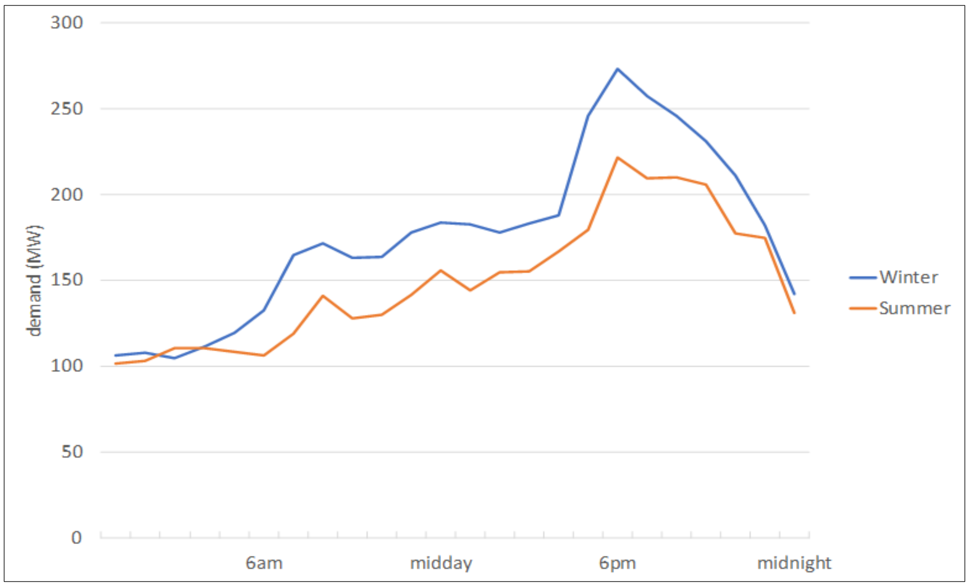

Figure 4: Minnesota Power Daily Residential Load Profile 2020 Peak Winter and Summer Days

b) MISO Peak Demand

Minnesota Power's system sits within MISO Load Resource Zone 1 ("LRZ1") which, in addition to most of the state of Minnesota, encompasses western Wisconsin, north-eastern South Dakota, North Dakota and eastern Montana. Minnesota Power accounts for approximately 10 percent of LRZ1 load.

In contrast to Minnesota Power, MISO LRZ1 is a summer-peaking zone, with the highest demand occurring on a summer day in late afternoon. Across the year LRZ1 load shows more variability than Minnesota Power load, reflecting the more typical load mix (with more residential and commercial load) in LRZ1. Winter peak demand for LRZ1 is approximately 10 percent below summer peak demand.

Figure 5 on Page 11 shows that peak demand in MISO LRZ1 approached 17,000 MW in July 2017.

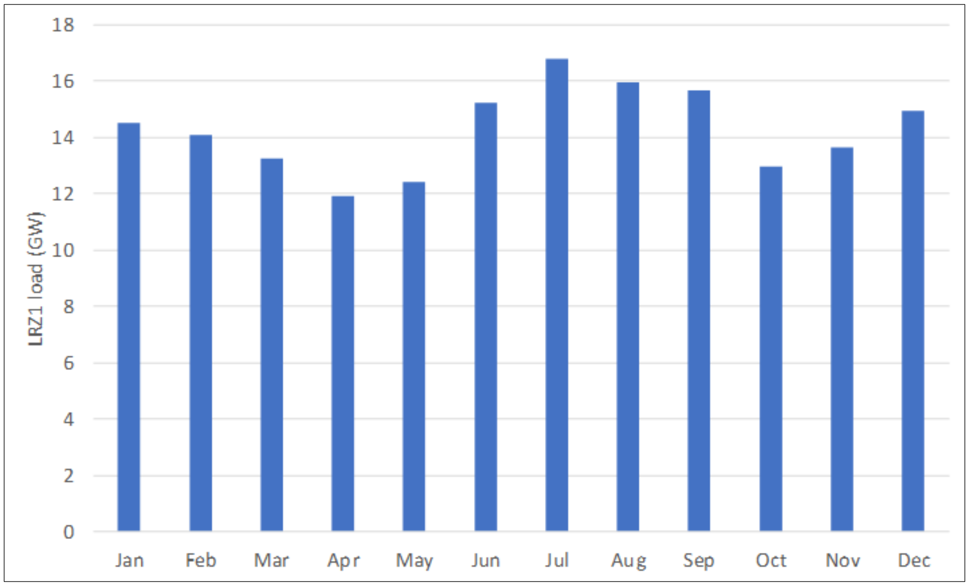

Figure 5: 2017 MISO LRZ1 Peak Demand by Month

Both Minnesota Power's and MISO LRZ1's load profiles differ by season. Figure 6 below illustrates the MSIO LRZ1 daily load profile for the 2017 summer and winter peak days. Summer days exhibited the traditional afternoon ramp into the evening peak hour, while the winter peak day tends to have a dual peak profile, with relatively higher demand in the morning and evening hours.

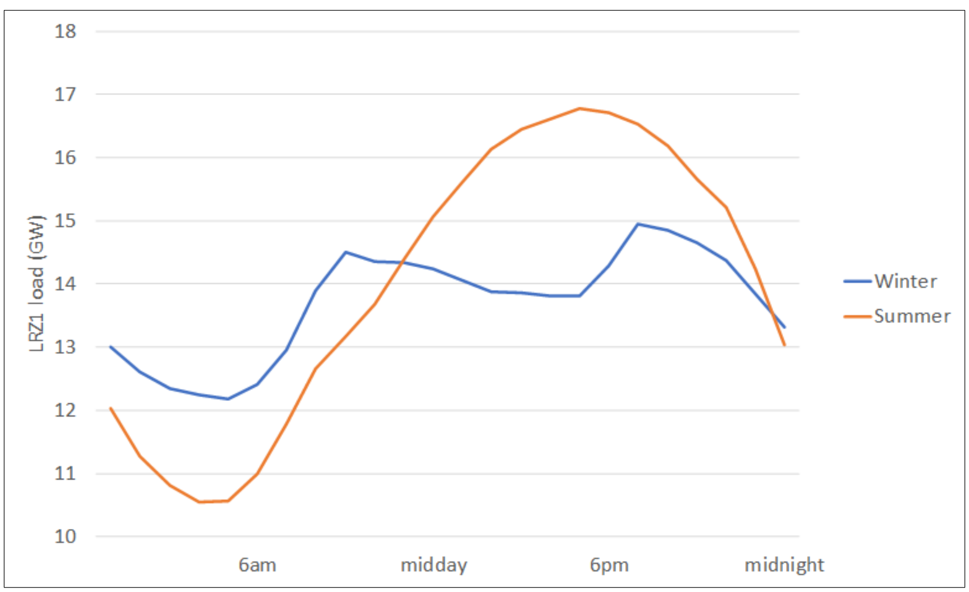

Figure 6: 2017 MISO LRZ1 Profile of Peak Winter and Summer Days

Figure 7 below overlays the Minnesota Power load profile on the MISO LRZ1 profile for July 6, 2017, the peak LRZ1 load day in 2017. MISO LRZ1 load peaked in the hour ending 5:00 PM. On that day Minnesota Power's load peaked at 1,476 MW in the hour ending 4:00 PM (one hour ahead of the LRZ1 peak). Minnesota Power's daily peak of 1,476 MW was 8 percent below its own 2017 system peak of 1,599 MW (which occurred in December). Within the day, the load shapes of LRZ1 and Minnesota Power are broadly aligned; however, the impact of Minnesota Power's concentration of industrial customers creates a flatter load profile.

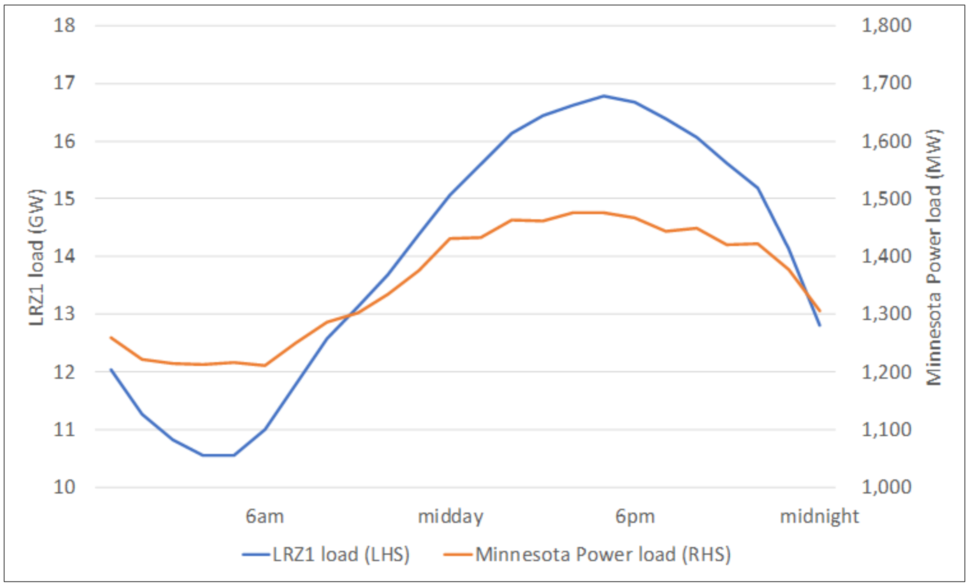

Figure 7: MISO LRZ1 Peak Day Load Profile with Minnesota Power Overlay July 6, 2017

2. HOURLY COST OF SERVING SYSTEM DEMAND

a) Overview of Approach

Many of the costs of serving electric utility customers, for example the fixed infrastructure costs of network and generation assets, are not incurred or observed on an hourly basis. Consequently, to calculate the hourly cost of serving peak demand, Navigant Consulting developed an approach for converting annual costs from the Company's general rate filing into hourly amounts.

The annual costs to serve residential customers were last reviewed in the Company's 2016 general rate case filing and new rates were approved by the Commission on May 29, 2018.[4] In its June 28, 2018 Compliance Filing the Company submitted its electric class cost-of-service study reflecting the Commission's Order; the cost-of-service study classified costs as being either

[4] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR-16-664, May 29, 2018, Order Granting Reconsideration in Part, Revising March 12 2018 Order, and Otherwise Denying Reconsideration Petitions.

capacity-, energy-, or customer-related. The study further allocated the approved test year costs to the Company's various customer classes.

Table 1 shows the Commission-approved annual revenue requirement allocated to the residential customer class, broken down into capacity, energy, and customer classification. Table 1 also identifies the approach used to allocate each cost classification across the hours of a year.

Table 1: Revenue Requirements[5]

Classification	Hourly Cost Allocation	Annual Cost
Capacity	Cost Duration Method	$47m
Energy	Locational Marginal Prices	$31m
Customer	Evenly Allocated	$27m
Total Revenue Requirement		$105m

To convert the annual revenue requirement into an hourly cost to meet demand, the Company allocated annual dollars to each hour during the year using a specific method for each cost classification. For example, capacity costs were determined to be driven by the need to serve the next increment of demand and were allocated to each hour using the Cost Duration Method, discussed in detail in Section 2.b.

Annual energy costs were allocated to each hour based on the hourly locational marginal price ("LMP") at the MISO Minnesota Power ("MP") node. Figures 8 and 9 on Page 14 summarize the MISO MP prices projected for 2020, illustrating the seasonal price fluctuations as well as the daily shape during the winter and summer seasons.

[5] In the Matter of the Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E015/GR-16-664, Compliance Filing dated June 28, 2018, Compliance Schedule 11, page 104 of 104

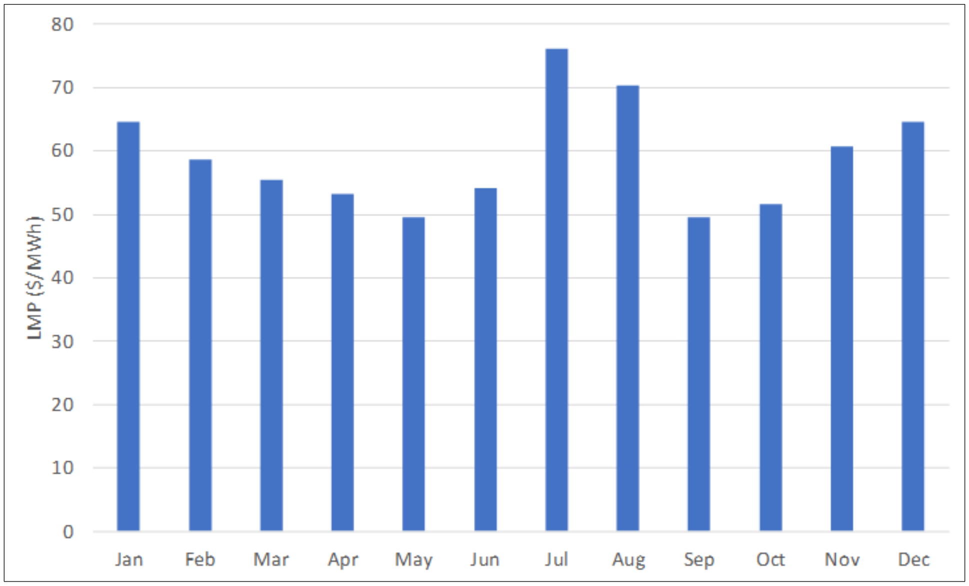

Figure 8: Maximum MISO MP LMP by Month

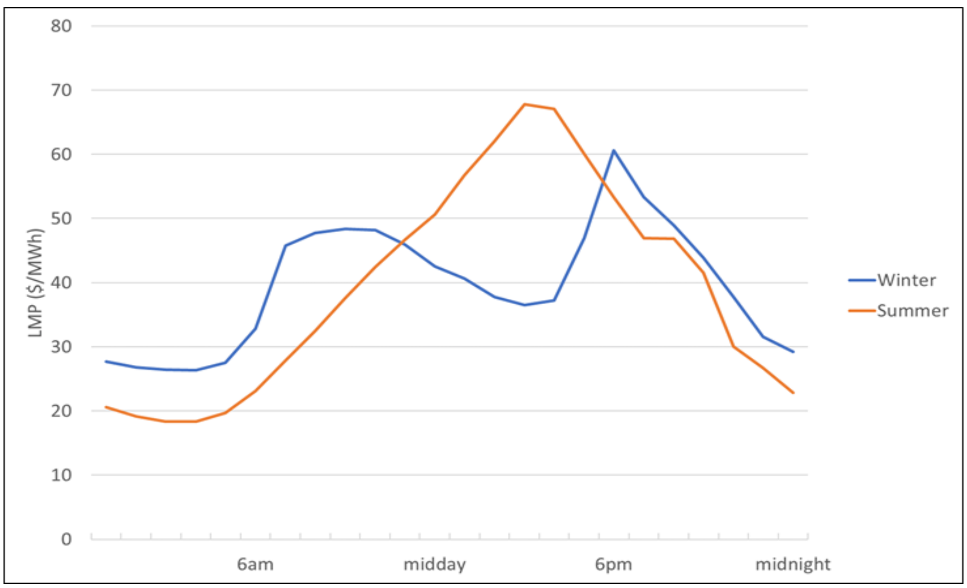

Figure 9: MISO MP Typical Daily LMP Profile by Season

Customer costs (such as metering and administration costs) are fixed costs that are not impacted by level of demand or load on Minnesota Power's system. The Company's residential rates include an $8 per month service charge which covers approximately $11 million of the $16 million annual customer costs. The remaining $5 million of customer costs were allocated evenly across all 8,760 hours of the year.

b) Cost Duration Method

Close examination of a utility's load duration curve (such as Minnesota Power's residential load curve in Figure 10) reveals several features. For example, it's clear some assets are only used to meet demand during a small number of "peak" hours. Thus, it would be appropriate to assign a significant share of costs for these peaking assets to the hours that rank highest on the load duration curve. Similarly, there is a minimum load or "baseload" demand which all hours of the year exceed. Thus, there is some portion of costs which should be assigned equally to all 8,760 hours of the year.

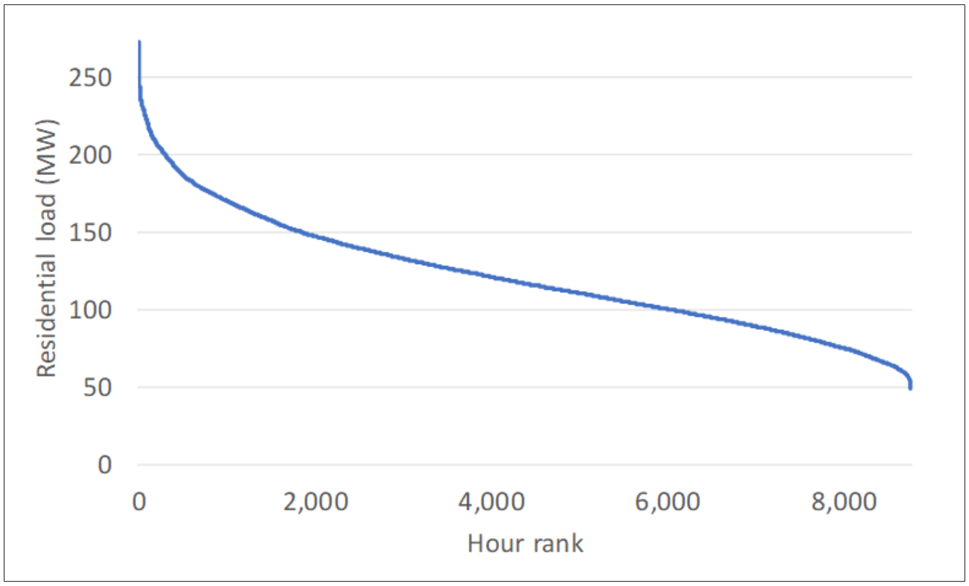

Figure 10: Minnesota Power Residential Load Duration Curve

Navigant Consulting developed a cost duration method designed to capture these features by assigning a share of costs to each hour in a way that reflects the usage as illustrated by the load duration curve. The assignment of costs to specific hours can be further categorized through the steps outlined in the next section.

The Company's capacity costs should be identified at the functional level, i.e. generation, transmission, and distribution because demand for generation, transmission, and distribution capacity is not perfectly coincident. Table 2 on Page 16 breaks down the capacity costs from the Company's electric cost of service study into the respective functions.

Table 2: Minnesota Power Residential Capacity Costs by Function

Function	Annual Cost
Generation	$21m
Transmission	$7m
Distribution	$19m
Total Capacity Cost	**$47m**

For each capacity cost type, specific load duration curves were used to allocate costs across the hours of the year:

- The MISO LRZ1 load duration curve was used to allocate generation capacity costs; the Company's generation capacity requirements (imposed by MISO) are driven by its load during MISO's highest peak demand hours. As described above, peak demand in MISO LRZ1 occurs during different hours than Minnesota Power's native peak demand.
- Minnesota Power's system load duration curve was used to allocate transmission capacity costs; the Company's system load drives the need for new transmission capacity.
- Minnesota Power's residential load duration curve was used to allocate distribution capacity costs; the Company's residential load is the best indicator of distribution capacity requirements in residential areas.

The following steps detail application of the cost duration method to the distribution capacity costs, and the same process was followed with respect to the generation and transmission functions.

Step 1: Calculate the unit cost of capacity

Capacity costs are divided by the peak load of each load duration curve to find a unit cost per MW of capacity.

For example, distribution capacity costs are $19 million and residential peak demand is 273 MW, giving a distribution capacity unit cost of $68,363 per MW.

Step 2: Calculate the incremental load in each hour

The incremental load in each hour is calculated by taking the difference in load between that hour and the hour with the next highest load. For the lowest load hour of the year, the load in that hour is used. Note that the sum of all these incremental load amounts is equal to the peak load.

For example, for distribution capacity the load in the hour with the highest load is 8 MW higher than the second highest hour, which is in turn 6 MW higher the third highest hour, which is in turn 2 MW higher the fourth highest hour, and so on. The lowest load hour has load of 49 MW.

Step 3: Share the incremental load across higher hours

For each hour, the incremental load is shared evenly between the hour in question and all hours of the year that have a higher load than the hour in question. The incremental load at the highest load hour is not shared as there are no higher load hours. The incremental load at the second highest hour is shared evenly between the top two hours, so each gets a one-half share.

For distribution capacity, the 8 MW incremental load in the highest load hour is allocated only to that hour. 3 MW of the 6 MW incremental load in the second highest hour is allocated to that hour and the other 3 MW is allocated to the highest load hour. The 2 MW incremental load in the third highest hour is shared across the top three hours, and so on.

Step 4: Total the load allocated to each hour

The load allocated to each hour is then totaled. The highest load hour has a share of load for all hours of the year, the second highest load hour has a share of load for all hours of the year except the highest hour, and so on.

For distribution capacity, totaling all the load allocated to the highest load hour (8 MW plus 3 MW plus 2/3 MW plus…) gives 14 MW, for the second highest hour (3 MW plus 2/3 MW plus…) gives 7 MW, and so on for each hour.

Step 5: Calculate the total and unit cost of each hour

The load allocated to each hour in Step 4 is multiplied by the unit cost calculated in Step 1 to calculate the total cost of each hour. This can in turn by divided by the billing load in that hour to calculate the unit cost of each hour.

As illustrated in Figure 11 below, the costs are spread to each hour in a manner that closely resembles the load duration curve and therefore reflects system use. This spread of costs to each hour is known as the “Cost Duration Curve.”

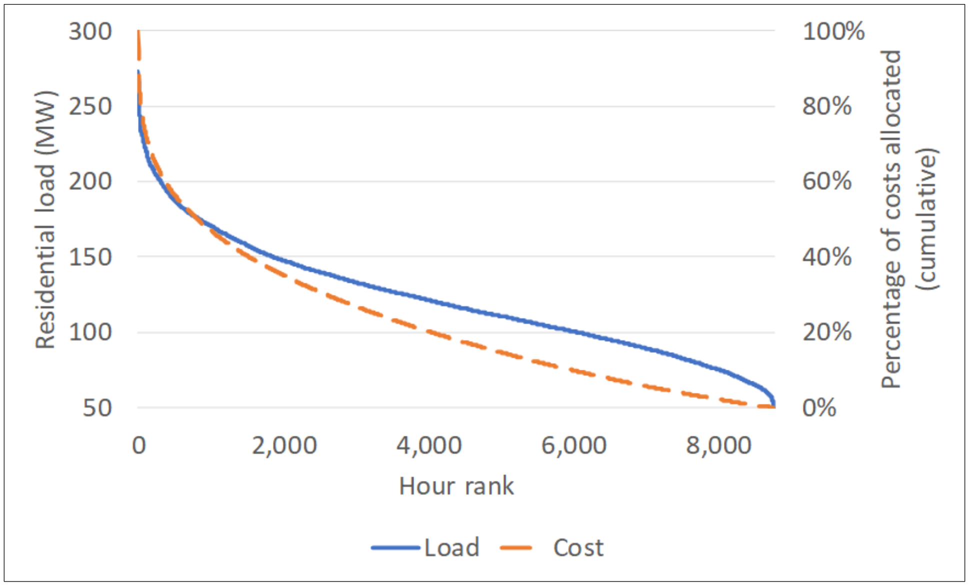

Figure 11: Residential Load and Distribution Capacity Cost Duration Curves

c) Hourly Cost of Serving System Demand

Combining the results of the cost duration method calculations described above for capacity costs with hourly energy costs provides the variable cost of serving residential demand in each hour of the year. Figure 12 shows the hourly costs and illustrates the relative magnitude in each hour.

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	5.6	5.6	5.3	5.1	5.5	5.7	5.2	5.4	5.0	5.3	5.5	5.5
	5.4	5.5	5.2	5.1	5.5	5.8	5.2	5.4	5.0	5.4	5.4	5.4
	5.3	5.4	5.2	5.1	5.5	5.8	5.1	5.4	5.0	5.4	5.4	5.3
	5.2	5.4	5.2	5.1	5.7	5.8	5.2	5.4	5.1	5.5	5.4	5.2
	5.3	5.4	5.4	5.6	5.9	5.9	5.2	5.5	5.4	5.9	5.6	5.3
6am	5.9	6.0	6.2	6.3	6.2	6.2	5.4	5.7	5.7	6.6	6.0	5.7
	7.4	6.9	7.1	6.7	6.5	6.5	5.8	6.1	6.2	6.6	6.5	6.7
	8.2	7.5	7.5	6.8	6.7	6.7	6.3	6.4	6.4	6.8	6.8	7.5
	8.9	7.9	7.6	7.0	6.9	7.1	6.9	6.7	6.7	6.9	7.1	7.9
	8.8	7.8	7.6	6.9	7.0	7.4	7.6	7.0	7.0	7.0	7.1	8.5
	9.3	7.5	7.4	6.7	7.0	7.8	8.6	7.4	7.1	6.9	7.0	8.1
midday	8.5	7.4	7.1	6.5	6.9	8.2	9.9	7.9	7.3	6.8	6.9	8.0
	8.0	7.1	6.8	6.5	6.9	8.7	12.0	8.5	7.6	6.8	6.7	7.9
	7.4	6.8	6.6	6.4	7.0	9.3	15.3	9.4	8.2	6.8	6.6	7.5
	7.1	6.6	6.4	6.3	7.0	9.8	19.0	10.1	8.7	6.8	6.5	7.1
	7.4	6.5	6.4	6.2	6.9	10.2	21.7	10.1	8.8	6.7	6.4	7.4
	9.9	6.9	6.4	5.9	6.6	9.9	25.8	9.5	8.7	6.6	7.5	11.2
6pm	17.3	8.9	7.1	5.8	6.3	9.4	24.7	9.0	8.3	7.4	8.9	33.0
	17.9	9.1	8.1	6.6	6.4	8.7	18.4	8.3	7.9	7.1	8.5	29.9
	15.6	9.0	8.3	6.7	6.6	8.2	14.0	7.9	7.3	6.4	7.8	17.8
	10.5	7.8	7.4	5.9	6.1	7.5	10.3	7.2	6.8	5.9	6.9	12.4
	8.2	6.8	6.4	5.3	5.7	6.7	7.9	6.3	5.9	5.6	6.3	9.4
	6.5	6.2	5.5	5.1	5.5	6.2	6.1	5.7	5.1	5.3	5.9	6.9
midnight	5.9	5.8	5.2	5.0	5.4	5.8	5.4	5.5	4.9	5.3	5.6	5.8

Figure 12: Hourly Variable Cost by Month of Serving Residential Load (c/kWh

Highest cost hours (shaded red) occur in two distinct periods:

- Winter evenings, particularly in December and January, and
- Summer afternoons, particularly in July.

The high-cost winter evening hours reflect the high demand on Minnesota Power's transmission and distribution systems, as well as moderately high LRZ1 system demand and LMPs. The high-cost summer afternoon hours reflect high demand in LRZ1 and high LMPs, as well as moderately high demand on Minnesota Power's transmission and distribution systems.

Lowest cost periods (shaded green) mostly occur overnight and reflect the combination of low demand across LRZ1 and Minnesota Power's systems, and low LMPs.

Costs vary significantly between hours, with the cost to serve load in highest cost hours being up to six times higher than in the lowest cost hours. This variance, while significant, is not at large as other utilities' where times of high system demand and high LMPs are more closely aligned.

3. ALTERNATIVE RATE DESIGNS AND TOD PERIODS

Minnesota Power has offered its current TOD Rate as a pilot program since 2014. This time-of-day rate has been in the form of an adder, or extra charge, on kilowatt–hours (kWh) of energy consumed during "on-peak" hours—defined as 8:00 a.m. to 10:00 p.m. on weekdays, excluding holidays—and a discount on kWh usage during off-peak hours, which are all hours outside of on-peak hours (as depicted in Table 3 below). The rate also includes the option for the Company to declare up to 50 hours per year of Critical Peak Pricing Events during pre-specified time windows, with an adder of 77 cents per kWh applying during these events.

Table 3: Current Rate Structure

Current Rate Structure May 2017 - Present	
On-Peak Hours	08:00 - 22:00 Monday - Friday
Off-Peak Hours	All other hours & designated Holidays
Summer CPP Hours	12:00 - 15:00
Winter CPP Hours	17:00 - 20:00
On-Peak Increase	$0.0487
Off-Peak Discount	-$0.0299
CPP Event Increase	$0.77

a) Approach to designing TOD rates

A core principle of any rate design is to ensure the rates being charged to customers reflect cost causation. When developing a TOD rate, a methodology should be utilized to align prices charged during each TOD period with the costs incurred during the same period. This alignment is intended to accomplish two goals:

1. Ensure rates for each TOD period reflect the cost of meeting demand at those times (i.e. cost causation), and
2. Send a time-differentiated price signal to customers to encourage peak demand reduction.

Constructing TOD rates from hourly costs

TOD rates can be directly derived from the hourly variable costs of serving load shown in Figure 13 on Page 23. Once the TOD time periods have been selected (discussed below), the weighted average of the costs of each hour within each TOD period is calculated. The billing unit (i.e. residential kWh) associated with each hour is used to weight the hourly costs, so higher load hours are weighted more heavily than lower load hours. The remaining portion of customer costs not recovered via the monthly service charge is then added to this weighted average variable cost to calculate the TOD rate.

The TOD rate is initially calculated as a stand-alone rate, but the Company must convert it to the adder/discount structure utilized in the Company's TOD pilot program using the current residential tariff rate as the baseline in order to accommodate the existing inverted block rate ("IBR") structure (more discussion surrounding IBR vs flat rates can be found on Page 26 of this filing).

Preliminary TOD periods

Selecting TOD periods requires balancing a number of different goals such as simplicity for customers (and the utility) and desired size of price differentials between time periods. A peak period narrowly targeted at highest costs hours, such as one that only applies for a small number of (potentially differing) hours during a small number of months, will lead to sharp pricing differentials but may be more challenging for customers and the utility to manage. In contrast, a more broadly targeted peak period, such as one that applies for a larger number of hours year-round, will lead to more muted pricing differentials but may be more appealing to customers.

The Company developed two preliminary TOD period options and associated rates that contrasted in their degrees of targeting and simplicity. The TOD periods were reviewed and refined through the stakeholder process. Through that process the Company developed the set of preferred TOD rate design alternatives that are included in this filing.

Preliminary Option 1 was a targeted peak period option with higher associated peak prices. Peak periods were targeted at hours where the cost to serve was more than 1.3 times the average cost to serve, resulting in peak periods of four hours in length, with the timing of these periods varying between winter (5:00 PM – 9:00 PM) and summer (3:00 PM – 7:00 PM). In the shoulder seasons, spring and fall, there were no peak periods, i.e. off-peak rates applied all day.

Preliminary Option 2 had longer peak periods and relatively lower peak prices. Peak periods applied year-round and were six hours in length so that they covered key high-cost hours in both winter and summer.

For both options the Company employed a three-period structure with peak, off-peak, and super off-peak time periods. Peak periods applied on weekdays only. Super off-peak prices applied overnight throughout the year. The three-period structure allows the Company to target both high-cost and low-cost time periods, which is not possible under a two-period structure that can typically target only one or the other.

b) Stakeholder Feedback on Proposed Rates

Stakeholder feedback on the Company's approach and preliminary options was generally positive. Commenters supported the three-period rate structure and noted that the rates generally seemed well-aligned with underlying costs.

When compared with the Company's existing TOD Rate, stakeholders liked the shorter, more targeted, peak periods which they felt would better enable customer load shifting response. They also felt excluding the Critical Peak Pricing Events made the options simpler, and therefore more favorable, than the current pilot Rate. While the Company agrees the inclusion of a CPP component adds complexity, Minnesota Power would like to note that it also allows for a deeper discount during normal on-peak/off-peak hours by shifting more substantial costs to fewer targeted hours of the year. The trade-off is that customers may be less impacted by day-to-day peak time usage but only realize the benefits of being on a TOD rate if they are able to make substantial changes during CPP event periods. System benefits of the more targeted (but limited) higher cost periods were not evaluated as part of this process so it is not clear how such a structure would impact system efficiencies in comparison to the three-period peak structure explored in this analysis.

Stakeholders provided several suggestions for adjustments to the preliminary options. While they liked the targeted approach of Preliminary Option 1, they felt that having three distinct time periods for summer, winter and shoulder seasons was not customer-friendly and suggested exploring options with only two seasons.

On Preliminary Option 2, commenters felt that the six-hour peak period did not produce rates with sufficient differential between the time periods and suggested reducing the length of peak period to increase the rate differentials. Pages 91-105 of Attachment A to this filing provide examples of rates developed through the stakeholder/analysis process that were ultimately not selected.

Finally, stakeholders suggested looking at ways to reduce the super off-peak price, potentially by shortening the length of the super off-peak time period.

c) Final Preferred Alternatives

Based on this stakeholder feedback, the Company has produced three preferred TOD rate design alternatives.

Table 4: Preferred TOD Rate Design Options - Average Prices (c/kWh)

	Option 1	Option 2	Option 3
Peak	16.8	13.8	14.9
Off-peak	9.2	9.2	9.2
Super off-peak	6.7	6.7	6.7

Table 5: Final Rate Design Options – Time Periods

	Option 1	Option 2	Option 3
Peak	3:00 PM – 8:00 PM weekdays in Dec – Feb and Jun – Sep	3:00 PM – 8:00 PM weekdays	5:00 PM – 9:00 PM weekdays in Nov – Apr 2:00 PM – 6:00 PM weekdays in May – Oct
Off-peak	All other times	All other times	All other times
Super off-peak	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM	11:00 PM – 5:00 AM

Option 1

The rates and time periods for Option 1 are shown in Table 6 and Figure 13 on Page 23.

Table 6: Option 1

	Average Rates (c/kWh)	Adders to Existing Rates (c/kWh)	Time Periods
Peak	16.8	7.2	3:00 PM – 8:00 PM weekdays in Dec – Feb and Jun – Sep
Off-peak	9.2	-0.4	All other times
Super off-peak	6.7	-2.9	11:00 PM – 5:00 AM

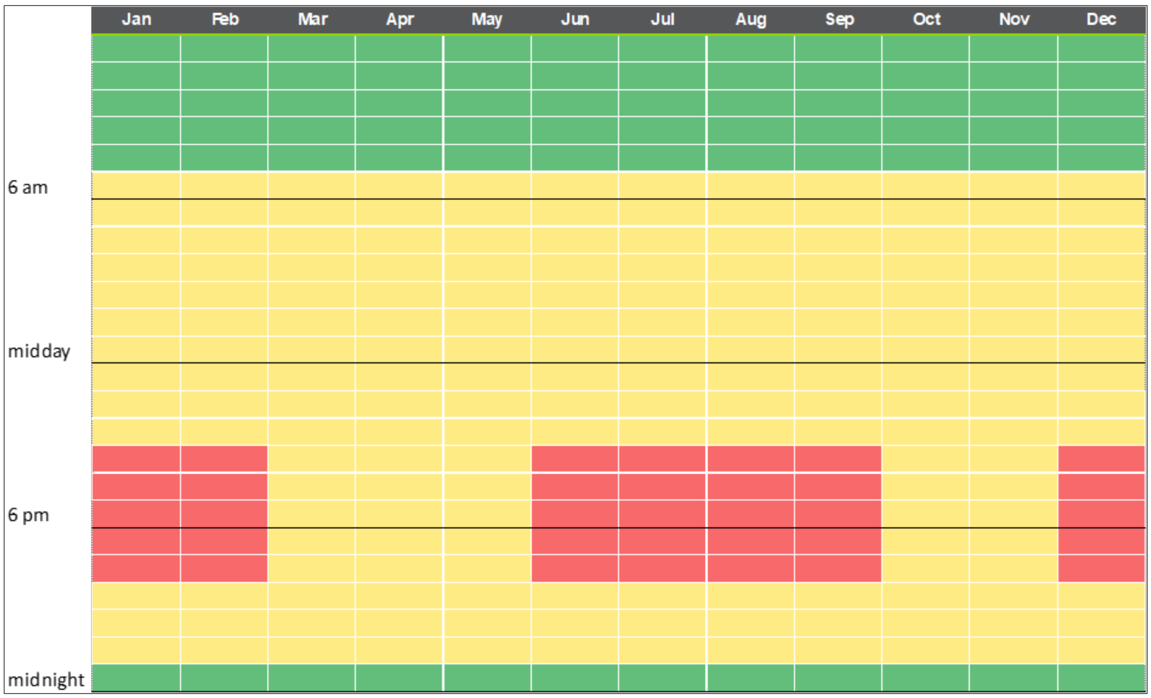

Figure 13: Option 1 Time Periods (red = peak, yellow = off-peak, green = super off-peak)

Option 1 was developed from the Preliminary Option 1 presented to stakeholders. It includes two seasons:

- A 'high' season with a five-hour peak period from 3:00 PM to 8:00 PM, that applies in seven months (December to February and June to September), and
- A 'low' season with no peak periods, that applies in five months (Mar to May and October to November).

The 'low' season with no peak time periods targets the low cost to serve those months of the year. This in turn ensures that peak periods are better targeted towards high cost times and drives a significant price differential between time periods.

Super off-peak prices apply from 11:00 PM to 5:00 AM year-round.

For customers, Option 1 provides the fewest hours with peak prices of the three options and provides the highest potential to save money by shifting load out of peak periods.

Option 2

Table 7: Option 2

	Average Rates (c/kWh)	Adders to Existing Rates (c/kWh)	Time Periods
Peak	13.8	4.3	3:00 PM – 8:00 PM weekdays
Off-peak	9.2	-0.3	All other times
Super off-peak	6.7	-2.9	11:00 PM – 5:00 AM

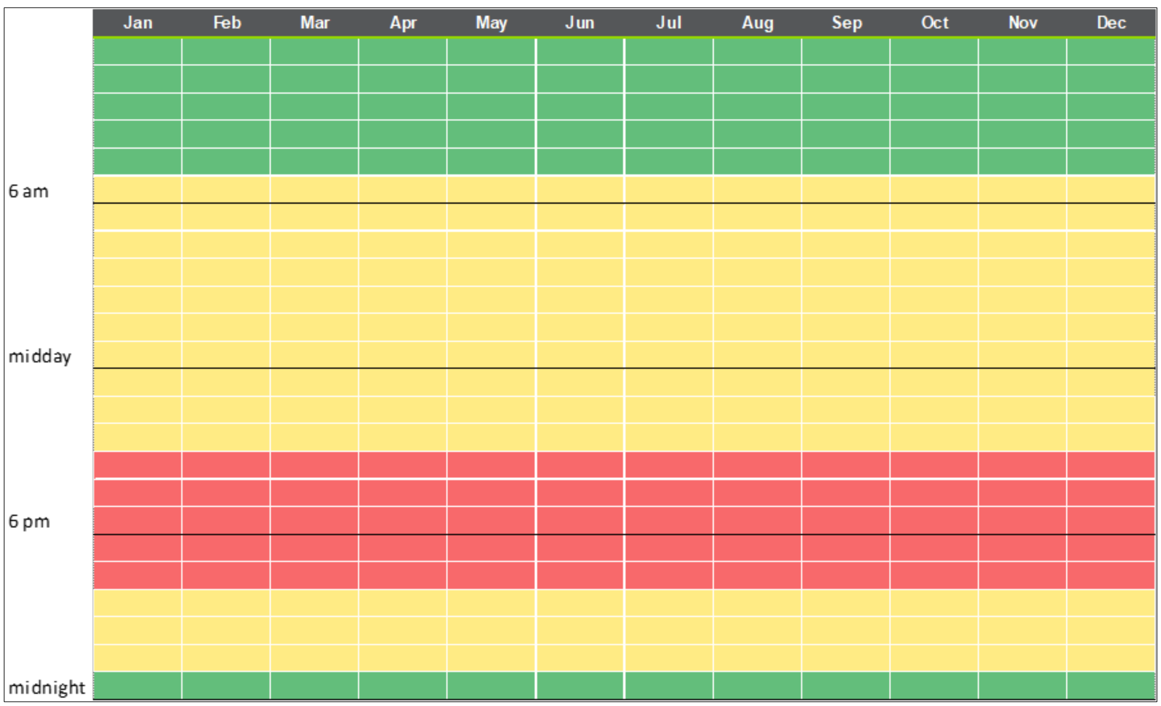

Figure 14: Option 2 Time Periods (red = peak, yellow = off-peak, green = super off-peak)

Option 2 was developed from the Preliminary Option 2 presented to stakeholders. It includes a five-hour peak period year-round from 3:00 PM to 8:00 PM, reduced from six hours under the preliminary option. The five-hour length of the peak period is the shortest possible year-round period that still captures key high-cost hours in both winter and summer.

Super off-peak prices apply from 11:00 PM to 5:00 AM year-round.

Option 2 is the simplest option from a customer perspective. The time periods do not change during the year, enabling customers to adopt a single load shifting approach. The trade-off is that the peak time period is the least targeted of the three options, so the price differential across time periods is muted.

Option 3

The rates and time periods for Option 3 are shown in Table 8 and Figure 15 below.

Table 8: Option 3

	Average Rates (c/kWh)	Adders to Existing Rates (c/kWh)	Time Periods
Peak	14.9	5.3	5:00 PM – 9:00 PM weekdays in Nov – Apr 2:00 PM – 6:00 PM weekdays in May – Oct
Off-peak	9.2	-0.2	All other times
Super off-peak	6.7	-2.9	11:00 PM – 5:00 AM

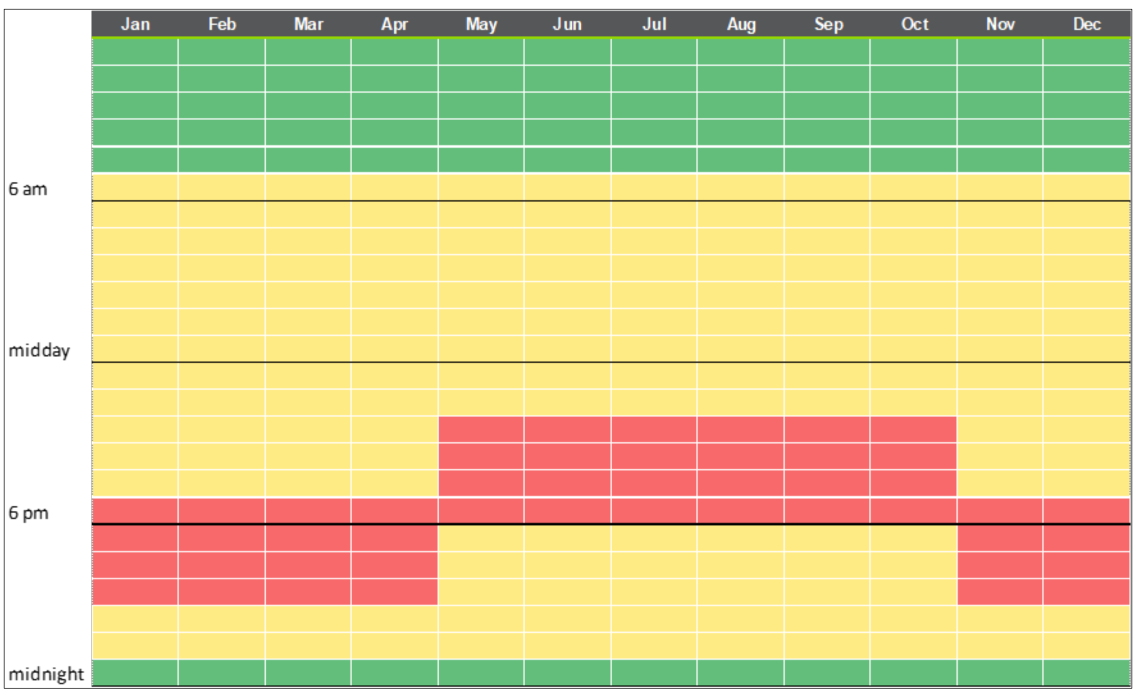

Figure 15: Option 3 Time Periods (red = peak, yellow = off-peak, green = super off-peak)

Option 3 was developed from the Preliminary Option 1 presented to stakeholders. It includes two seasons:

- A ‘winter’ season with a four-hour peak period from 5:00 PM to 9:00 PM for six months, and
- A ‘summer’ season with a four-hour peak period from 2:00 PM to 6:00 PM for six months.

The staggered timing of winter and summer peak periods ensures that high cost hours in the winter evening and late summer afternoons are both covered by peak periods.

Super off-peak prices apply from 11:00 PM to 5:00 AM year-round.

For customers, Option 3 provides an intermediate option between Options 1 and 2: it maintains year-round peak periods but tightens the timing of the peak periods, making them more targeted to high cost hours, increasing the price differentials.

d) Commentary on Price Differentials

The three preferred TOD options do not exhibit as large a price differential between peak and super off-peak prices as seen in TOD rates of many other utilities. There are several contributing reasons for this. First, as outlined in Section IV.1.a, the Company’s system has a very high load factor with little seasonal or hourly load variability. This means that transmission capacity costs are shared relatively evenly over many hours which in turn flattens the rate structure.

Second, as outlined in Section 1.b, the Company’s system is winter-peaking but sits within the summer-peaking MISO LRZ1 zone. The times of highest MISO energy prices and capacity requirements do not coincide with times of highest demand on the Company’s system, leading to a flatter rate structure than if they did coincide.

Finally, as noted in Section 2.a, the Company’s monthly service charge is not sufficient to recover all customer-related costs. Some of these customer-related costs must therefore be recovered through TOD rates, which increases the rates in all periods, thereby reducing the relative differential.

e) Inverted Block Rates and Effect on Dynamic Pricing

Designing TOD rates within Minnesota Power’s current residential rate structure of Inclining Block Rates (IBR) is complex and requires converting the TOD rates from stand-alone rates to adders/discounts as outlined in Section 3.a of this report. Minnesota Power’s standard residential rates currently include four separate blocks, or levels of energy usage, with increasing prices for each successive 400 kWh increase in monthly energy usage. If Minnesota Power were to offer a flat TOD energy rate as an alternative to the standard rate, higher-usage customers who currently pay the highest block rate (14.653¢/kWh for usage above 1,200 kWh per month) would likely benefit from switching to the flat TOD rate. In contrast, lower-usage customers who pay the lowest rate (7.423¢/kWh for usage below 400 kWh per month) would likely pay more on a flat TOD rate, even during off-peak hours.

While IBR are considered by some stakeholders as a method of rate design that can encourage energy conservation and improve affordability for low-usage customers, Minnesota Power in previous annual reports to the Commission on its IBR has been unable to conclude their effectiveness as incentive for energy conservation and as an equitable rate structure for its customers.[6] IBR by definition establishes monthly kWh energy usage levels and applies energy rates that progressively increase with each usage level. The level at which the rate blocks are set can lead to decreases in bills for some customers while significantly increasing others, and are more policy-based than cost-based. Customer affordability may not be materially affected by IBR because total monthly energy use correlates poorly to income and is more affected by other factors such as household size and the energy source used for household appliances. Additionally, in an energy future that would encourage decarbonization through smart integration of renewable energy, IBR serves as a disincentive to customers to select electric fueled home appliances over alternatives. Overall, the issue of using rate design as a conservation incentive requires critical evaluation and analysis of all related factors.

Time-based rate design has an advantage over IBR by more accurately representing time variations in the cost of energy. This will be especially true as the industry begins to face new challenges associated with anticipated changes in resources on the grid. On a TOD rate, customer bills do not change based primarily on the amount of energy used each month, but vary mainly by the time when energy is used. This more closely matches utility energy supply cost variations by season or month of year, day of week, and time of day. IBR, on the other hand, provide a less effective cost signal by recognizing only total monthly energy usage in place of actual cost differences. Building a TOD rate on top of IBR makes the rate design more complex, resulting in price signals and bill impacts that are more difficult to understand, and the effectiveness of the rate design may therefore be diminished. As an example, a customer who purchases an electric vehicle and charges their vehicle solely off-peak is theoretically providing benefits to the system, yet with an IBR, that customer will be penalized because that increased off-peak usage will place the customer in a higher/more expensive IBR tier.

As mentioned in Section I of this report, Minnesota Power does not consider the rate alternatives presented in this filing as final and will continue to evaluate the billing impact of opt-out or system-wide TOD rate offerings built on both its current IBR structure as well as compared to a flat rate or other standard residential rate designs that may be approved by the Commission in the future.

[6] In the Matter of Application of Minnesota Power for Authority to Increase Rates for Electric Service in Minnesota, Docket No. E-015/GR-09-1151, Annual Block Rate Compliance Filings dated January 11, 2013; April 28, 2014; May 5, 2015; July 26-2016, and December 20, 2017.

f) TOD Rates and Customer Generation

Another potential complexity associated with a broader TOD rate offering is how billing on TOD rates would interact with billings and credits for customers with self-generation. The Company is still investigating the metering and billing challenges of implementing TOD rates for a customer with self-generation, such as rooftop solar, which exports energy to Minnesota Power. Initial investigations point to implementation challenges. Minnesota Power's Rider for Parallel Generation has compensation options including the Company's average retail energy rate, simultaneous purchase and sale rate, and time-of-day purchase rate that apply to cogenerators and small power producers rated at 40 kW or less. If technical barriers prove overly arduous, or the costs excessively prohibitive, the Company may consider a single export rate linked to its average retail rate but cannot commit to such a structure absent further investigation. A single export rate arrangement would, however, avoid having to input two or three different prices that change by season and tier. The sheer combination of four standard residential energy rate tiers plus three different daily prices with possible seasonal changes to time periods is not only challenging from a metering and billing perspective but also for customer comprehension and installer economic modeling. The Company will continue to evaluate the programming options available for net metering and other distributed generation customers that may be achievable with the implementation of the MDM.

V. Customer Bill Impacts

Stakeholders communicated very clearly that bill impacts are a serious concern for some customer classes when considering implementation of a TOD rate. The Company has completed preliminary bill impact assessments and examples to give stakeholders and the Commission a cursory representation of how these preferred rate options would affect customers' bills.

A sample of hourly AMI energy use data from Low-Income Home Energy Assistance Program ("LIHEAP") and non-LIHEAP residential customers for a one-year analysis period shows these customers tend to use energy at the same times of the day. The table below shows how similarly LIHEAP and non-LIHEAP customers use energy; under any of the three TOD rate options, the share of energy usage during the on, off, and super-off peak periods are nearly identical. LIHEAP customers do tend to use a greater share of their energy during on-peak periods than non-LIHEAP customers, but they also tend to use more in the super-off peak period.

Table 9: Customer Usage

	Option 1		Option 2		Option 3	
Peak Period	Non-LIHEAP	LIHEAP	Non-LIHEAP	LIHEAP	Non-LIHEAP	LIHEAP
On	13.9%	14.4%	17.3%	17.7%	10.5%	10.7%
Off	66.8%	66.1%	63.4%	62.7%	70.1%	69.8%
Super-Off	19.3%	19.5%	19.3%	19.5%	19.3%	19.5%

Minnesota Power conducted a bill impact analysis (depicted in Figure 16 below) to assess whether or not a TOD rate would negatively affect low-income customers. The customers analyzed fell into four categories: standard residential, electric heating, standard LIHEAP (non-electric-heat), and LIHEAP with electric heat. For rate Option 3, the Company found no evidence that low-income customers differ in their energy usage behavior from non-low-income residential customers, and does not expect low-income customers to be disproportionately affected – positively or negatively – by a TOD rate based on rate Option 3.

The analysis for rate Option 3 showed that a standard (non-electric-heat) LIHEAP customer would have saved between $2.5 and $8 over the period from October 2017 to September 2018, an electric-heat LIHEAP customer would have saved between $16 and $28.5, a standard, non-heating, non-LIHEAP customer would pay between $0.5 and $5 more, and a non-LIHEAP electric-heat customer would save between $29 and $41 per year. When taking into the consideration the peak periods of Option 3, the usage of the LIHEAP customers during the off-peak and super-off-peak periods seems to balance out or negate their on-peak period usage, which meets the objective of the TOD rate design options.

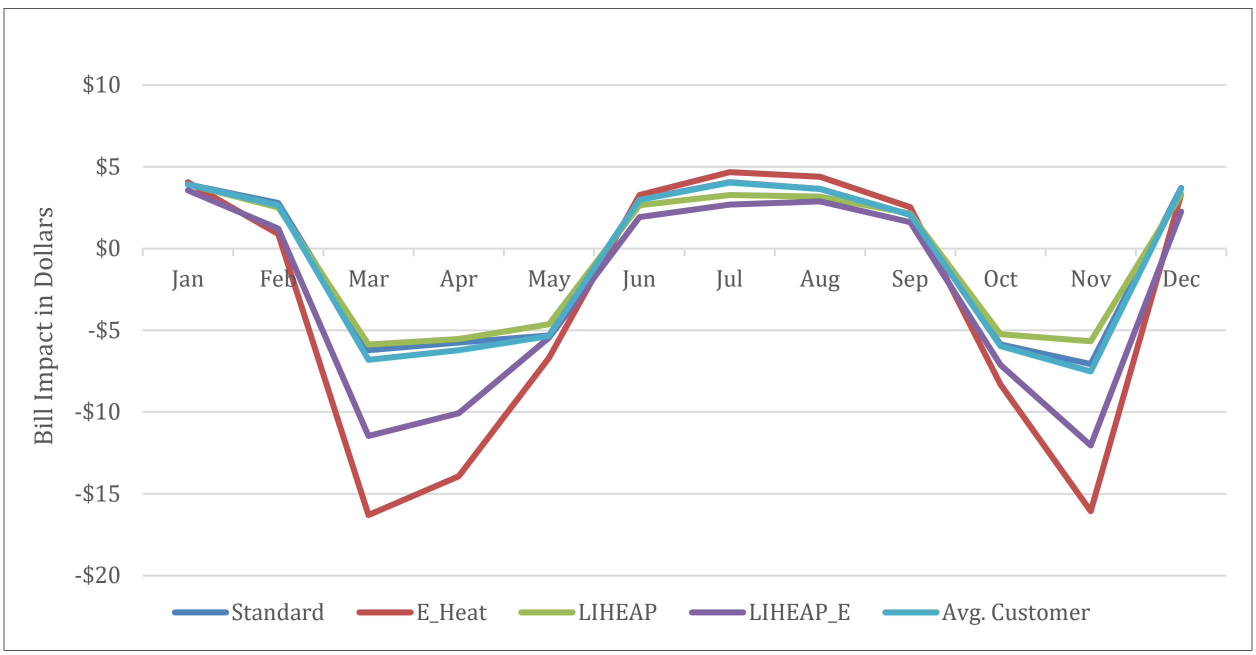

Figure 16: Bill Impacts by Customer

VI. Rate Implementation

1. FUTURE OUTLOOK – IMPLEMENTATION TIMEFRAME

Minnesota Power considers a TOD rate a compelling customer offering in the context of full-scale development. While tangible system benefits may be proven to be relatively minor in the short term, the Company believes that innovative programming such as a TOD rate can play an important role in improving grid efficiency and improve customer satisfaction through providing additional options.

The timeline for a full scale TOD rate rollout is heavily dependent on Minnesota Power's planned MDM implementation and integration (discussed in further detail on Page 6). As communicated in previous filings in the docket, with the complete deployment of AMI, Minnesota Power's AMI system will be technically capable of supporting a system-wide time varying rate offering. However, in all practicality, an MDM solution needs to be in place systemically before a system-wide rollout of this type of rate/program.

Though there was not a general consensus on a specific deployment plan, the stakeholder workgroup discussed the possibility of a phased deployment and produced the preliminary timeline provided below. (Also illustrated in Figure 17 on Page 31).

Phase 1: Before MDM is in place (expected 2019-2020)

This is a planning and preparation period, as benefits likely will not justify the resources needed to manually fix billing errors or costs associated with manually programming each meter with TOD buckets. Specific actions could include:

- Obtain a suitable rate design, then evaluate how to deploy it
- Conduct strategic planning regarding related/ancillary programs to maximize benefit (e.g., energy conservation efforts, electric vehicles, distributed energy resources)

Phase 2: MDM implementation period (expected 2020-2021)

Phase 2 activities could include:

- Pilot the program with some customers (e.g., ~394 current pilot participants and/or EV owners) and conduct shadow billing for all other customers to identify which customers will need the most assistance with such things as managing their usage and understanding their bill. Target programs to help those customers.

Phase 3: Post-MDM implementation, continued AMI deployment (2022-2025)

Potential: phased roll-out of TOD Rate as AMI meters are deployed.

Phase 4: Full AMI deployment with MDM (2025+)

AMI meters and TOD rate are fully deployed to all applicable customers.

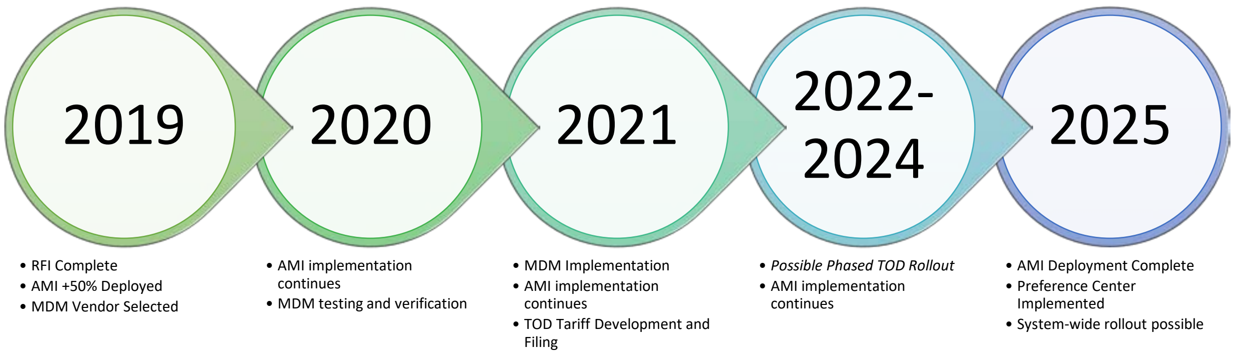

Figure 17: Phased Timeline for TOD Rollout

If the Company were to commit to a phased TOD rate rollout post MDM implementation in 2021 Phase 3), it would require targeted marketing and education outreach efforts, increased administrative resources (to support such activities as shadow billing), and a reconfiguration of the Company's AMI deployment strategy. Along with these considerations would be the uncertainty of enrollment and additional resources needed to match demand. The Company's preference is to have completed both the MDM implementation and AMI deployment prior to a full-scale TOD rate implementation. This would place a full-scale TOD rate offering in the 2024-2025 timeframe.

2. CUSTOMER EDUCATION

Customer communication and education are key components to any innovative utility program, especially when the offering is opt-out or system-wide. As evidenced through its successful implementation of the current TOD Rate Pilot, Minnesota Power is well positioned to provide a smooth and thoughtful transition for its residential customers. Minnesota Power worked closely with Commission Staff during the initial TOD Rate rollout to develop resources, communications, and tools to ensure customer communications were comprehensive and clear. Notably, Minnesota Power earned a first place award under the category of direct mail during the annual Utility Communicators International ("UCI") conference in June 2015 for its Time-of-Day materials. Numerous participant surveys associated with the current TOD rate also indicated a very high level of understanding despite the complexities of the pilot rate design. Minnesota Power intends to capitalize on its learnings from this initial experience while also leveraging the most successful aspects of the program and supplementing with innovative communications tools.

Based on its experience through the TOD Rate pilot, Minnesota Power explored a preference center solution in an effort to realize efficiencies and operational benefits while expanding engagement opportunities with customers. A preference center (aka: subscription centers) is a landing page where you tell a company what kinds of communications you want to receive from them. It's usually linked from the footer of emails—next to the unsubscribe link.[7] A preference center solution would allow customers to choose the preferred frequency and channels (e.g. text message, email, phone call) of their communications coming from Minnesota Power. They could choose which programs they are interested in learning more about and getting updates on. This would provide the utility with a queryable database to utilize in targeting customer communications. Preference solutions are common among many marketing types and customers are beginning to expect this type of communications control from any business with which they interact. Not only will this provide customers with choice, it will also allow the utility to target its programs more effectively and understand its customer needs on a more granular level.

3. COSTS OF FULL-SCALE IMPLEMENTATION

Both Minnesota Power and the Stakeholders who engaged in this process recognize the importance of a strong education and outreach strategy in creating a successful rollout of a full-scale TOD rate. As such, any costs associated with the development and implementation of an education and outreach strategy should be considered as part of the costs to implement the rate. Based on related discussions as part of the stakeholder process and internal expectations and experience, the following items were identified as education and outreach related implementation costs:

Customer Usage and Account Portal: Software enhancements for enabling customers to easily understand their usage in terms of the TOD periods and for development of a bill impact tool designed to aid customers in understanding how the new rate structure will impact their bills and make informed decisions if considering opting out of the program. Based on current vendor pricing and anticipated level of effort, the Company estimates between $50,000 and $100,000 in related implementation costs.

Education and Outreach Communication Plan and Materials: based on current staffing levels, Minnesota Power anticipates an additional resource will be needed to develop, facilitate, and implement a robust communication strategy and the related materials in order to ensure customers are well educated and prepared for implementation of the rate itself.

[7] https://www.leadmd.com/best-practices/blog/whats-a-preference-center-why-you-should-care/

Customer Support: The Company anticipates an additional customer programs and services representative will be necessary for 12 to 18 months surrounding the implementation in order to support the increased call volume and direct customer consultation expected as the rate is deployed. Minnesota Power anticipates an influx of calls related high bill impacts, general inquiries about the rate, requests to understand bill impacts of opting out, etc. Some of these calls could be handled through existing Call Center resources, but many of which would require a more detailed and intensive level of service. Additionally, if the implementation plan requires or includes shadow billing in some form, there would likely be additional implementation and resource costs to consider. The magnitude of these costs would likely depend on the approach employed.

Measurement and Evaluation:

The Company will likely need to invest in the appropriate measurement and evaluation tools and services for tracking progress and effectiveness of a full-scale TOD rate offering. Ensuring that the implemented rates are providing the intended and desired effects will require extensive evaluation and tracking of customer's usage behaviors and effects on the system. The costs related to these activities will depend on the approach employed.

4. TRACKING, REPORTING, AND MEASURING

In its August 18, 2018 Order in the docket, the Commission required Minnesota Power to submit annual informational filings providing a summary of the time-of-day pilot program, including participation rates, an update on Minnesota Power's meter communications infrastructure, and the Company's plans to offer a system-wide rollout of residential time-of-day rates. The Company will continue to report on the pilot as ordered. Additional reporting will be identified as appropriate with the implementation of a new time-of-day tariff. The updated metrics could include such items as estimated peak reduction, participation rates, customer feedback, etc. The Company will continue to share its learnings whether through its current pilot, or a future time-of-day tariff and program.

VII. Conclusion

Minnesota Power gained valuable insight through its TOD stakeholder process. The process has been a positive learning experience supported by industry expertise via Navigant consulting and facilitation by the Great Plains Institute and Center for Energy and the Environment. The lessons learned, and insight gleaned, from the Company's existing TOD Rate were advantageous and key for informing what a full scale TOD Rate may look like on Minnesota Power's system. At the same time, the Company was challenged to contemplate scenarios that may not have been considered viable in the past. The alternative rate designs communicated through this filing are an essential foundation on which the Company can build future rate offerings. Considering the Company's planned MDM implementation timeline, a full-scale TOD Rate is not advisable until the 2024 timeframe (as outlined on Pages 30-31). Keeping this in mind, the Company is motivated to take the lessons learned through its stakeholder process and continue refining the rate design options with further feedback and analysis. The Company looks forward to continuing the dialogue regarding the appropriateness and possible designs of time varying rates for its customers.

Dated: February 20, 2019

Respectfully submitted,

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Minnesota Power
Time of Day Rate Design Recommendations
Summary of Stakeholder Meetings

February 14, 2019

Process facilitated by the Great Plains Institute and Center for Energy and Environment

Questions about this summary should be directed to:

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Table of Contents

I. Introduction

Time-varying rates, in which the price of electricity varies across the time of day and possibly throughout the year, have been adopted by many utilities for decades. Increasingly, these rates are being deployed as one of many strategies to address profound changes affecting the electric system, including advances in technology, an increasing desire for more customer choice, and pressure to reduce carbon emissions.

Time-varying rates touch on all of these changes and can have a number of benefits. New metering and communications technology makes it possible to much more accurately measure how much electricity a customer used during specific times of the day and bill those times at different prices. Customers who can respond to a time-varying rate by shifting some of their electricity usage from a high-cost time of day to a low-cost one can benefit by reducing their electric bills. If many customers respond in this way, a time-varying rate can reduce the need for fossil fuel-powered electricity generation during high-usage times and better utilize renewable electricity such as wind power during low-usage ones. Reducing or shifting peak load in this way can make the entire system more reliable and cost-effective, saving money even for customers who don't participate.

While the concept of a time-varying rate makes sense for many reasons in theory, the details matter. Each electric utility has a different load profile based on its customer base and a different generation mix based on its resources and participation in a regional market. These differences require each rate to be tailored to its unique situation.

This document summarizes the results of a stakeholder engagement process to solicit input on time-varying rate recommendations for Minnesota Power, in compliance with an order from the Minnesota Public Utilities Commission in Docket No. E015/M-12-233 to develop such recommendations following the review of a time-varying rate pilot that concluded in the fall of 2018.

II. Background

Since October 2014, Minnesota Power has operated a residential time-of-day (TOD) rate pilot, which included an on-peak period, an off-peak period, and a critical peak pricing (CPP) component. At its August 19th, 2018 meeting, the Minnesota Public Utilities Commission (Commission) approved Minnesota Power's request to end formal evaluation of the pilot program and asked the utility to file, by February 1, 2019, a set of recommendations for a new TOD rate design. The Commission also required Minnesota Power to conduct stakeholder engagement to inform the development of these recommendations.

In August 2018, Minnesota Power hired the Great Plains Institute (GPI) and the Center for Energy and Environment (CEE), co-conveners of the e21 Initiative, to design and conduct a stakeholder engagement process to solicit input on future TOD rate design recommendations. GPI and CEE worked with Minnesota Power to engage stakeholders across four meetings from September 2018 to January 2019. Minnesota Power also hired Navigant as a third-party technical expert to assist with developing rate design options. Staff from Navigant were present, either in-person or by phone, at all four meetings.

This document provides a summary of remarks by stakeholders at those four meetings. The notes do not indicate consensus among the group, but rather are meant to capture the collective discussion and key points raised by participants. No view should be attributed to any specific individual or organization that participated in the process. Importantly, the stakeholder engagement process and this resulting summary are intended to support, but not replace, important discussions within the formal regulatory process.

III. Process Overview

PROCESS OBJECTIVES

Co-facilitators GPI and CEE designed the stakeholder engagement process to achieve the following objectives, with input from Minnesota Power and in consideration of comments submitted in Docket No. E015/M-12-233 and made orally at the MN PUC meeting on August 19, 2018:

1. Better understand the context and parameters for an advanced TOD rate in Minnesota Power Territory, including:
    - Relevant results and conclusions from the recent Smart Grid Advanced Metering Infrastructure Pilot and TOD rate.
    - Status of metering and communications infrastructure, including current deployment of technology and planned timelines and projected costs for future deployment.
    - System load profile, associated costs, and generation mix at different times of day and year.
2. Develop shared objectives and design principles for an advanced TOD rate, building on those developed for Xcel Energy's TOU rate pilot, while recognizing key differences that are unique to Minnesota Power.
3. Identify recommendations for when, how, and at what scale an advanced TOD rate should be implemented (considering metering infrastructure and other factors).
4. Review and provide feedback on advanced TOU rate design options developed by Minnesota Power, using the objectives and design principles as a framework for evaluation.
5. Identify areas of agreement, disagreement, and desires for further inquiry among stakeholders to inform and support the formal regulatory process.

TIMELINE AND MEETING TOPICS:

The objectives listed above were broken down into four meetings that took place from September 2018 to January 2019, each covering the topics listed below. The process also included a break between Meetings 2 and 3 to allow Minnesota Power time to develop draft recommendations to be brought back to the group for review. Meetings were held in person in Minneapolis and Duluth, and by webinar as noted below.

Meeting 1: September 11, 2018 (Duluth, MN)

- Presentation from Minnesota Power and group discussion on current metering and communications infrastructure.
- Development of an initial list of shared objectives and design principles for an advanced residential TOD rate in Minnesota Power's service territory, including recommendations for when, how, and at what scale a TOD rate should be implemented.
- Identification of stakeholder questions pertaining to the recent Smart Grid Advanced Metering Infrastructure Pilot and TOD rate.

Meeting 2: September 28, 2018 (Minneapolis, MN)

- Presentation from Minnesota Power on system load profile, associated costs, and generation mix at different times of day and year.
- Presentation (as needed) from Minnesota Power and discussion on relevant results and conclusions from the recent Smart Grid Advanced Metering Infrastructure Pilot and TOD rate.
- Follow-ups from Minnesota Power with additional information on metering and communications infrastructure as needed.
- Refinement of objectives and design principles in consideration of Minnesota Power's metering infrastructure, load profile, and other factors.

BREAK: October-November 2018

- Minnesota Power developed rate design options and an implementation plan for the group to react to at the next meeting.
- Stakeholders reviewed information developed to date and provided additional thoughts as needed.

Meeting 3: December 10, 2018 (Minneapolis, MN)

- Presentation from Minnesota Power on draft TOD rate design options and implementation plan.
- Discussion of TOD rate design options and any areas of specific interest or concern, using objectives and design principles as a framework for evaluation.

Meeting 4: January 11, 2019 (Virtual Meeting)

- Presentation from Minnesota Power on refined TOD rate design options, responding to initial feedback.
- Identification of remaining areas of agreement, disagreement, and desires for further inquiry among stakeholders to inform and support the formal regulatory process.

STAKEHOLDERS

Together, GPI, CEE, and Minnesota Power developed a list of groups to invite to participate in this process that could offer a diversity of perspectives important to the development of a residential Time of Day rate, including all parties that had commented in Docket No. E015/M-12-233. Representatives from the following groups were invited to participate in this process:

- Citizens Utility Board of Minnesota
- City of Duluth
- Ecolibrium 3
- Energy CENTS Coalition
- Fresh Energy
- Minnesota Citizens Federation -- Northeast
- Minnesota Department of Commerce
- Minnesota Office of the Attorney General

The process benefitted from participation from some, but not all of these invited groups. In general, representatives from Citizens Utility Board, Fresh Energy, Department of Commerce, and the Office of the Attorney General were able to make all or most meetings. The City of Duluth and Ecolibrium 3 were able to attend some meetings. Energy CENTS Coalition and the Citizens Federation were not able to attend any meetings.

IV. Objectives of a TOD Rate

To guide the development of TOD rate recommendations, the group adopted the following two high-level objectives, which are meant to state the minimum benefits that a new TOD should deliver and accordingly, to serve as a threshold for determining whether a TOD rate makes sense compared to other possible strategies to achieve these objectives:

1. **Reduce system costs,** including consideration of peak demand, the need for future investments in the system, and other costs (e.g. market costs).
2. **Increase customer participation and satisfaction,** with participation loosely defined as the number of customers actively reducing their on-peak load, and satisfaction based at least partly on the opportunity to reduce costs.

V. Design Principles

To provide further guidance, the group developed, and iteratively refined over the course of the four meetings, the following nine design principles. The idea of these principles was that if a TOD rate successfully achieved each of these, then the group would likely be able to support it. Importantly, these were meant to be taken as a package (i.e., stakeholders may not have supported each of these principles on their own, but found the full set acceptable. Adherence to a single principle could have unintended consequences without the others providing balance).

Moreover, the principles were sorted into two lists—six “must-have” principles and three “nice-to-have” principles—based on stakeholder input in an online survey. The differentiation between “must-have" and "nice-to-have" was simply meant to provide a sense of priority since the list was long. The principles are listed below, along with commentary that arose during discussions of each principle.

MUST-HAVE DESIGN PRINCIPLES (TO BE TAKEN AS A PACKAGE):

1. **Provide an evaluation of the costs and the benefits of the TOD program.**

   The benefits of a new TOD rate, including reduced system costs and the opportunity to reduce bills through behavior change, should outweigh the costs, including customer education, marketing, and administration. However, participants acknowledged that the benefits may be difficult to measure and that some of the costs of implementing a TOD rate, such as metering, may be shared with other initiatives outside of the rate itself. Moreover, the group understood that a full evaluation of costs and benefits would not be possible until the point of a complete filing for a new rate.

2. **Include considerations for indemnifying low-income customers.**

   Impacts on low-income customers were a common concern throughout stakeholder discussions, though it was not clear whether the bill impacts of proposed TOD rate designs were significant enough to warrant indemnification for low-income customers. Minnesota Power offered to look further into this. Participants stated that at minimum they'd like to see a transition plan that can indemnify initial impacts of a TOD rate on low-income customers, while allowing them the opportunity to save money on bills as a result of behavior change.

   Defining low-income customers was also raised as a concern, but not fully addressed in these meetings as the Commission had taken up the issue in other dockets. The concern, which has been raised for other utilities in Minnesota as well, is that low-income customers are often defined based on participation in LIHEAP—a definition that leaves out many customers who are eligible for LIHEAP assistance but not actively participating in the program.

3. **Enable energy conservation, cost-effective integration of additional renewables, and reduction of GHG emissions.**

   Stakeholders agreed that a successful TOD rate should seek to reduce energy usage and greenhouse gas emissions while enabling the cost-effective integration of additional renewable generation. At the conclusion of the four meetings, the group was satisfied that the rate options presented by Minnesota Power would meet this principle. However, several participants agreed that a more forward-looking analysis of system peak, taking into account additional renewable generation expected to come online in future years, would improve the rate design.

4. **Provide rates that accurately reflect the cost to serve, both now and looking forward.**

   Minnesota Power has a very unique load profile, which is relatively flat throughout the year and over the course of a day due to a large industrial load. Residential load, which is the target of potential TOD rate designs, makes up only 10% of gross load. As a result, stakeholders asked Minnesota Power to assess the best approach for linking a TOD rate to costs in a way that would meet this principle while enabling a price differential between time periods that would incent customers to shift usage from on-peak to off-peak periods. In response, the company presented a series of options for cost allocation and associated rate designs. As noted below, the group came to rough consensus on one of these options, which allocated embedded costs to different time periods based on the load that caused those costs.

5. Consider using an opt-out approach for the base TOD rate.

One key decision in designing a time-varying rate is whether to automatically assign customers onto the rate and allow them to "opt-out" if they wish, or to encourage customers to "opt-in." Research has shown that opt-out rate designs tend to be more cost-effective because they have lower marketing costs to achieve high levels of participation. Group members had varying opinions on whether the rate should be opt-out or not. Some participants favored an opt-out design because it would place all customers on a time-varying rate, increasing the rate's impact; others, in keeping with Design Principle 1, wanted Minnesota Power to weigh the costs and benefits of an opt-out approach and determine whether it would be appropriate. For this reason, the group asked Minnesota Power to consider an "opt-out" design but did not require it as part of this principle.

Additionally, the group discussed that Minnesota Power could deploy a base TOD rate with an "opt-out" approach, and then offer additional "opt-in" components, such as critical peak pricing or a peak time rebate that would allow customers additional opportunities to reduce bills in return for shifting loads during times of peak usage.

6. Give customers adequate tools to access and understand their usage data.

While some group members felt this was a "must-have" principle, it wasn't discussed at length in meetings because it applied to a level of detail beyond the scope of the initial rate design options being developed. If and when a new rate offering is fully developed, group members stated that they'd like the offering to provide a strong interface for customers to access usage data, as well as co-marketing of efficiency programs and technologies that can help with responding to a time-varying rate. Additionally, the group noted that the recently completed TOD rate pilot could help inform the most effective approaches to achieve this principle.

NICE-TO-HAVE DESIGN PRINCIPLES:

1. Balance precision and practicality, both for the utility and for customers.

While no group member felt this was a "must have" principle, some participants did state that it's important to set timeframes that are not significantly disruptive to customers. To achieve this, it could be helpful to understand the extent to which customers can and cannot shift load to affect system peak. Since Minnesota Power is a winter-peaking utility in a northern climate, customers with electric space heating were of particular concern.

Additionally, some stakeholders were concerned about how a TOD rate would interact with existing customer programs such as CARE and Budget Billing, while also acknowledging that it's important to include as many customers (or customer types) as possible in a TOD rate offering.

2. Design within the parameters of the revenue requirement.

There was discussion among the group about whether a TOD rate would be revenue-neutral, which would be challenging given that Minnesota Power does not have a decoupled rate structure. For that reason, the group suggested that any TOD rate should be designed within the parameters of the revenue requirement.

3. **Evaluate options to layer products on top of base TOD rate, considering what drives demand at peak (CPP, PTR, BDR).**

Products layered on top of a TOD rate could include incentives or disincentives for reducing load during critical events. These could include "critical peak pricing," in which electricity prices increase dramatically during critical events, "peak time rebate," in which customers receive a monetary reward for reducing usage (but are not assessed a penalty if they don't respond), or "behavioral demand response," in which customers are given positive, but non-monetary feedback (e.g., via a thank-you message) in return for reducing load during critical events in response to a request from the utility.

The group was open to Minnesota Power exploring these options and did not feel strongly for or against their inclusion. As noted above, the group suggested that additional products could be optional under an "opt-in" program design, even if a TOD rate was set as the standard rate for all residential customers.

VI. Technology and Timing

In the group's first meeting in September 2018, Minnesota Power staff presented on the current state of the utility's metering and communications infrastructure, as well as plans for future investments in new technology. One of the key findings from this presentation was that Minnesota Power has deployed Advanced Metering Infrastructure (AMI) meters to roughly half of its residential customers, but it doesn't currently have a Meter Data Management (MDM) system to collect and process the data produced by those meters. Without an MDM, utility staff have to manually address any billing errors — a laborious process that would make widespread use of AMI meters uneconomical.

Minnesota Power is in the process of acquiring the needed MDM system, but it likely won't be fully operational until 2022. For this reason, stakeholders thought that a phased approach to deploying a new TOD rate, like the one described below, would make sense. This would allow Minnesota Power to test, learn, and scale a new rate design over time and in accordance with the implementation timeline of the MDM system. Importantly, there was not consensus on a specific phased deployment plan for a TOD rate. The plan described below is just an example of how a phased deployment could be implemented to align with the timeline of the new MDM system:

SAMPLE PHASED DEPLOYMENT PLAN

Phase 1: Before MDM is in place (expected 2019-2020)

- Use this as a planning and preparation period, as the benefits of a TOD rate likely wouldn't justify the resources needed to manually fix billing errors without an MDM.
- Identify a suitable rate design, then look at how to deploy it.
- Conduct strategic planning around leveraging related programs to maximize the benefit of a TOD rate (e.g., energy efficiency programs).

Phase 2: MDM implementation period (expected 2020-2021: 1-year implementation + 1-year stabilization)

- This time period allows a long "runway" during which Minnesota Power can test (see examples below) and prepare for a broader rollout of a TOD rate.
- Test the new rate with some customers (e.g., current pilot participants and/or EV owners) and do shadow billing for all other customers to identify which customers will need the most help, then develop targeted programs to help those customers.
- Possibly test some specific technology or customer segments (e.g., opt-in for EV owners).

Phase 3: Post-MDM implementation, continued AMI deployment (2022-2025)

- Roll-out the new TOD rate over time to all applicable customers as AMI meters are deployed.

Phase 4: Full AMI deployment with MDM operational (2025+)

- AMI meters and TOD rate are fully deployed to all applicable customers.

Additionally, stakeholders discussed that the following considerations could be addressed in early phases of deployment to ensure a successful full-scale rollout. The group felt that these were important to consider but did not have time to discuss them at length. Moreover, some of these may have already been addressed, in part, by Minnesota Power's now concluded Smart Grid Investment Pilot.

CONSIDERATIONS FOR EARLY PHASES OF DEPLOYMENT:

1. **Identify which practices are effective at shifting customer load**, including the peak to off-peak ratios, duration of peaks, and timing of peaks that will send an adequate price signal to customers while accomplishing other state goals.
2. **Identify what outreach and education methods are most effective for different customer segments** (including who is the best messenger).
3. **Understand ramifications for particular customer segments**, with attention to low-income customers, including how much money customer groups saved or lost, how specific practices increased or decreased customer participation and satisfaction, and to what extent customers had the ability to respond. Identify exclusions/issues with specific customer groups and plan for bringing them into the TOD rate (considering phased deployment).
4. **Understand how a TOU rate might enable demand response** (e.g., through critical peak pricing or critical time of day pricing).
5. **Identify what value is provided by different technology options** (e.g., pre-programmed thermostats).
6. **Understand how other customer interventions can be paired with TOU rates and how this affects cost-effectiveness** (e.g., energy efficiency programs).

VII. Rate Design Options

The order from the Commission required Minnesota Power to develop "alternative rate designs" rather than a fully developed TOD rate. To support a robust stakeholder discussion on this topic, Minnesota Power presented six different rate design options to the group at its third meeting in December 2018. These options reflect the possible combinations of three different ways of allocating costs (in accordance with Design Principle 4) and two different approaches to setting peak periods based on an analysis of Minnesota Power's load profile.

The group provided in-depth feedback in response to these six initial options, which Minnesota Power took into account to develop and present a refined set of options in Meeting 4. Below, we have summarized the key discussion points during these meetings. A complete listing of all feedback received is included in the notes from the individual meetings, which are attached to this summary.

FEEDBACK IN RESPONSE TO RATE DESIGN OPTIONS:

Overall approach

- Creating multiple rate design options based on varying cost allocation and peak period design decisions was comprehensive and helpful for figuring out the best possible solution given Minnesota Power's unique load profile.
- The general design (though varying depending on the specific option) seemed simple and likely to benefit most customers.

Cost allocation

- Among the three cost allocation options presented in Meeting 3, stakeholders said they preferred "Option A," which allocated embedded costs across time periods based on the load that caused those costs. After Meeting 3, all refined options that were presented in Meeting 4 were based on this cost allocation method.

Peak period design and impact on pricing

- Three TOD periods (peak, off-peak, and super off-peak) appeared to enable a better customer response compared to the two-period (plus critical peak pricing) design of the recently concluded TOD pilot rate.
- Pricing for the three periods seemed justified based on underlying costs, in accordance with Design Principle 4. However, there was concern among stakeholders that the price difference between on-peak and off-peak periods was not enough to elicit a strong response from customers. Some stakeholders were interested in seeing how slight differences in the peak period design (e.g., increase or decrease the peak period by an hour, change the allocation of the peak period across months of the year, or both) would impact pricing levels to achieve a bigger differential between the peak and super off-peak periods. Minnesota Power made these changes after Meeting 3 and presented them for feedback in Meeting 4, at which point

stakeholders said they preferred the three following options, with some preferring one over the other, but all saying they could probably support one of these three if the benefits were found to outweigh the costs:

  - A four-hour peak that is in place year-round but shifts two hours earlier in the day during the summer months to better accommodate the summer peak.
  - A five-hour peak that is consistent throughout the year.
  - A four-hour peak that only occurs during the summer and winter (i.e., there would be no peak period, leaving only two periods—super off-peak and off-peak period —in April–June and September–October).

Analysis of future generation mix and load profile

- Since the analysis of Minnesota Power's load profile was based on their last resource plan, some stakeholders said they would like to have seen a more forward-looking analysis (e.g., forecasting to 2030) that would consider additional renewable energy generation expected to come online in future years. Participants were specifically interested in whether this might increase the differential between on-peak and off-peak pricing, making the price signals stronger and thereby eliciting a better response from customers.
- Some participants also thought a more forward-looking analysis would make the TOD rate design more accurate at the time of deployment, given the need to wait until the MDM system is fully operational.

Inclusions/exclusions

- There were several questions about whether and how specific customer types might be included in or excluded from this rate. These were not fully resolved in meetings and would need to be addressed in the process of developing a complete rate design offering. The following customer groups were specifically discussed:
  - Electric space heating customers—Minnesota Power is a winter peaking utility, with the peak caused primarily by both primary and supplemental electric space heating, as well as low penetration of air conditioning (which keeps the summer peak lower than other utilities, creating a winter peak). The group noted that this would be important to consider in designing a future TOD rate. Notably, Minnesota Power already has a dual fuel rate that is interruptible in the case of a peak event, which may help inform whether and how to include these customers.
  - Net metering customers—while including net metering customers in a time-varying rates presents some billing challenges, some stakeholders expressed the expectation that these customers should be included, especially if the utility is proposing investment and cost recovery in new metering and an MDM system to help with accurate billing. Minnesota Power estimated that there are currently about 200

customers on a net metering rate and offered to look into how metering and billing could work for these customers under a TOD rate.

- Multi-family building tenants—some stakeholders wanted to know how a TOD rate would apply to customers in multi-family buildings where there are multiple tenants on a single meter.

Effect on Inverted Block Rate

- Minnesota Power currently has an inverted block rate (IBR) for residential customers, in which customers with higher usage pay a higher rate. Multiple stakeholders were interested to know how a TOD rate would impact the existing IBR, including whether the IBR would discontinue in favor of a new TOD rate, if one is developed and deployed. However, there was disagreement on this. Some thought a TOD rate was more favorable because it could integrate additional renewables, support beneficial electrification, and be paired with more effective ways of incentivizing energy conservation (one of the primary goals of an IBR). Others thought that switching from an IBR to a TOD rate could potentially be more costly for the same general benefits, or have adverse impacts on low-usage customers who are currently benefitting from the IBR. Evaluating the impacts of the IBR, including customer benefits, in the process of weighing costs and benefits for a potential TOD rate will help to address this.
- Participants were also particularly interested in how the shift from IBR to a new TOD rate would affect low-income customers.
- One stakeholder commented that if the customer benefit between the IBR and TOD are roughly even, then more consideration should be given to outreach and roll-out of the TOD to ensure smooth implementation so that the benefits can be realized cost-effectively. In other words, effective implementation will be required to enable the benefits of switching from IBR to TOD.

Customer impacts and engagement

- At least one participant thought it would be helpful for Minnesota Power to develop “user profiles” representing different customer types to illustrate how, under each rate design option, customers would be impacted. As noted under Design Principle 2, low-income customers were of significant interest to multiple stakeholders.
- Given the potential for a TOD rate design in which the peak period changes throughout the year, some participants were concerned about the ability of customers to understand the rate design. However, Minnesota Power staff noted that the recently concluded pilot TOD rate was quite complicated, including a critical peak pricing component, and customers showed a strong understanding of the rate in surveys. In response, stakeholders seemed satisfied that Minnesota Power could appropriately educate customers but were still interested in evaluating an education and engagement plan when a new TOD rate is fully developed.

Weighing benefits and costs

- At the conclusion of Meeting 4, multiple stakeholders remarked that they were appreciative of Minnesota Power's genuine attempts to develop TOD rate design options in response to stakeholder input. All participants said that they could probably support one of the three options described above, but would need more information to make a final determination.

VIII. Conclusion

Overall, participants in this process were appreciative of Minnesota Power's genuine efforts to collaborate with stakeholders in the development of new TOD rate design options. Over the course of four meetings, the group came to better understand Minnesota Power's load profile, metering and communications infrastructure, and experience from the recently concluded TOD rate pilot. It became clear that if a future TOD rate is deployed, the timing will need to align with the deployment of a new Meter Data Management system that is expected to be fully operational by 2022. Given this timing constraint, a phased approach to rolling out a new TOD rate may make the most sense.

To support the development of any new TOD rate design, stakeholders developed high-level objectives and a set of more detailed design principles, which Minnesota Power used to develop a series of analysis-based rate design options for the group to review. While stakeholders thought that there were at least three resulting rate design options that could potentially meet the group's objectives and design principles, there was significant interest in evaluating the specific details of any proposed TOD rate to assess costs and benefits. Importantly, the two "Objectives of a TOD Rate" that the group agreed to—reducing system costs and increasing customer participation and satisfaction—can provide a useful rule of thumb for evaluating a new TOD rate, both independently and against other possible options to achieve those same objectives. Moreover, the "must-have" and "nice-to-have" design principles can provide guidance for the development of a new, fully developed TOD rate if doing so is found to be advantageous.

GPI and CEE thank the stakeholders who provided input for their time and effort throughout this process.

Appendix

Table of Contents

Minnesota Power Advanced Time-of-Day Rate

Meeting 1: September 11th, 2018

Great Lakes Aquarium
353 Harbor Dr, Duluth, MN 55802

1:00pm – 4:00pm

Remote Access Link: https://betterenergy.zoom.us/j/799394140
Dial: +1 646 876 9923 or +1 669 900 6833
Meeting ID: 799 394 140

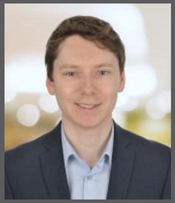
Agenda

1:00-1:10pm	Welcome, Intro's, Process Overview
1:10-1:20pm	Brief Context for Time-Varying Rates (Lon Huber, Navigant)
1:20-2:00pm	Shared Objectives and Design Principles- Part 1 (For TOD rate itself)
2:00- 2:45pm	Current Metering and Communications Infrastructure (Minnesota Power Staff)
2:45-3:00pm	BREAK
3:00-3:30pm	Shared Objectives and Design Principles- Part 2 (For rollout of TOD rate – when, how, at what scale)
3:30-3:50pm	Identifying Key Questions
3:50-4:00pm	Reflection, Wrap-up, and Next Steps
4:00pm	ADJOURN

TIME VARYING RATES FOR RESIDENTIAL CUSTOMERS

A BRIEF PRIMER

SEPTEMBER 2018



Lon Huber
Director

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NAVIGANT'S GLOBAL ENERGY PRACTICE

We collaborate with clients to help them thrive in a rapidly changing environment.

CLIENTS

- ✓ 50 largest electric and gas utilities
- ✓ International, federal, and state governments
- ✓ 20 largest independent power generators and gas distribution and pipeline companies
- ✓ Leading oil & gas companies
- ✓ Multiple new energy market entrants and investors

TEAM

- ✓ Industry's largest energy management consulting team
- ✓ Consultants average 15 years of experience
- ✓ 60% have an advanced degree
- ✓ Over 50% have an engineering degree

NAME

- ✓ Among Top 10 in Vault's 2017 Best Consulting Firms for Energy
- ✓ Named "Best Advisory – Renewable Energy" in 9th and 10th Annual Environmental Finance and Carbon Finance Market Surveys

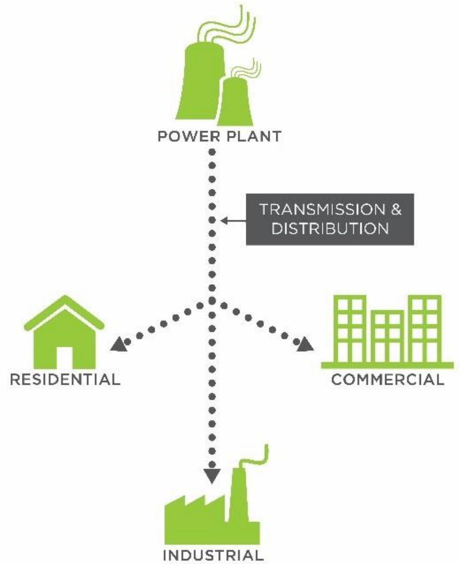
RESIDENTIAL TOU RATES TODAY

- 14% of all US utilities offer a residential TOU; roughly half of IOUs offer one
- Where TOU is available, around 3% of customers are enrolled on average
- 74% of TOU rates have only two pricing periods
- 71% of TOU rates have a price ratio of at least 2-to-1
    - Half of TOU rates have a price differential of at least 10 cents/kWh
- Of the utilities offering TOU rates, roughly half offer more than one TOU option

Source: The National Landscape of Residential TOU Rates – Brattle Nov 2017

ENERGY TRANSITION: *TRENDING TOWARD A CLEAN, DECENTRALIZED, INTELLIGENT & MOBILE GRID*

PAST: Traditional Power Grid
Central, One-Way Power System

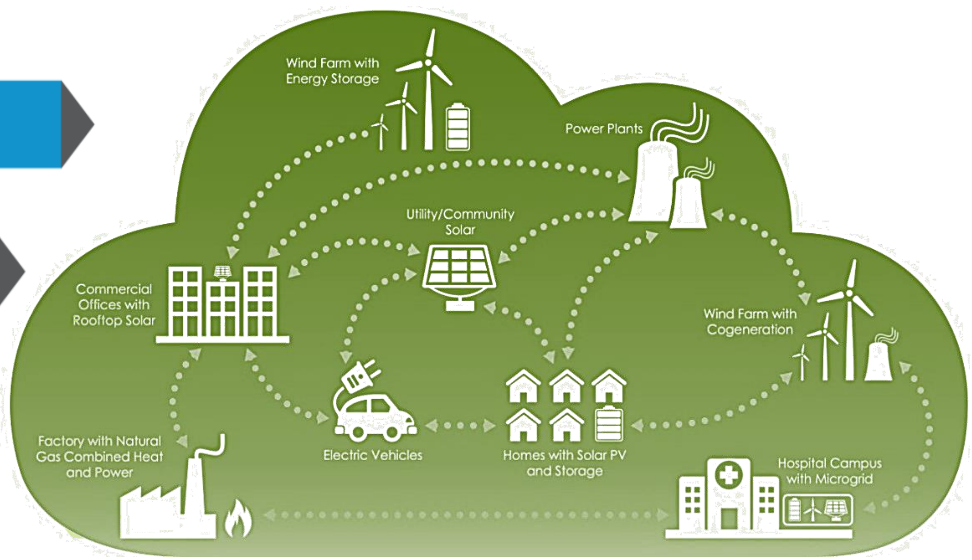


Market Demand

Technology Innovation

Policy & Regulation

TODAY: The Energy Cloud
Distributed, Cleaner, Two-Way Power Flows



2025

- 746 GW wind[1]
- 668 GW distributed solar
- 144 GW distributed DR
- 62 GW distributed energy storage
- 3.5 GW C&I microgrid capacity
- 22.3m EVs battery-powered
- >5 billion residential IoT

Source: Navigant 2017

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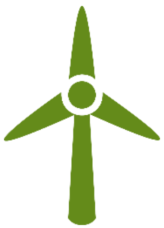
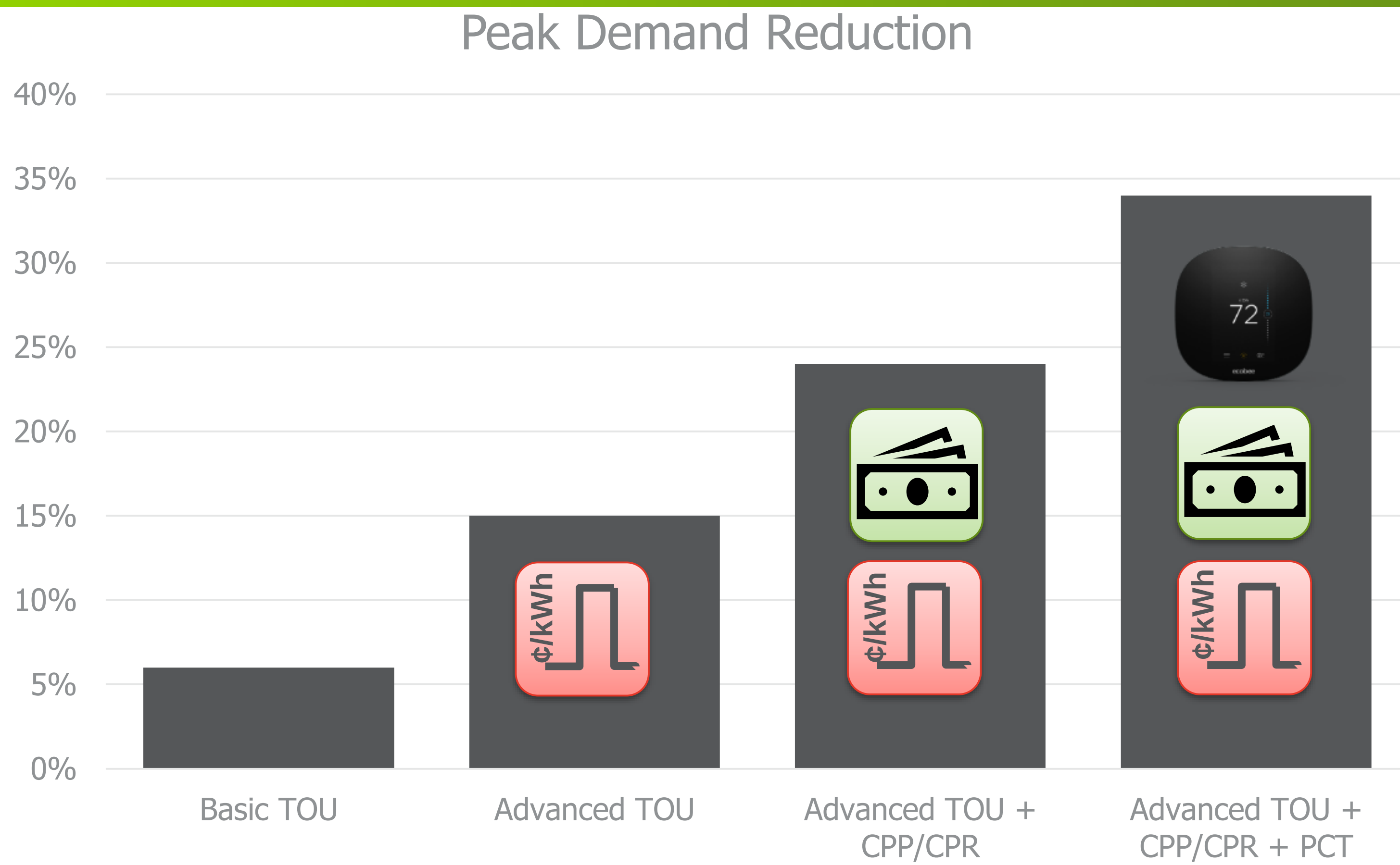
RESIDENTIAL TOU RATES TOMORROW

1. Three or more time periods
2. A focus on capacity rather than energy
3. Shorter time windows from the traditional 10+ hour peak windows
4. Link to low marginal cost hours
5. Better enrollment methods



DEMAND REDUCTION POTENTIAL



The goal is to turn passive customers into active customers

Source: Strategen and U.S. DOE, November 2016, Final Report on Customer Acceptance, Retention, and Response to Time-Based Rates from the Consumer Behavior Studies, https://www.smartgrid.gov/document/CBS_Results_Time_Based_Rate_Studies.html

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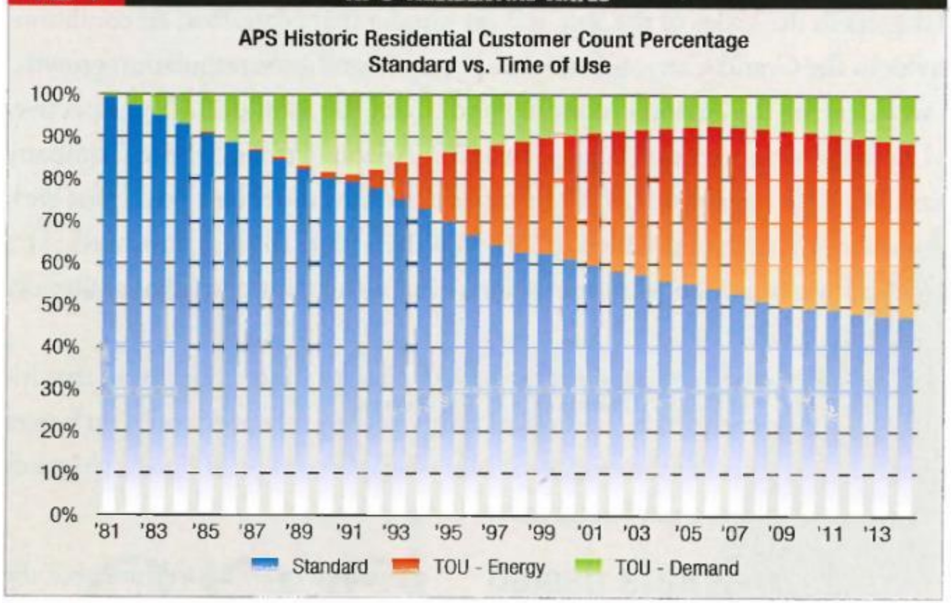
CUSTOMERS ARE HAPPY WITH TIME VARYING RATES OVER THE LONG RUN

- Began offering Time of Use rates in 1982
- Well marketed and advertised
- 568,500 residential customers on time differentiated rates
- ~50% opt-in Time of Use rates

FIG. 1 APS RESIDENTIAL RATES



Source: Strategen/Xcel and APS 2015 Demand Side Management Annual Progress Report
There and Back Again, Fortnightly November 2015

CONTACTS

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Lon.Huber@Navigant.com

navigant.com

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AMI System Deployment and Future Technology for Time of Day

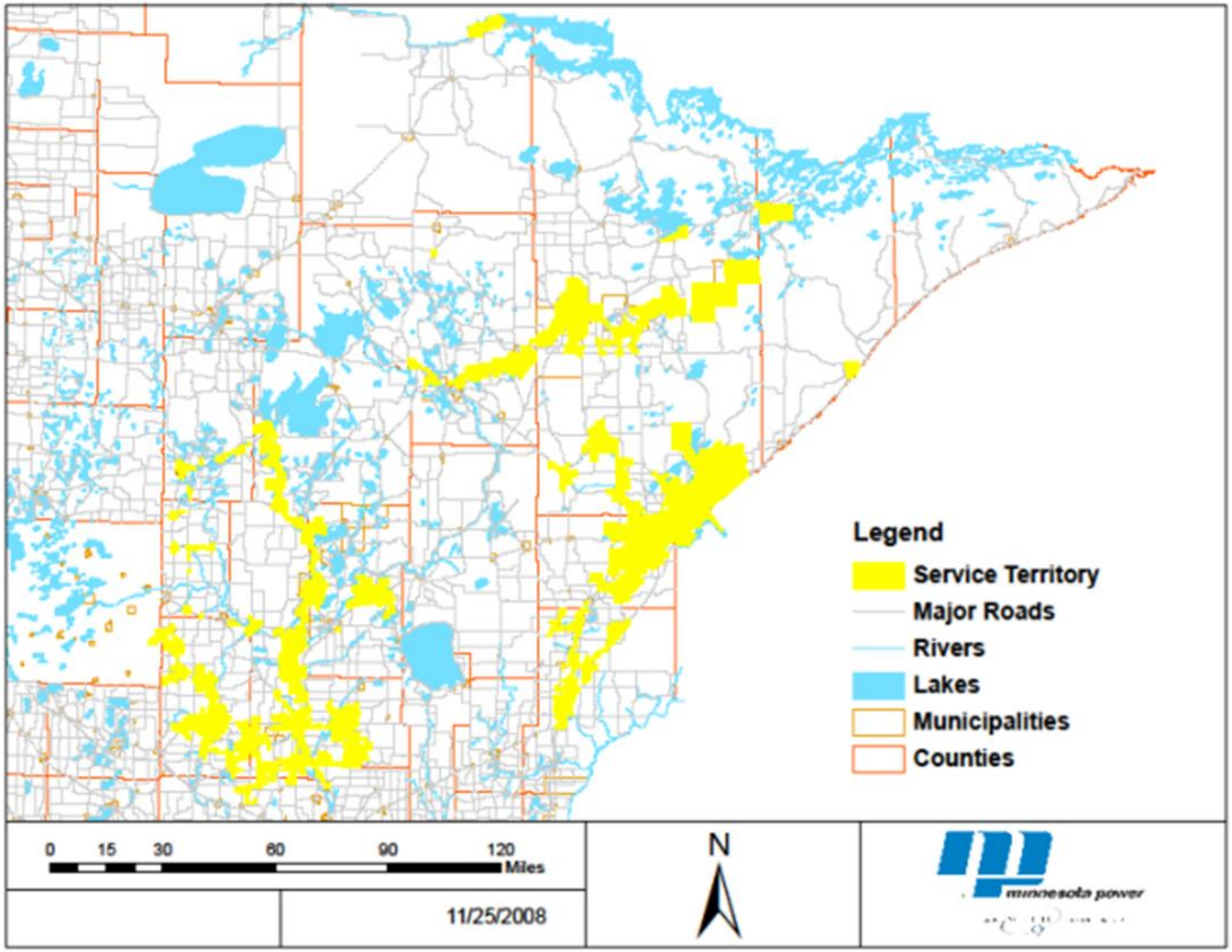
Daniel Gunderson, P.E.
Distribution Engineering & Operations

Overview

- Minnesota Power Info
- AMI System Architecture & Overview – Sensus FlexNet
- Current Deployment of the System
- Current Time of Day Pilot Program
- Technology Roadmap

Minnesota Power Service Territory

- Customers: 144,000
- Peak Load: 1970MW
- Distribution: 6200 Feeder Miles
- Transmission: 2500 Line Miles



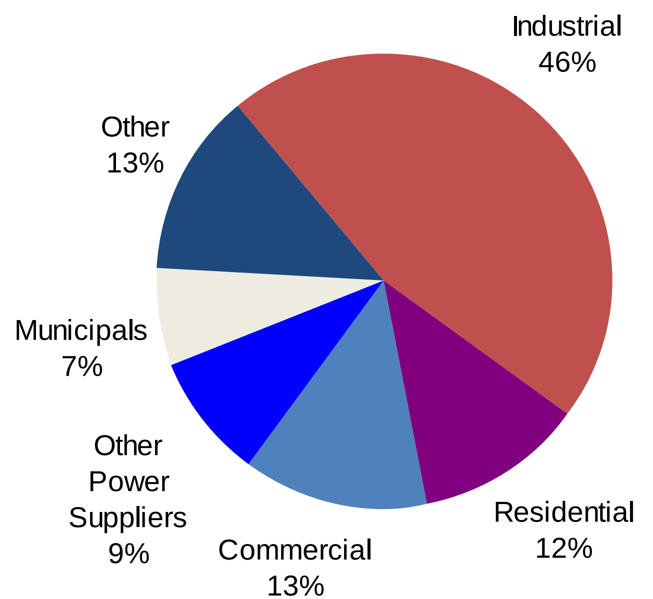
At a Glance

- Large industrial customer class

ArcelorMittal BOISE CLIFFS Steel Dynamics, Inc. USS MESABI NUGGET NewPage sappi

- Generation and purchased power of 1900 MW

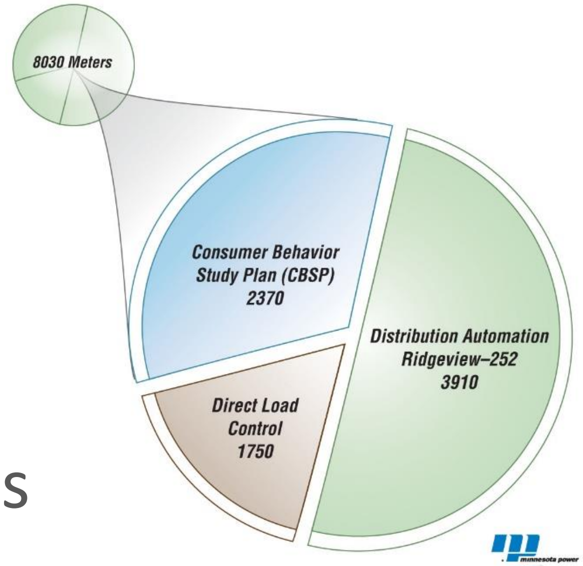
- Service territory includes some of the world's largest known reserves of taconite, copper-nickel, and other precious metals



Regulated Utility Revenue
(6/30/12)

DOE Smart Grid Investment Grant

- Project Dates – May 2010 – December 2014
- Time of Day Pilot through September 2015 (still going)
- Total Project Budget – $3,088,000
- 12/31/2014 - ~$3.5M Actuals
- 100% Deployment Completion
- Meters Deployed: 8030 of 8030
- Review of Four Major Project Areas
  - Dual Fuel – Load Control Upgrade
  - Outage Management System and Distribution Automation (OMS & DA) Smart Feeders Project
  - Meter Data Warehouse
  - Consumer Behavior Study & Critical Peak Pricing Project (TOD)



System Selection

- System Selection was done by AMI/CPP Team
- Analyzed 15 different Vendor Products for AMI System
- Power Line Carrier (PLC), Mesh & Mesh Hybrid Networks, Tower Technologies were all part of the Analysis
- Sensus FlexNet was selected based on the functionality of the system and the complimentary nature to MP's existing assets

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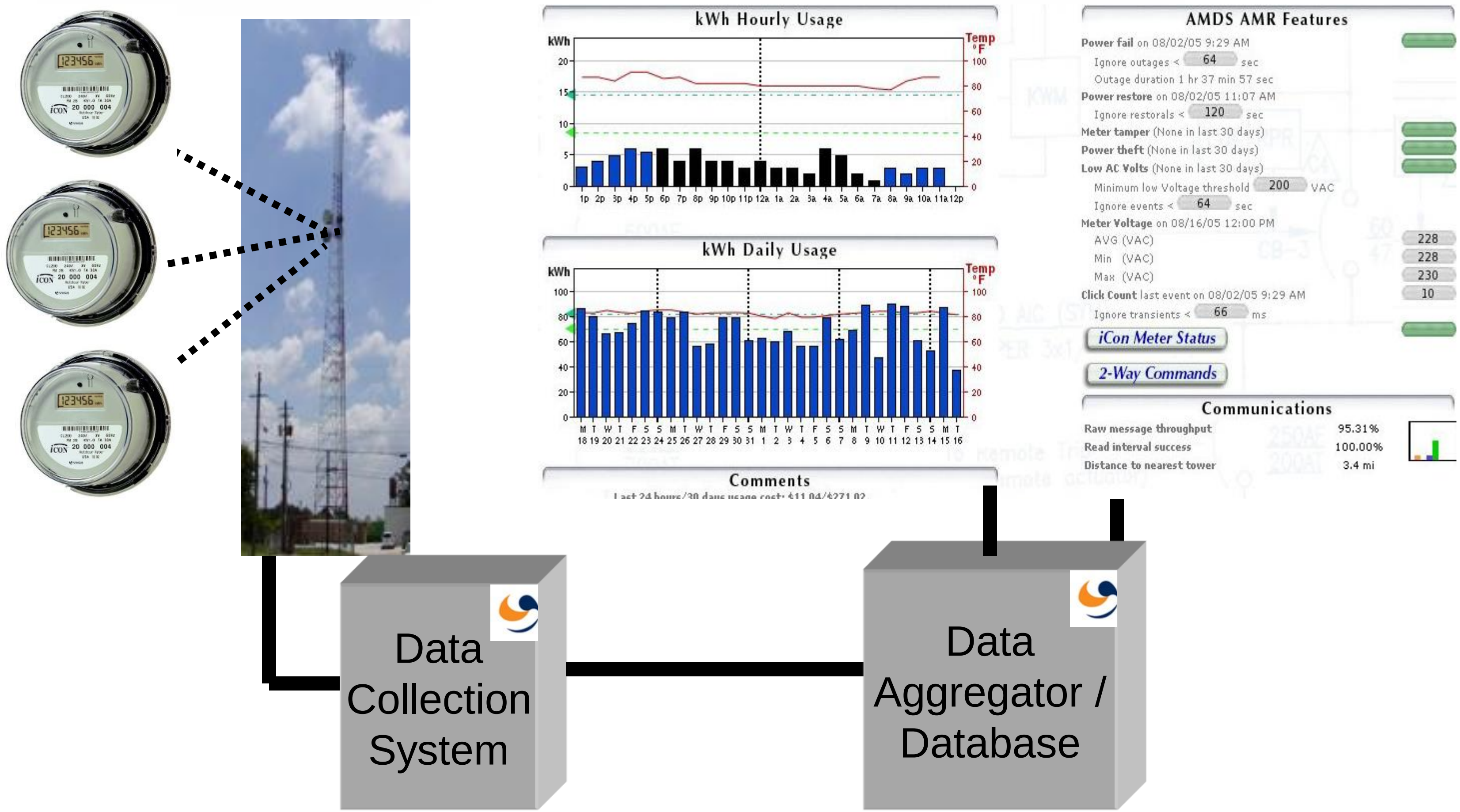
AMI System Overview



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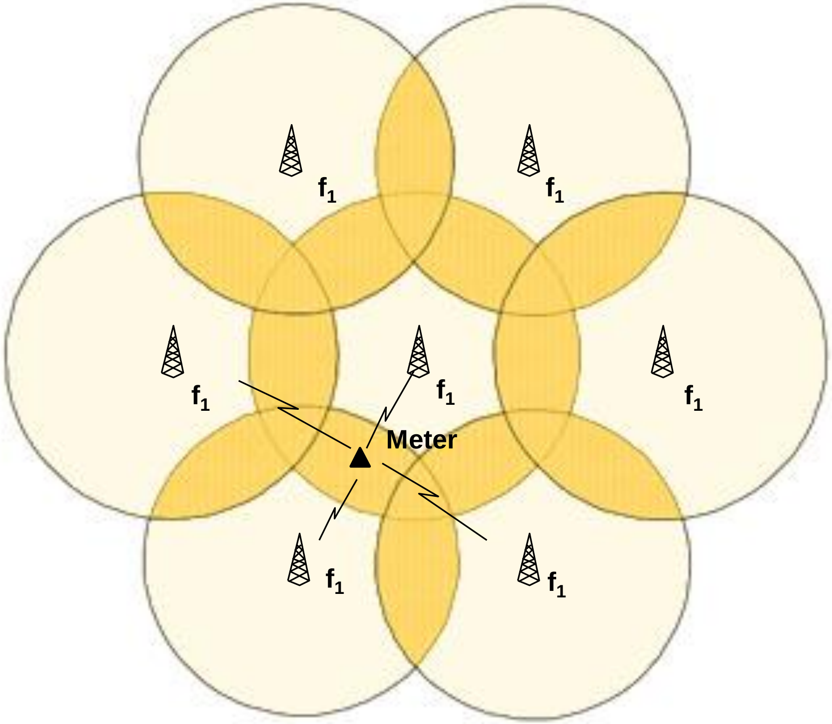
System Overview Cont'd…

- Tower Coverage's Ideally provide 50% Overlap with Adjacent Cells
- Creates Significant Signal Redundancy
- Single "Hop" Architecture for Mesh Network Between Meters

FlexNet



Provides Redundant Overlapping Coverage

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Meter TOD Capability

- Meter Overview:
  - Up to 7 TOU Tiers
  - Up to 8 Seasons
  - Up to 24 holidays
  - Critical Peak Pricing (CPP) Dynamic Response

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Current Time-of-Day Offering

- On-Peak 8a-10p M-F/Off-Peak 10p-8a M-F + Weekends + Holidays
- Critical Peak Pricing
  - determined by market prices
  - Assumed at 25hr/yr
  - Capped at 50hr/yr
- Closed Pilot (400/660 participants remain)
- Much more detail in Docket No. E015/M-12-233

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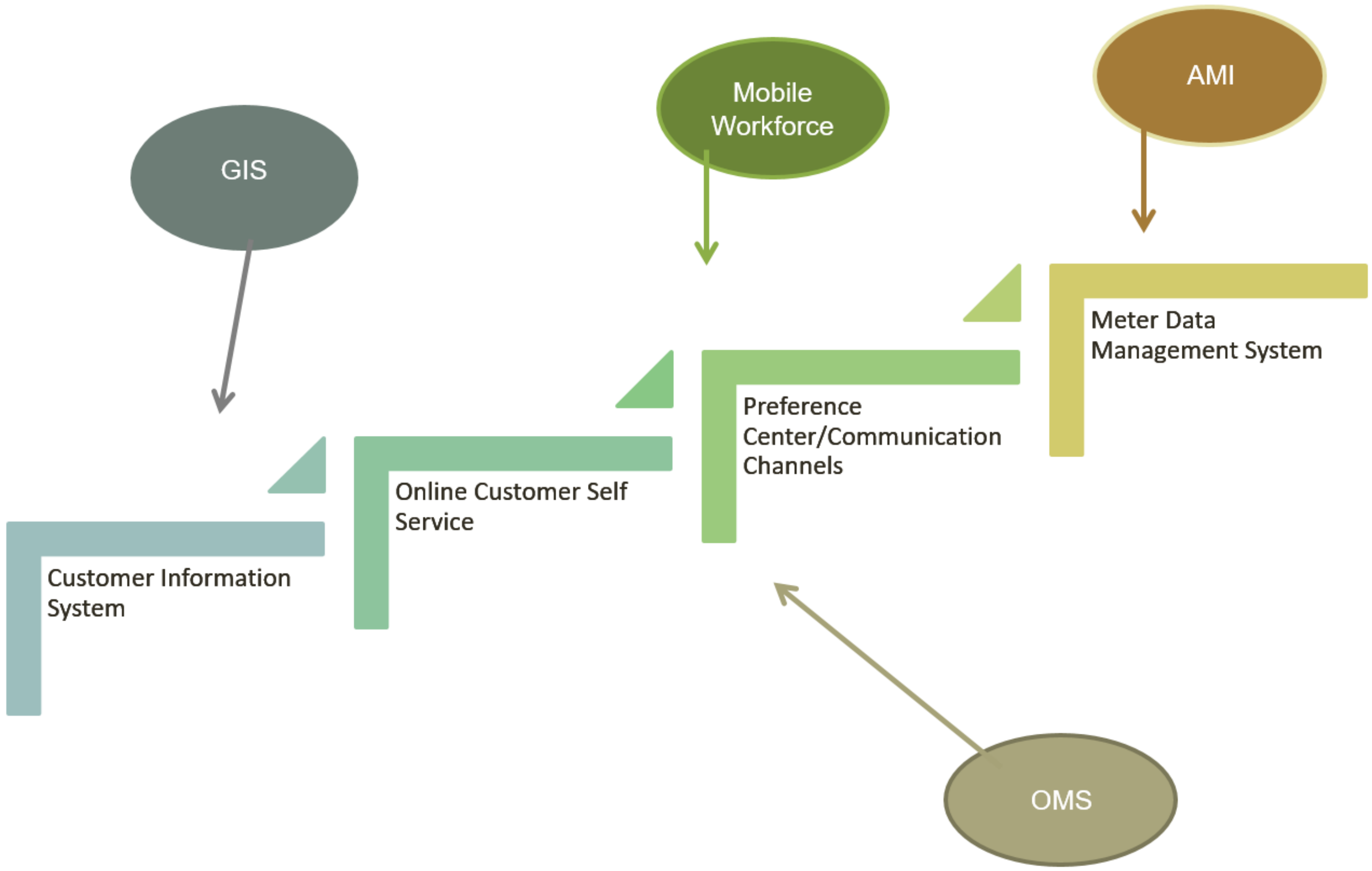
Deployed with Plans for Future Enhancements

- Meter Data Management System
- Evaluate Other Alternative Rates
- Enhanced Revenue Protection
- Power Quality Monitoring
- Pilot Reporting Reliability Statistics (By Point)
- Demand Response

Technology & Data Integration



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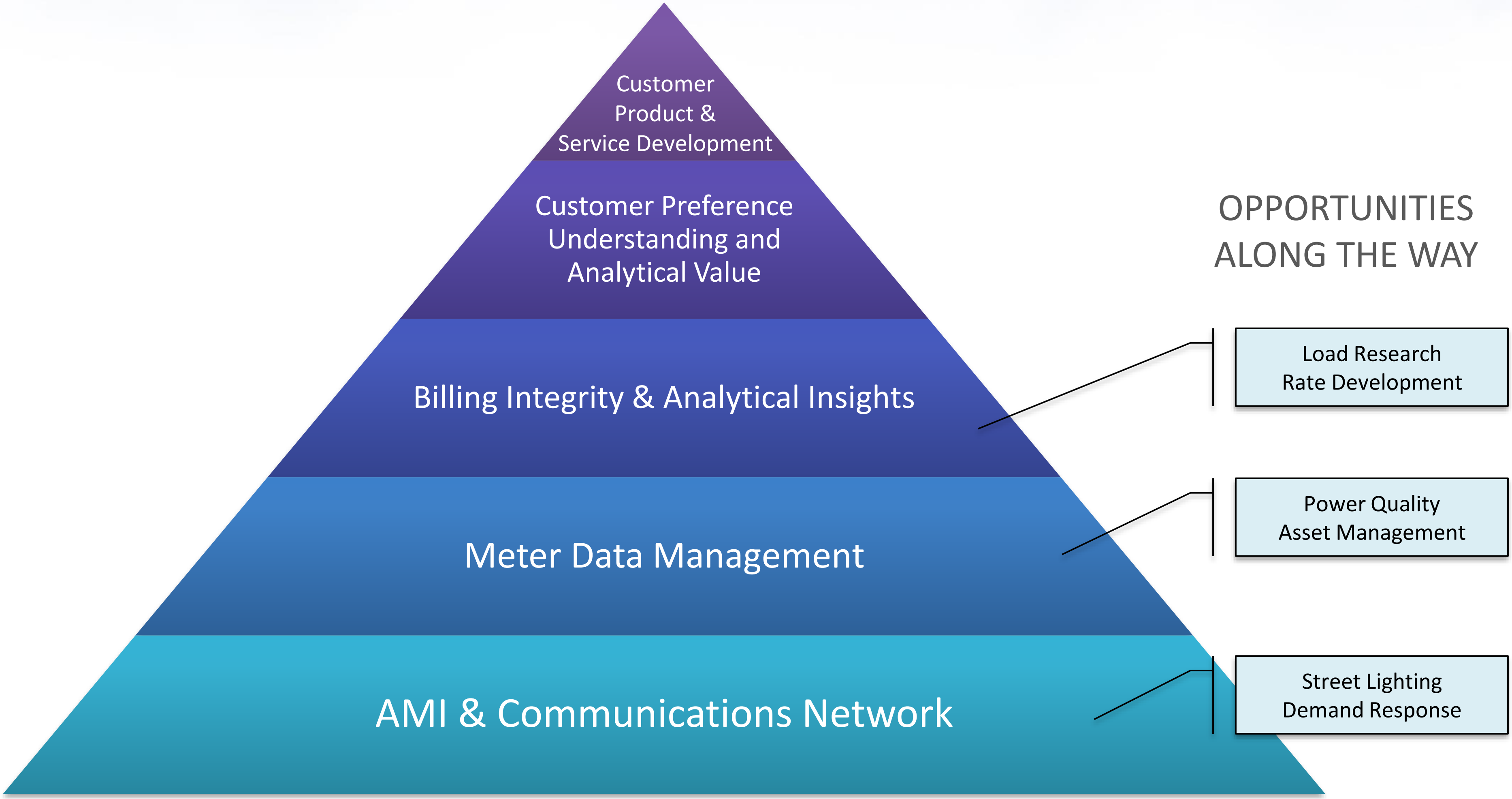
Current State – Need for MDM

- Validation, Estimation and Editing (VEE) of meter data
  - CIS are not designed to process, analyze or store mass volumes of data received from AMI
  - Interval data – up to 1,000,000 rows of data and only 50% deployed
  - Analysis
- Automation of meter alarm actions
- Enables complex billing and rates, including TOD
  - ~25% of current TOD customers require manual billing intervention
- Manage mass amounts of AMI meter data (5, 15, 60 minute interval data)
- Improves customer's view of their consumption through MyAccount
- Load analysis
- Power quality analysis
- Aggregation of meter data
- Demand Response flexibility

Benefits of an MDM

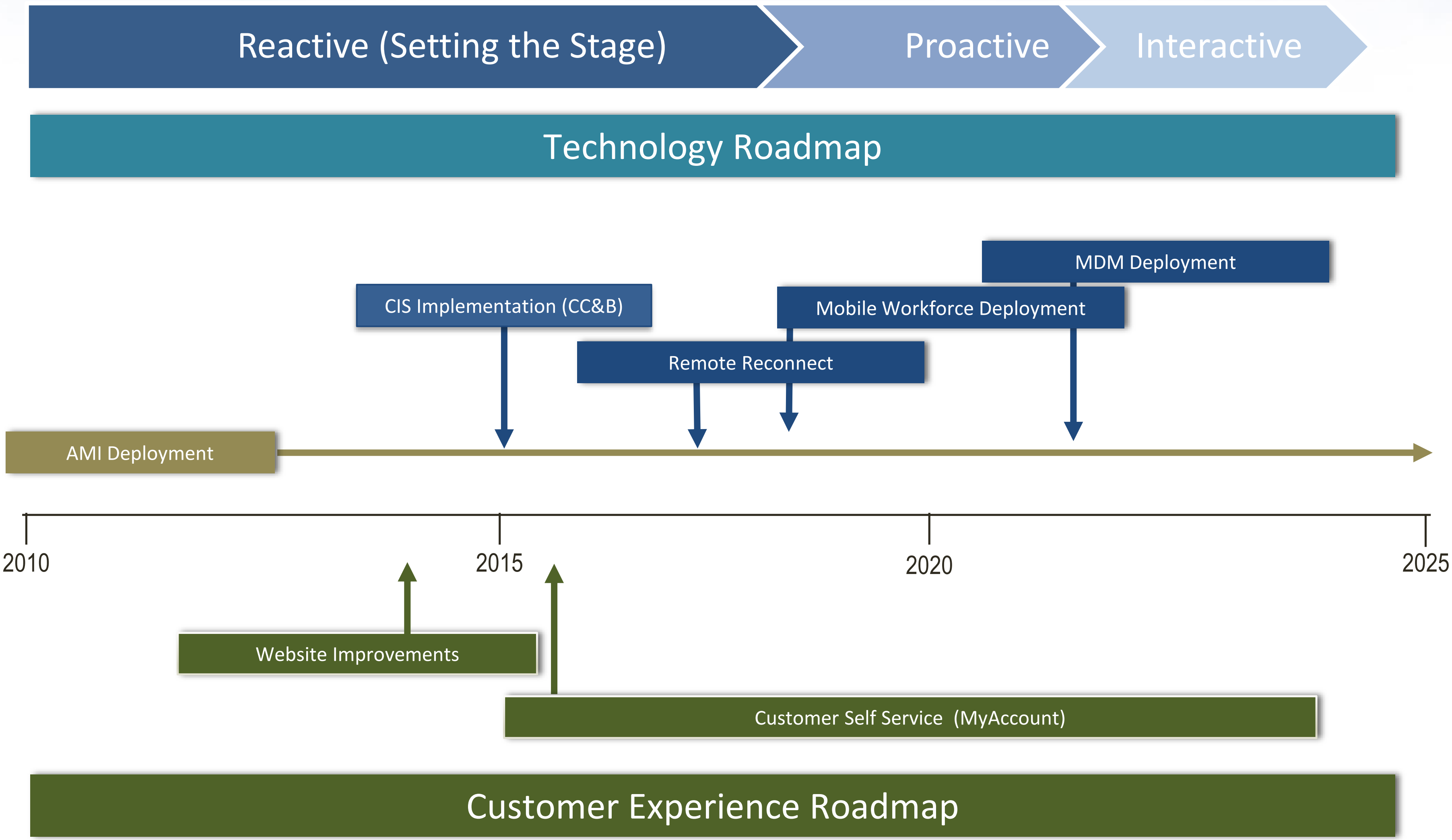
- Improved ability to investigate meter and service anomalies using events and alarms
- Improved power quality detection
- Better visibility of load data from aggregated meters
- Increase ability to identify and take action on meter failures and theft
- Increase integration with Outage Systems to reduce outage duration, increase accuracy of estimated restoration times, and reduce repeated customer calls to verify power status
- Facilitate access to business data and reporting
- Promote data-driven decision-making
- Establish and improve analytics
- Improved validation

Integration with Distribution System Platform



Attachment A

Roadmap and Timeline



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Questions?

Minnesota Power Advanced Time of Day Rate
Meeting 2: September 28th, 2018

Mill City Museum – ADM Room
710 S 2nd Street, Minneapolis, MN 55401

9:00am – 12:30pm

For remote meeting access, please click this link at the meeting time:
https://betterenergy.zoom.us/j/275325095

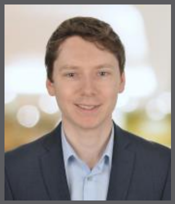
Note: for optimal audio quality, we suggest using headphones or a headset

Draft Agenda

9:00-9:15am	Welcome, Intro's, Recap from Meeting 1
9:15-9:30am	Review Objectives and Design Principles
9:30-10:30am	Presentation: System Load Characteristics
10:30-10:45am	BREAK
10:45-11:15am	Presentation: Findings from Smart Grid Pilot
11:15-12:15pm	Discussion: Objectives, Design Principles, Roll-out Plan
12:15-12:30pm	Reflection, Wrap-up, and Next Steps
12:30pm	ADJOURN

MINNESOTA POWER SYSTEM LOAD CHARACTERISTICS

SEPTEMBER 28, 2018



Lon Huber
Director

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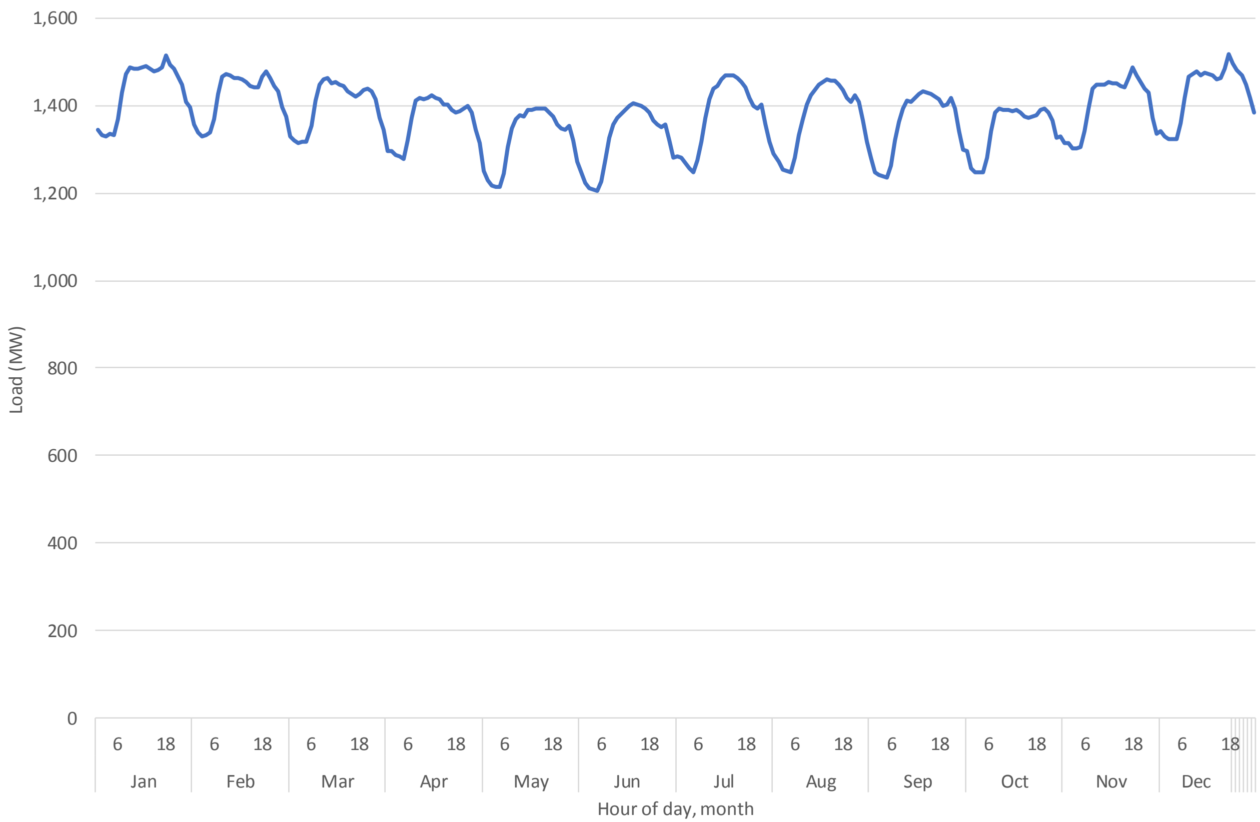
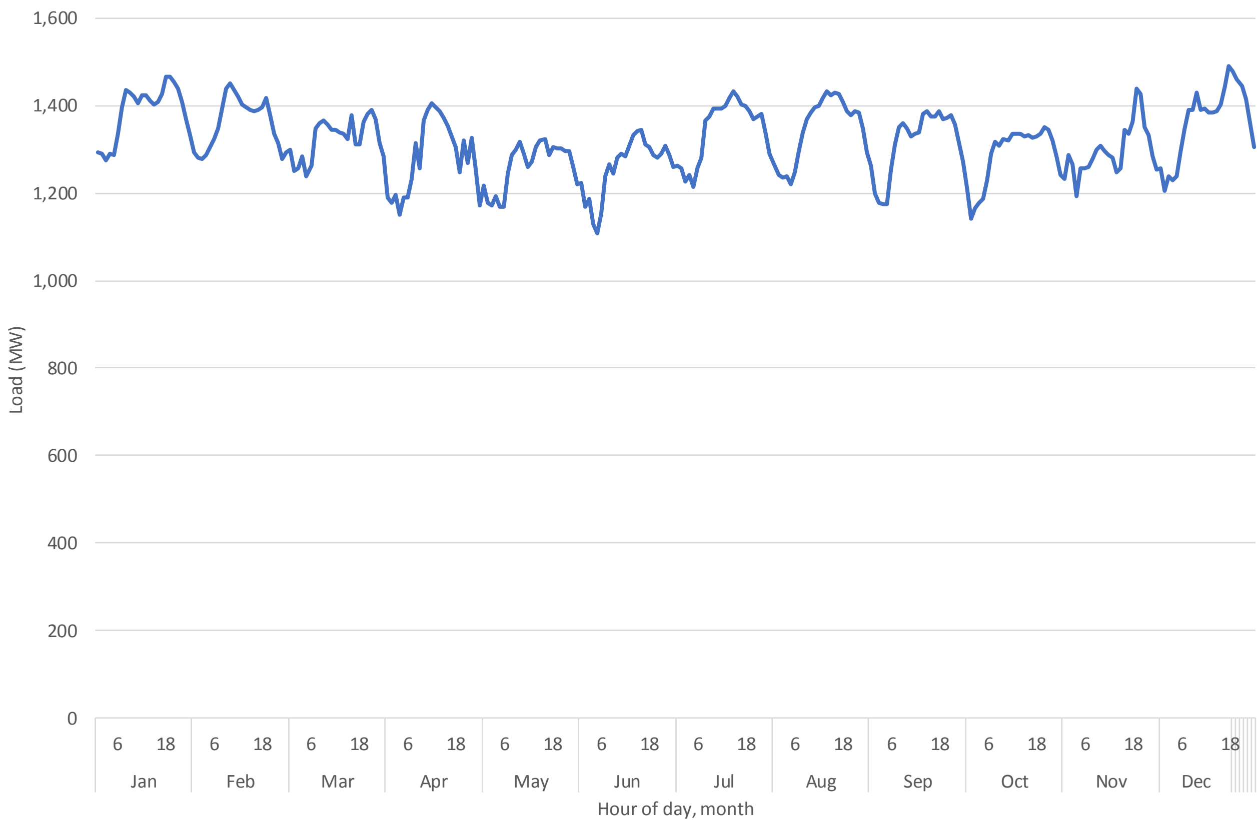
GROSS SYSTEM PEAK LOAD
BY TIME OF DAY AND MONTH - 2020



- Load is relatively flat across the year and across the day when compared with other utilities, driven by high share of large industrial load
- 74% industrial
- Peak in winter, with summer higher than shoulder seasons
- Average gross load is equal to 89% of peak gross load

NAVIGANT

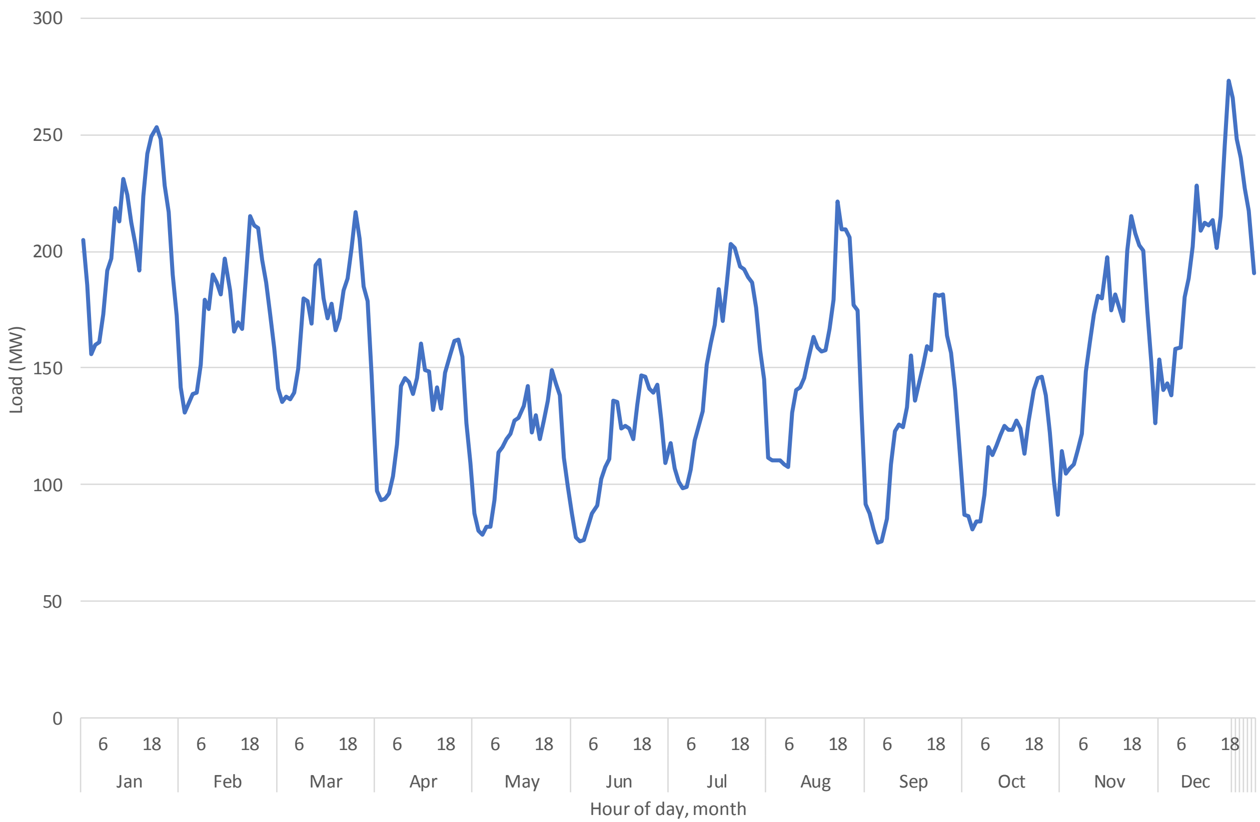
NET SYSTEM PEAK LOAD*
BY TIME OF DAY AND MONTH - 2020



- More variability than gross load, but still relatively flat
- Includes planned additions of renewable generation

- Net load is gross load less wind and solar generation
- The Minnesota Renewable Energy Standard requires public utilities (other than Xcel) to obtain 21.5% of their energy from renewable energy sources by 2020 rising to 26.5% in 2025 (including a 1.5% solar carve out in all years)

RESIDENTIAL PEAK LOAD BY TIME OF DAY AND MONTH - 2020



- Residential load shows much more variability than system load, both within a day and between seasons
- Strong winter evening peak
- Average residential load is equal to 51% of peak residential load

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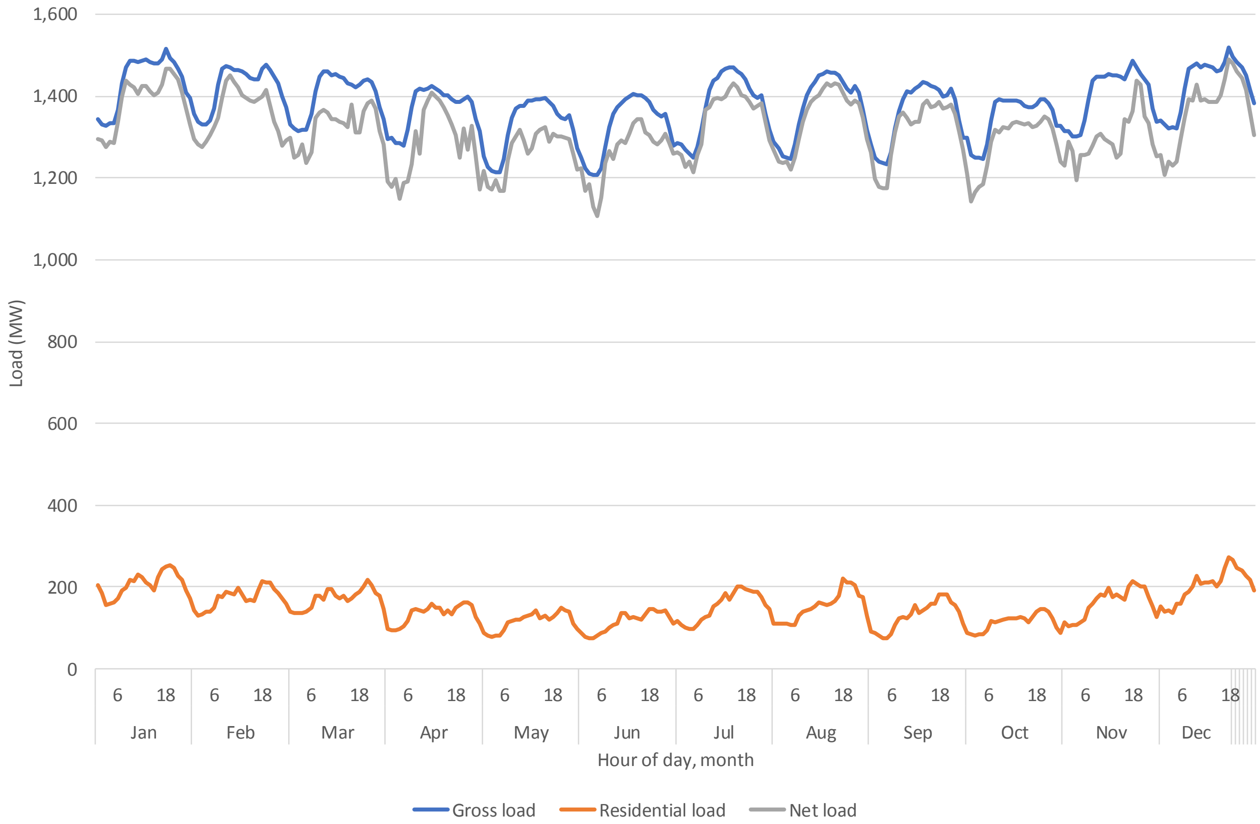
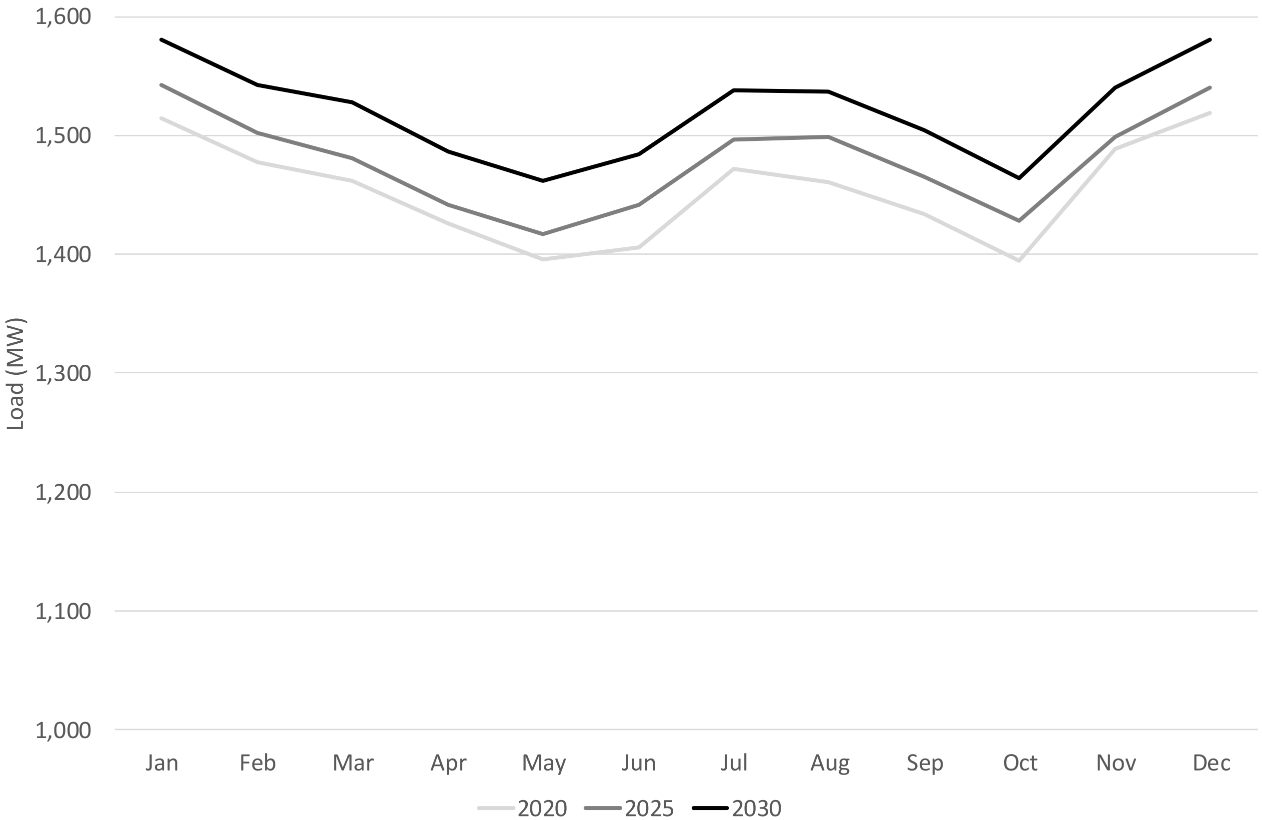
PEAK LOAD
BY TIME OF DAY AND MONTH - 2020



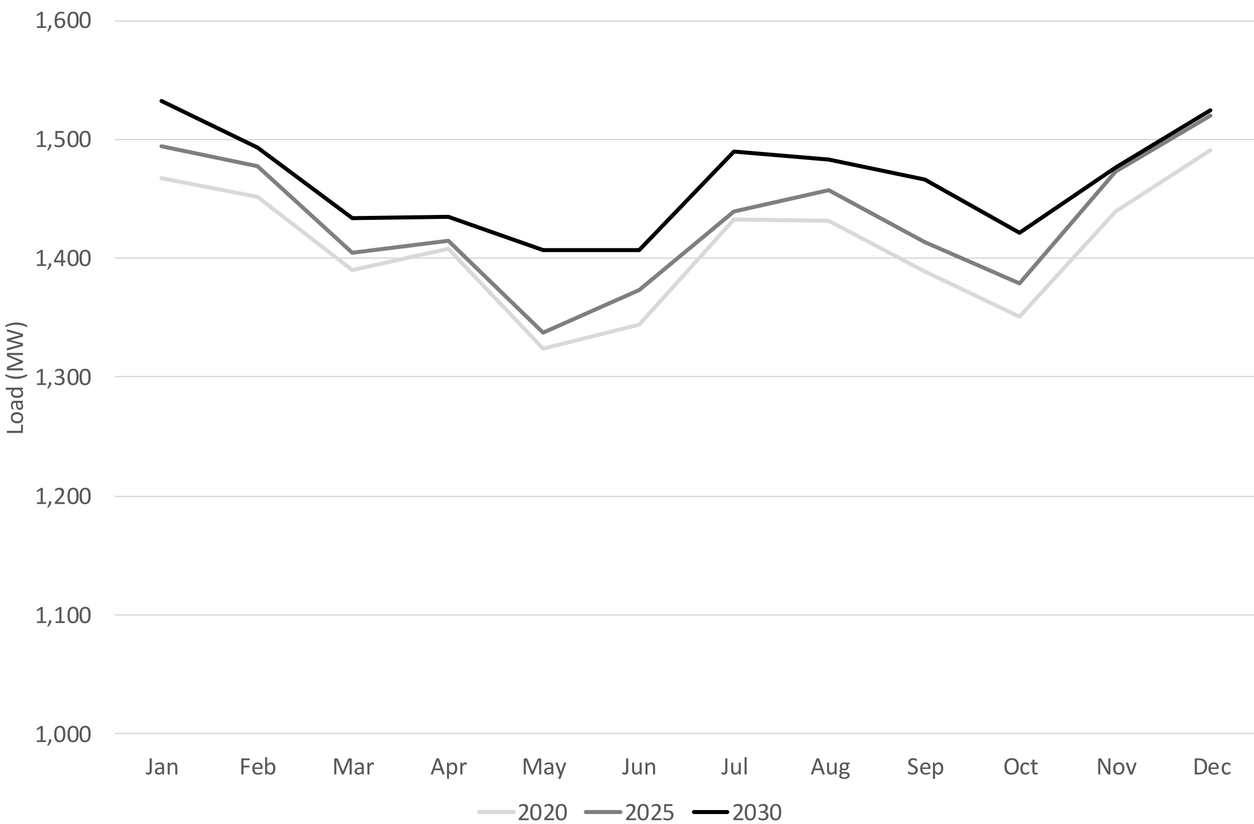
- Residential load makes up less than 10% of gross load, a small share when compared with other utilities

PROJECTED SYSTEM PEAK GROSS LOAD BY MONTH



- 4% peak growth projected from 2020 to 2030 for both winter and summer peaks

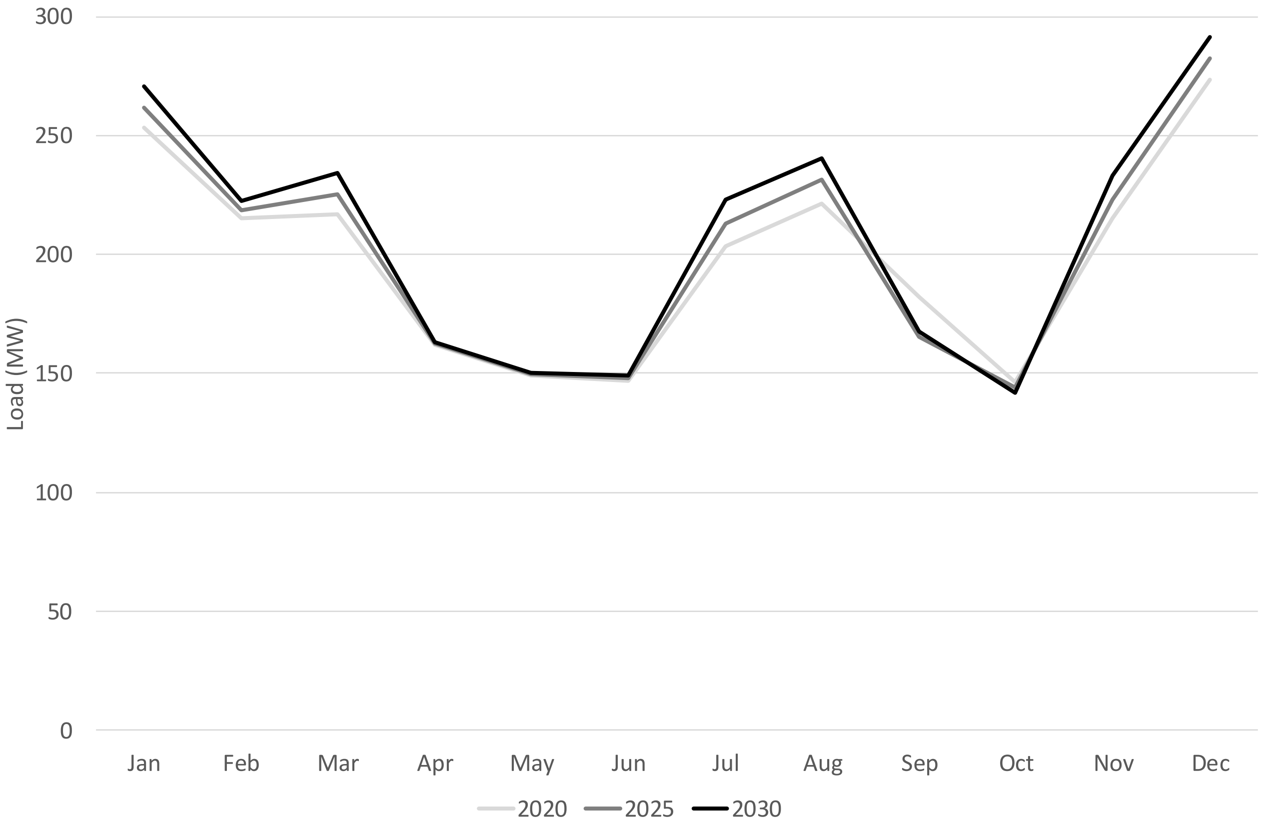
PROJECTED SYSTEM PEAK NET LOAD* BY MONTH



- Peak net load projected to drop in the short term and then return to 2017 level by 2030
- Short-term drop driven by growth in wind and solar generation
- Flat growth within error range

* Net load is gross load less wind and solar generation

PROJECTED PEAK RESIDENTIAL LOAD BY MONTH



- 7% (20 MW) peak growth projected from 2020 to 2030

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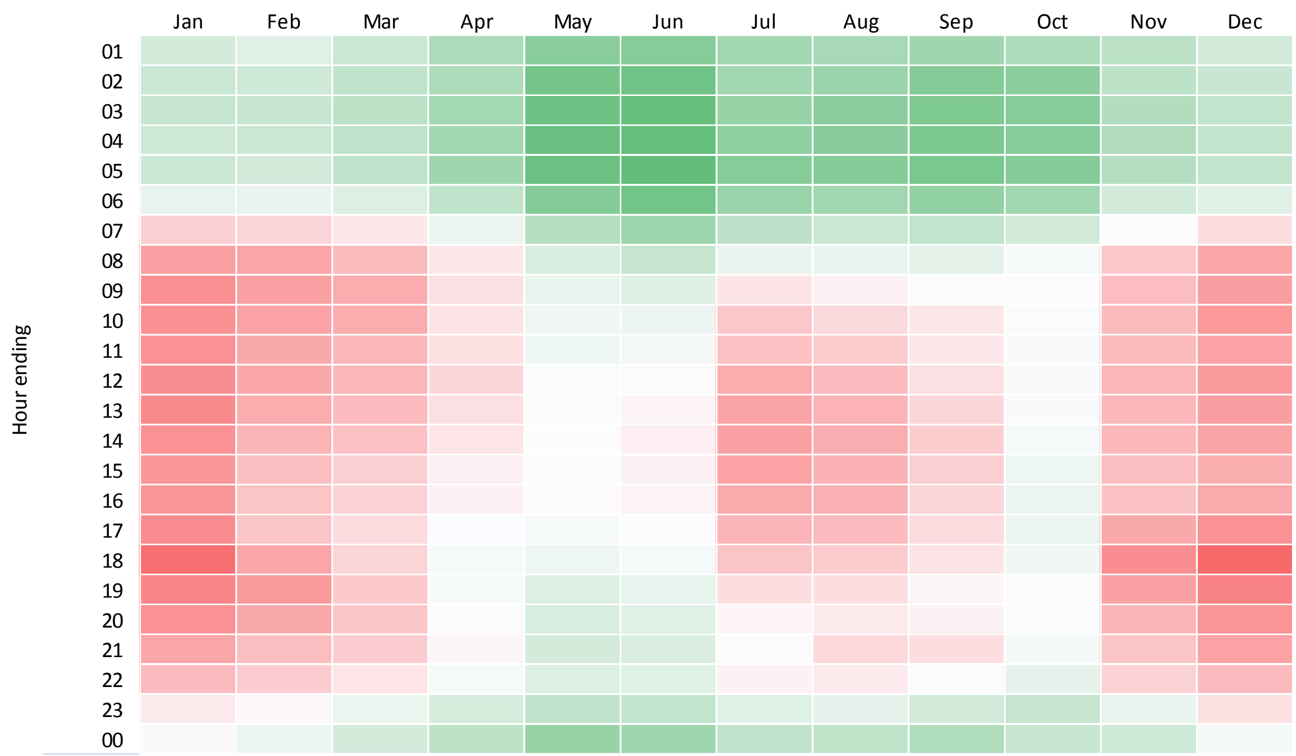
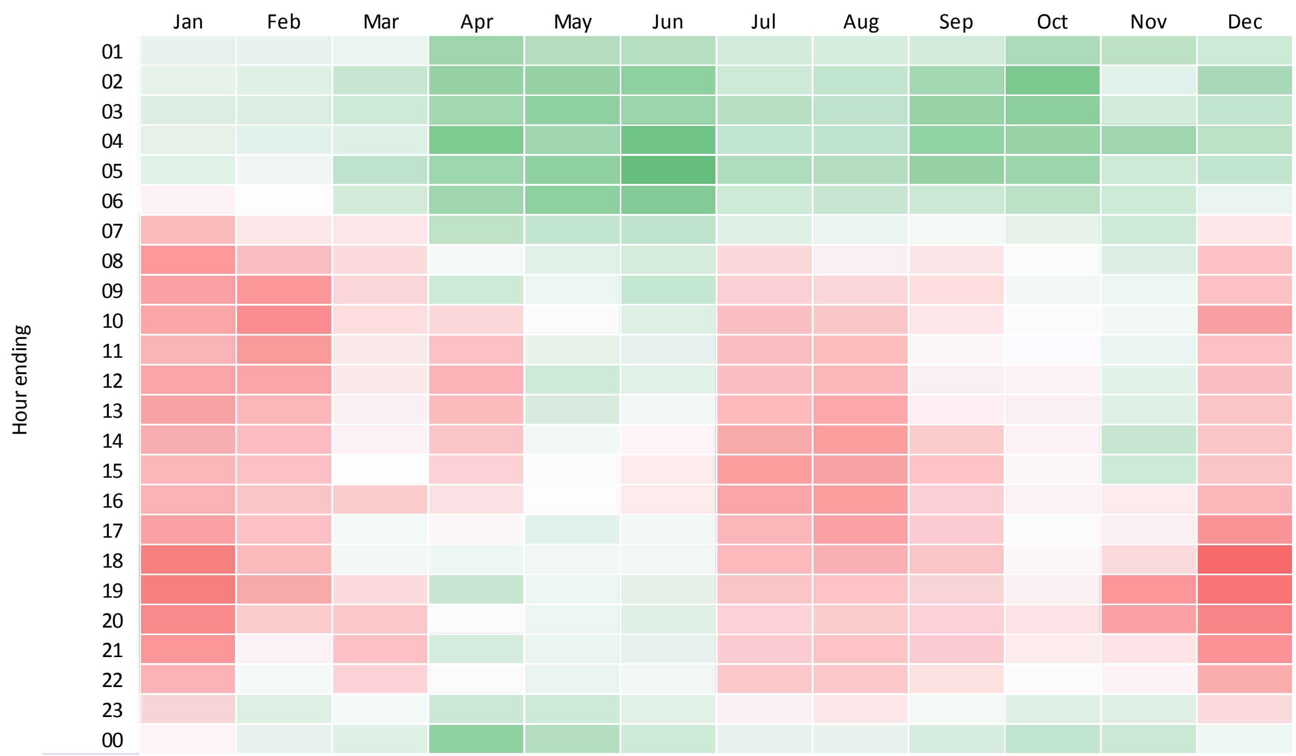
GROSS SYSTEM LOAD HEAT MAP - 2020



- Seasonal and day/night patterns
- Load highest on winter days
- Low load overnight
- Generally lower load in shoulder seasons (spring, fall)
- Range 1,150 MW – 1,550 MW

Red – high load, green – low load

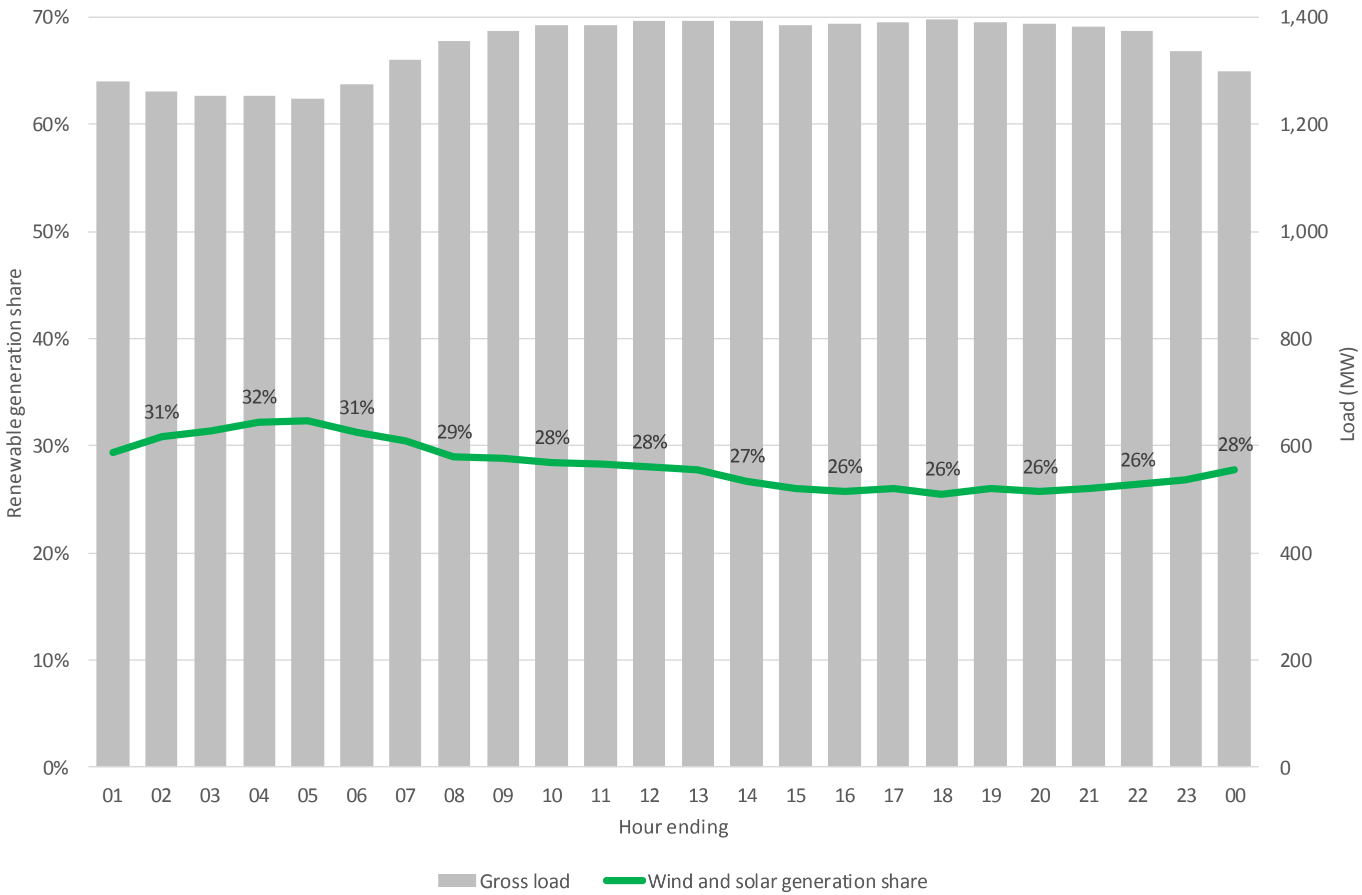
NET SYSTEM LOAD HEAT MAP - 2020



- Similar pattern to gross load (with more variability)
- Seasonal and day/night patterns
- Net load highest on summer and winter days
- Low load overnight
- Generally lower load in shoulder seasons (spring, fall)
- Range 350 MW – 1,500 MW

Red – high load, green – low load

RENEWABLE SHARE OF GENERATION IS HIGHEST OVERNIGHT



- The Minnesota Renewable Energy Standard requires public utilities (other than Xcel) to obtain 21.5% of their energy from renewable energy sources by 2020 rising to 26.5% in 2025 (including a 1.5% solar carve out in all years)
- Data is average projected load and renewable generation by hour for 2020

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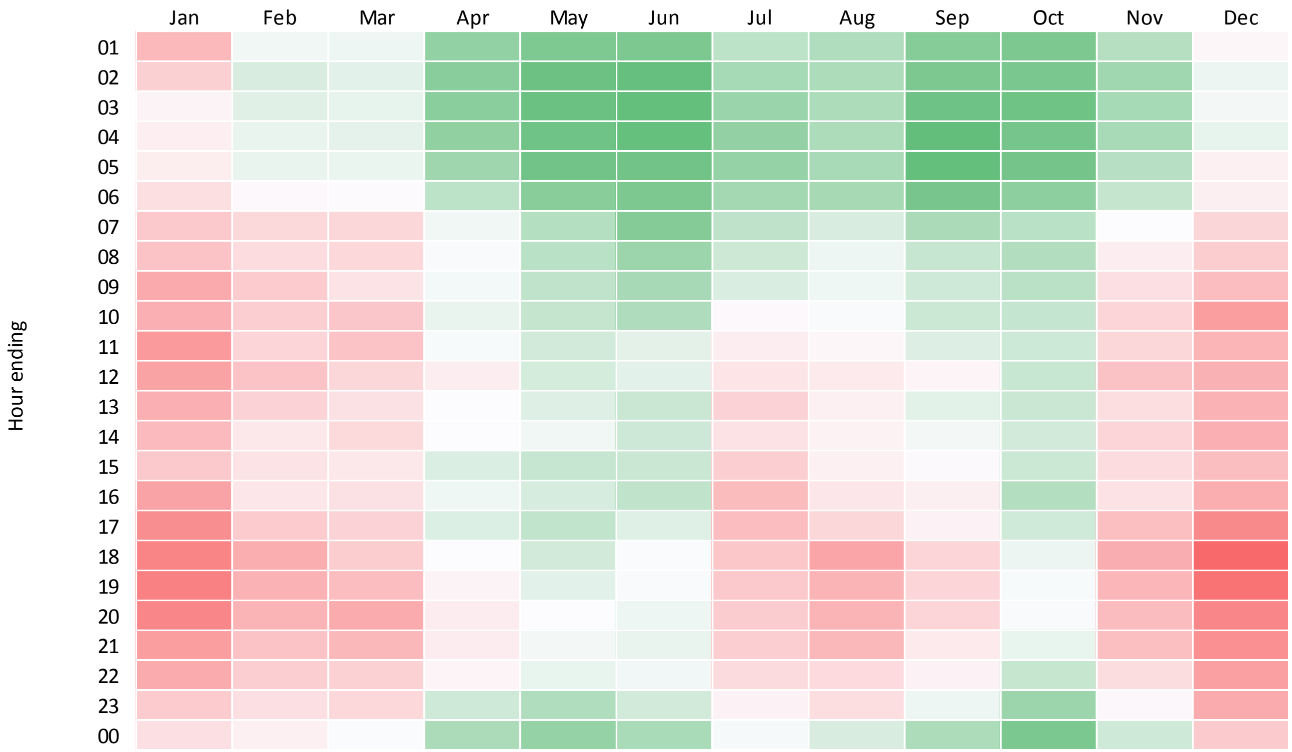
RESIDENTIAL LOAD HEAT MAP - 2020



- Seasonal and day/night patterns
- Load highest on winter evenings and mornings
- Low load overnight
- Generally low load in shoulder seasons (spring, fall)
- Range 50 MW – 275 MW

Red – high load, green – low load

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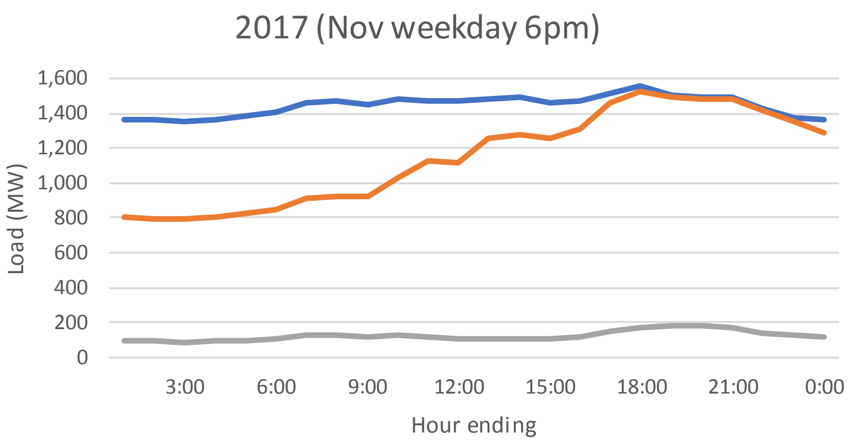
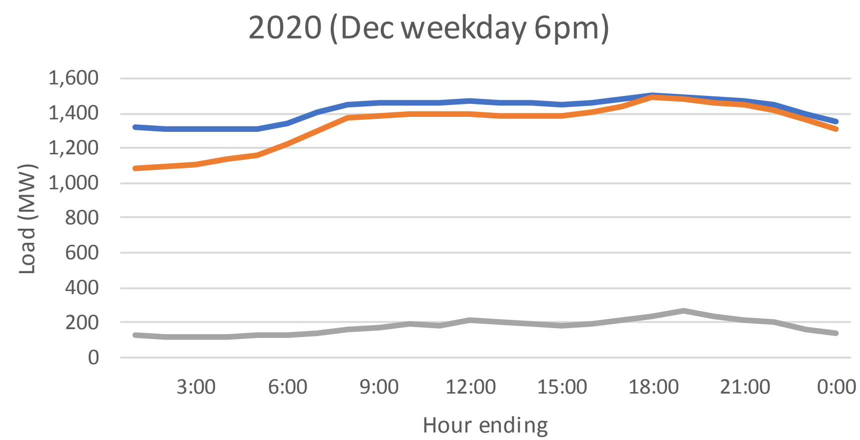
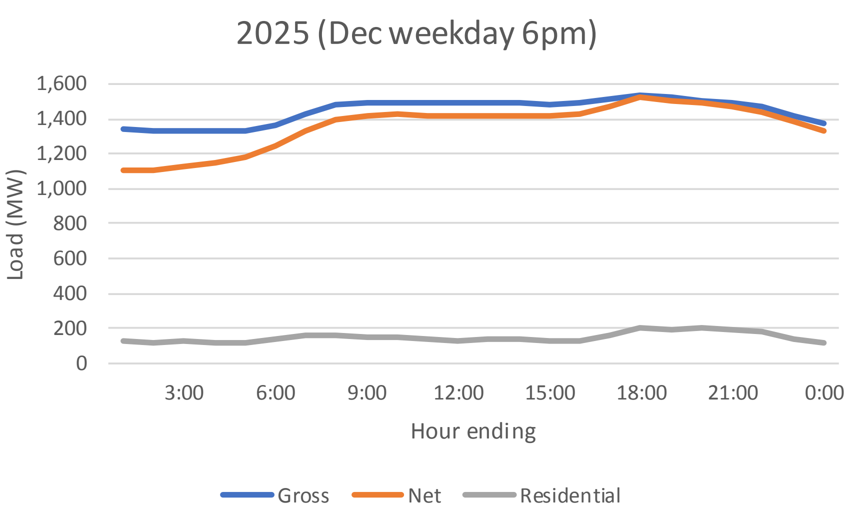
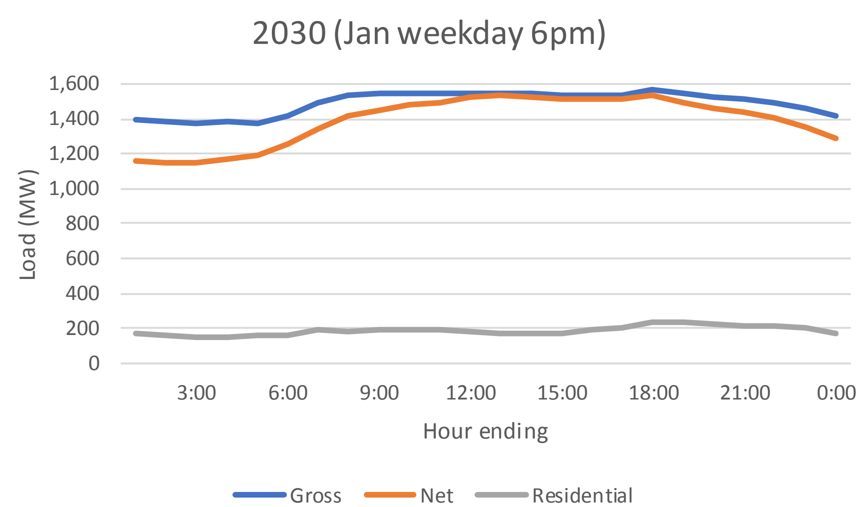
PEAK DAYS – BASED ON NET SYSTEM LOAD









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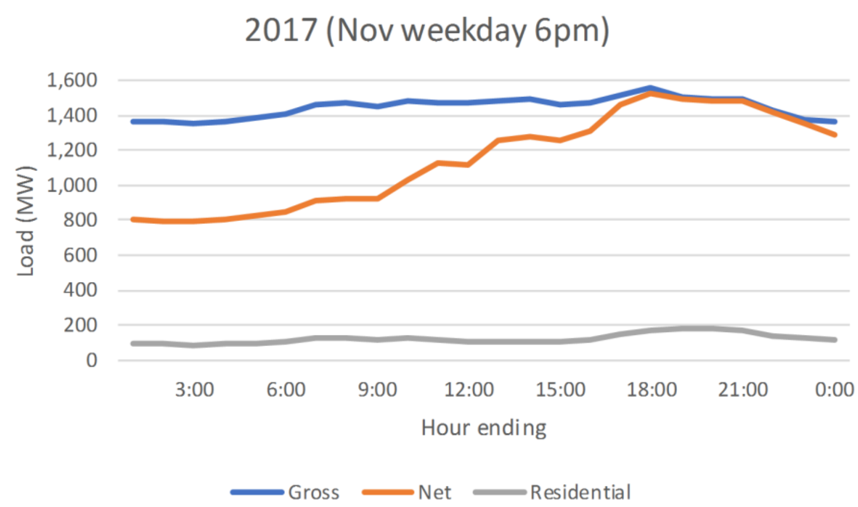
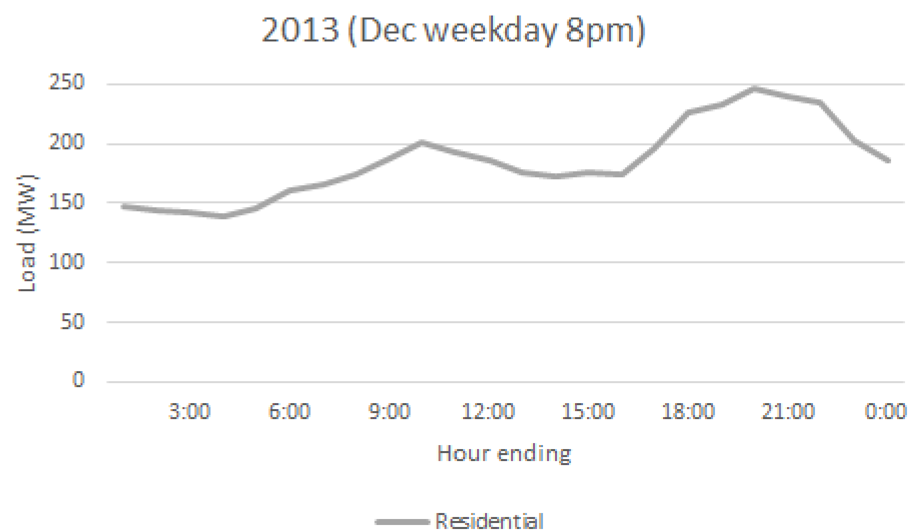
ZOOM: 2017 NET PEAK DAY - TUE 21 NOV

	Net load	Percentage of peak load	Residential load	Residential share of net load
1:00	803	53%	90	11%
2:00	797	52%	91	11%
3:00	794	52%	88	11%
4:00	805	53%	91	11%
5:00	827	54%	93	11%
6:00	851	56%	104	12%
7:00	908	60%	127	14%
8:00	926	61%	129	14%
9:00	925	61%	116	13%
10:00	1,030	68%	126	12%
11:00	1,125	74%	112	10%
12:00	1,115	73%	106	10%
13:00	1,252	82%	106	8%
14:00	1,278	84%	103	8%
15:00	1,258	82%	102	8%
16:00	1,307	86%	115	9%
17:00	1,464	96%	146	10%
18:00	1,525	100%	170	11%
19:00	1,495	98%	179	12%
20:00	1,484	97%	176	12%
21:00	1,476	97%	172	12%
22:00	1,416	93%	143	10%
23:00	1,356	89%	127	9%
0:00	1,284	84%	113	9%



ZOOM: 2013 RESIDENTIAL PEAK DAY – MON 23 DEC

	Residential load	Percentage of peak load
1:00	148	60%
2:00	143	58%
3:00	142	58%
4:00	140	57%
5:00	146	59%
6:00	162	66%
7:00	167	68%
8:00	174	71%
9:00	187	76%
10:00	202	82%
11:00	193	79%
12:00	186	75%
13:00	176	72%
14:00	173	70%
15:00	175	71%
16:00	175	71%
17:00	195	79%
18:00	226	92%
19:00	232	94%
20:00	246	100%
21:00	239	97%
22:00	235	95%
23:00	203	82%
0:00	187	76%



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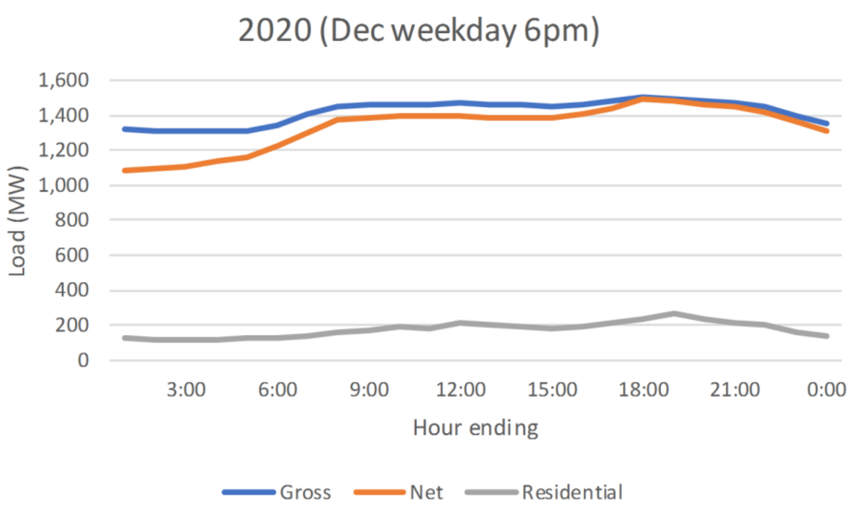
ZOOM: 2020 NET PEAK DAY – DEC WEEKDAY

	Net load	Percentage of peak load	Residential load	Residential share of net load
1:00	1,086	73%	122	11%
2:00	1,089	73%	117	11%
3:00	1,103	74%	119	11%
4:00	1,132	76%	120	11%
5:00	1,164	78%	123	11%
6:00	1,222	82%	128	10%
7:00	1,304	87%	142	11%
8:00	1,369	92%	163	12%
9:00	1,389	93%	171	12%
10:00	1,398	94%	193	14%
11:00	1,390	93%	184	13%
12:00	1,393	93%	208	15%
13:00	1,385	93%	199	14%
14:00	1,386	93%	197	14%
15:00	1,387	93%	177	13%
16:00	1,403	94%	188	13%
17:00	1,442	97%	207	14%
18:00	1,491	100%	234	16%
19:00	1,479	99%	266	18%
20:00	1,462	98%	236	16%
21:00	1,444	97%	215	15%
22:00	1,414	95%	207	15%
23:00	1,361	91%	154	11%
0:00	1,306	88%	138	11%



MISO LMP HEAT MAP

Hour ending	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
01	28	29	25	21	22	21	21	25	14	16	25	26
02	27	28	25	21	21	20	19	23	12	16	24	25
03	26	28	25	21	20	19	18	23	12	16	24	25
04	26	28	25	22	22	20	18	23	14	17	24	25
05	27	29	29	28	26	22	20	25	19	24	28	27
06	33	36	37	36	32	28	23	28	24	34	34	31
07	46	44	45	42	37	33	28	33	32	37	40	40
08	48	45	46	44	40	35	32	36	35	38	41	43
09	48	46	47	44	41	37	38	39	37	39	42	42
10	48	47	47	42	42	40	42	42	39	40	42	42
11	46	45	45	40	42	42	47	45	39	39	41	41
12	43	42	42	37	41	43	51	48	40	37	38	39
13	41	40	40	36	40	45	57	52	40	36	37	37
14	38	38	37	34	38	47	62	57	41	35	36	36
15	37	37	36	33	37	47	68	59	40	34	35	35
16	37	37	35	32	37	46	67	57	40	34	35	37
17	47	40	36	31	36	44	60	53	39	36	45	52
18	61	52	42	32	35	41	53	48	39	48	53	56
19	53	52	50	42	38	39	47	47	42	45	46	49
20	49	47	47	43	41	40	47	46	39	37	42	45
21	44	42	39	33	35	39	42	39	34	31	37	41
22	38	36	34	27	30	33	30	33	28	26	33	37
23	32	34	28	24	26	29	27	29	20	21	31	32
00	29	30	26	22	24	23	23	27	16	18	27	27

- Highest prices on summer afternoons and winter evenings
- Low prices overnight
- Seasonal variation less pronounced than for load
- Prices more aligned to MISO-wide load conditions than Minnesota Power load

Red – high price, green – low price

Data: MP-projected average LMP by hour by month at MP.MP_BOS4 node, 2020

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INDICATIVE MARGINAL COSTS

Function	Source	Cost (2020$/kW-year)	Cost (2020 Cents/kWh)*
Transmission	Mendota Group analysis of 30 US utilities (2014)	$25	1.7
Distribution	Mendota Group analysis of 30 US utilities (2014)	$52	3.5
Generation Capacity	Gross CT Cost of New Entry (LRZ 1)	$95	6.5
Energy	Residential load weighted LMP from 6 – 10 PM (2020)	N/A	4.3
Total Rate During Peak Hours		**N/A**	**16.0**

**Fixed costs are spread across the hours from 6-10PM, corresponding to Minnesota Power residential peak loads. Includes losses.*

Sample T&D Marginal Costs ($/kW-year)	Tx	Dx
Otter Tail Power (2016)	$72	$31
Xcel Energy (2014)	$14	$39
Mendota Group analysis average value (2014)	$22	$46

IMPLICATIONS FOR DESIGNING AN EFFECTIVE TOU RATE

Capacity type	Required based on	Load characteristics	Implication
Generation	Peak net system load	• Relatively constant • Day / night variability • Limited seasonal variability	TBD
Transmission	Peak gross system load		
Distribution	Peak residential load	• Significant intra-day and seasonal variability • Winter evening highest load period	More targeted peak period definition, e.g. winter evenings only

Rate design will need to take account of peak periods for different types of capacity, and balance these with other factors such as consistency, predictability and simplicity.

CONTACTS

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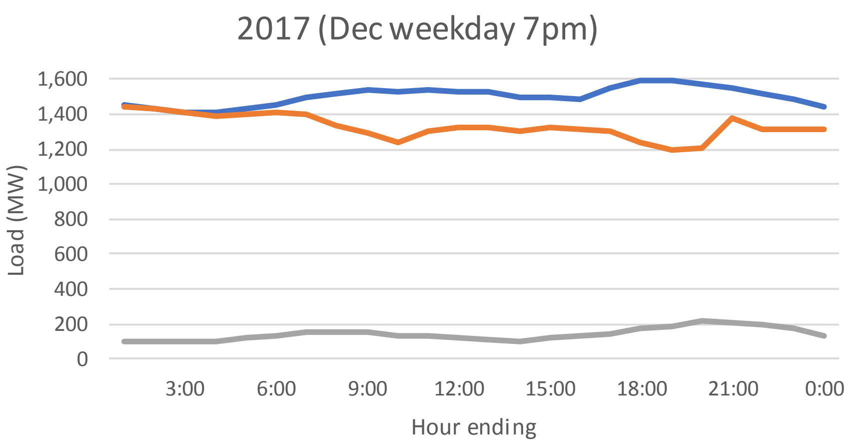
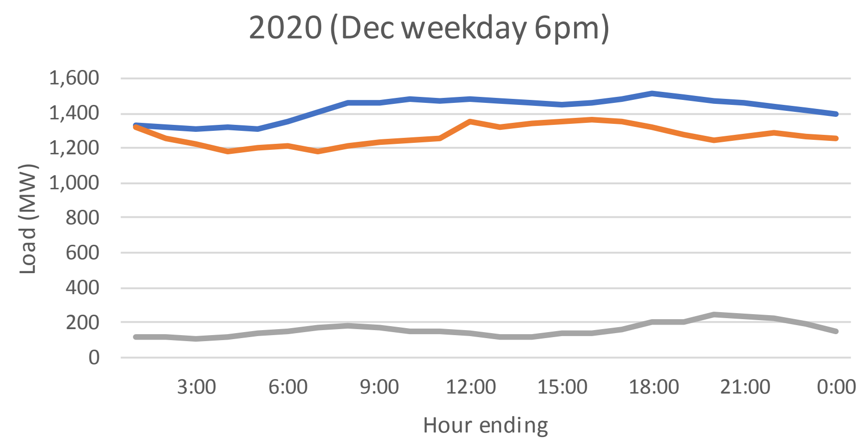
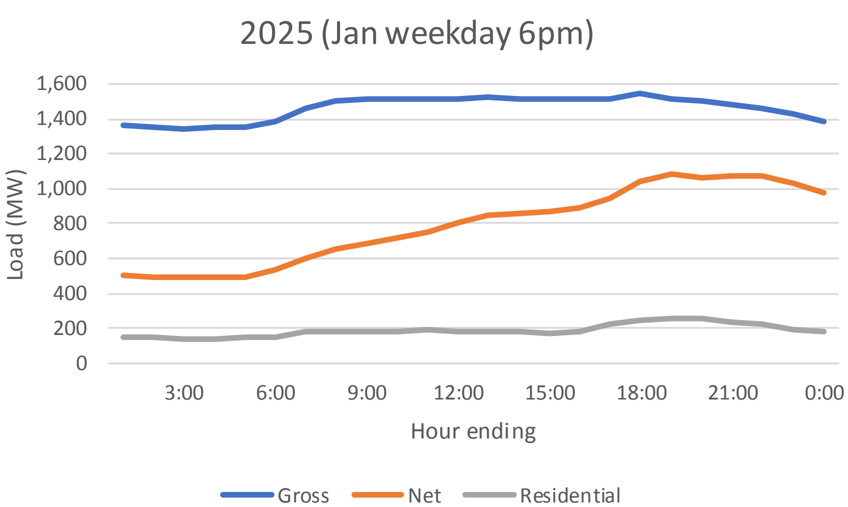
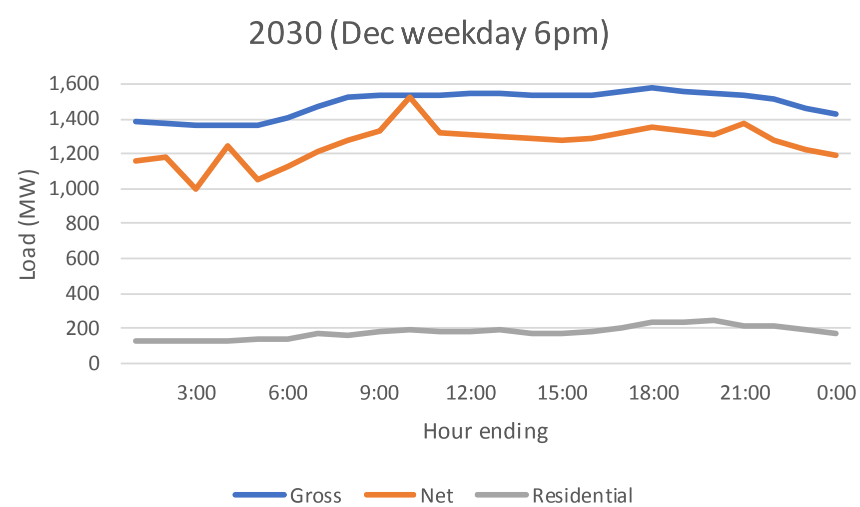
SUPPLEMENTARY MATERIAL

PEAK DAYS – BASED ON GROSS SYSTEM LOAD









MP TOD RATE PILOT – CURRENT RATES

	Standard Rate	Off-peak Discount of $0.0299 calculated rate in this column	On-peak Increase of $0.04870 calculated rate in this column	Critical Peak Increase of $0.77 calculated rate in this column
0-300kWh ($/kWh)	$0.05098	$0.02108	$0.09968	$0.82098
301-500kWh ($/kWh)	$0.06735	$0.03745	$0.11605	$0.83735
501-750kWh ($/kWh)	$0.08168	$0.05178	$0.13038	$0.85168
751-1,000kWh ($/kWh)	$0.08445	$0.05455	$0.13315	$0.85445
> 1,000kWh ($/kWh)	$0.08937	$0.05947	$0.13807	$0.85937

Source: Minnesota Power Time-of-Day Rate Pilot

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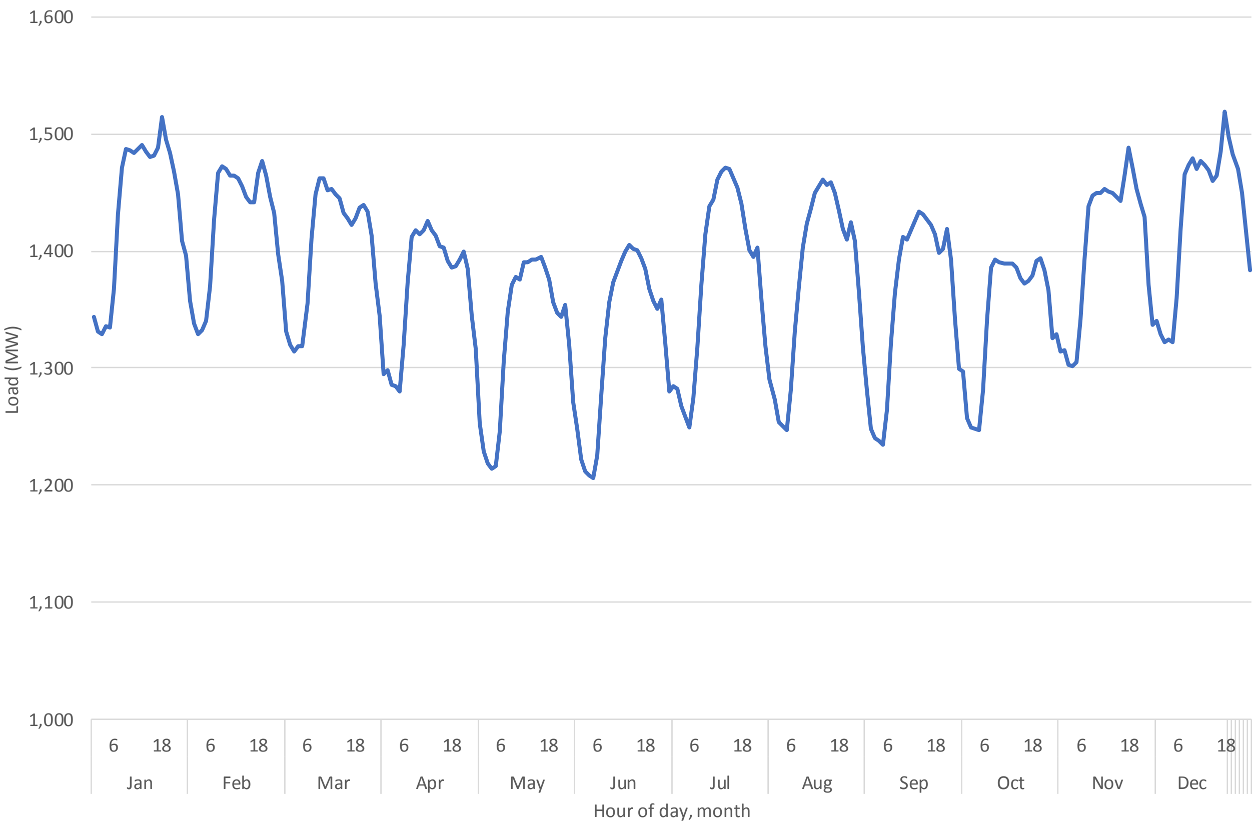
GROSS SYSTEM PEAK LOAD
BY TIME OF DAY AND MONTH - 2020



- Load is relatively flat across the year and across the day when compared with other utilities, driven by high share of large industrial load
- Peak in winter, with summer higher than shoulder seasons

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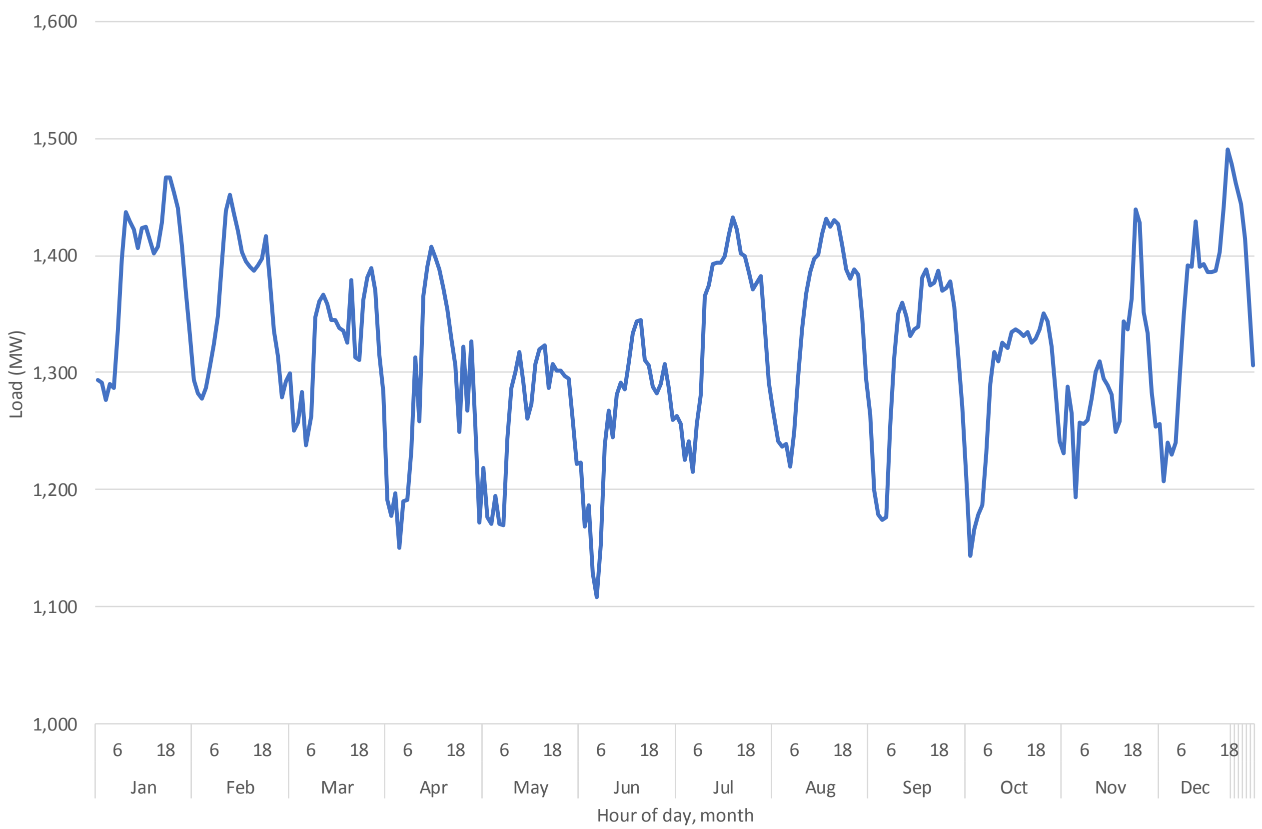
NET SYSTEM PEAK LOAD*
BY TIME OF DAY AND MONTH - 2020



- More variability than gross load, but still relatively flat
- Includes planned additions of renewable generation

- *Net load is gross load less wind and solar generation*
- *The Minnesota Renewable Energy Standard requires public utilities (other than Xcel) to obtain 21.5% of their energy from renewable energy sources by 2020 rising to 26.5% in 2025 (including a 1.5% solar carve out in all years)*

NAVIGANT

seventhwave

CPP impacts for Minnesota Power's Time-of-Date Pilot

Scott Pigg

September 2018

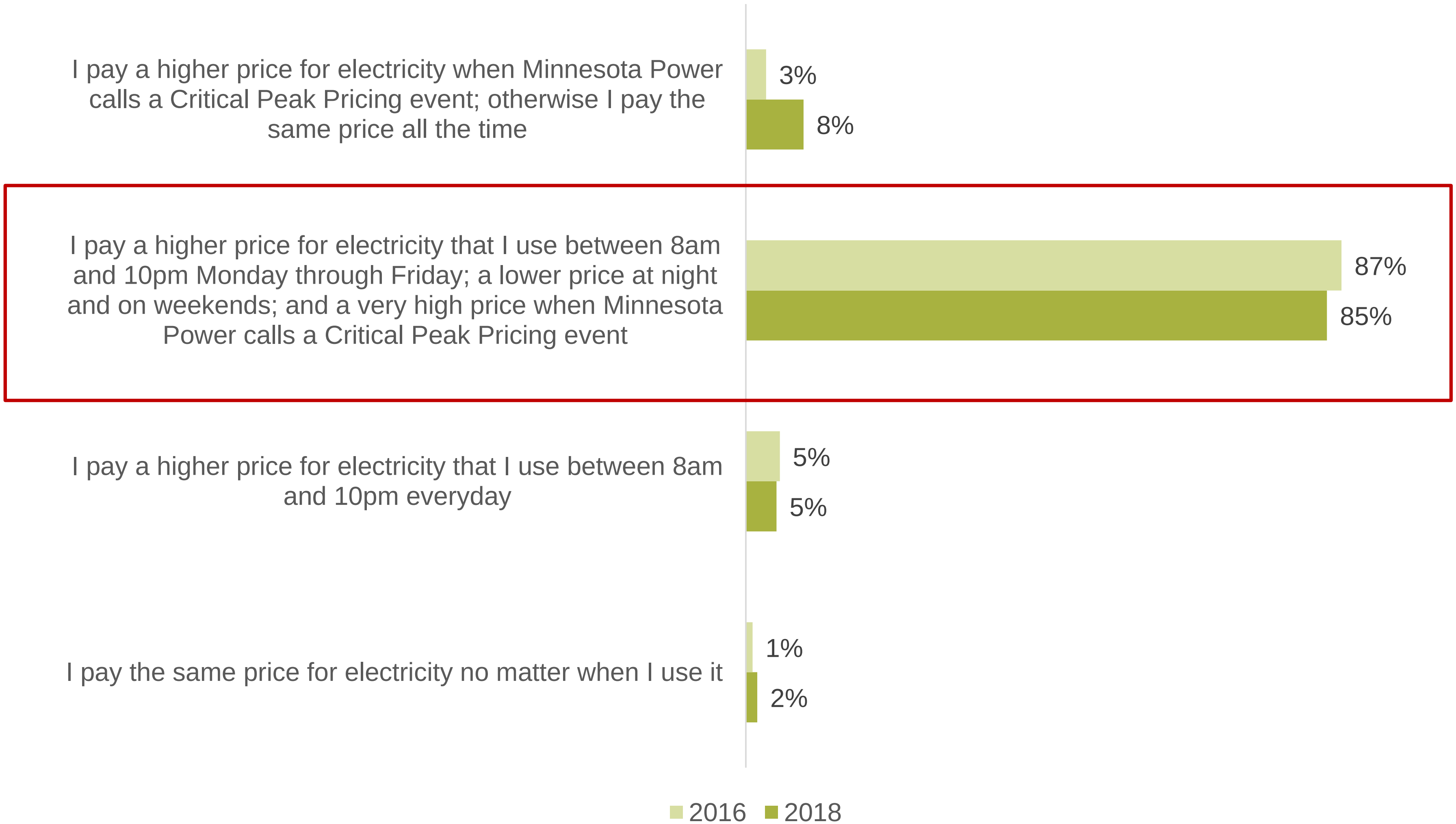
Scope

- Analyzed Critical Peak Pricing component of pilot rate
- Two analysis rounds
  - 6 events in 2015
  - 16 events in 2017/2018
- Conducted participant surveys
- Analyzed load impacts from metering data

Key Participant Characteristics

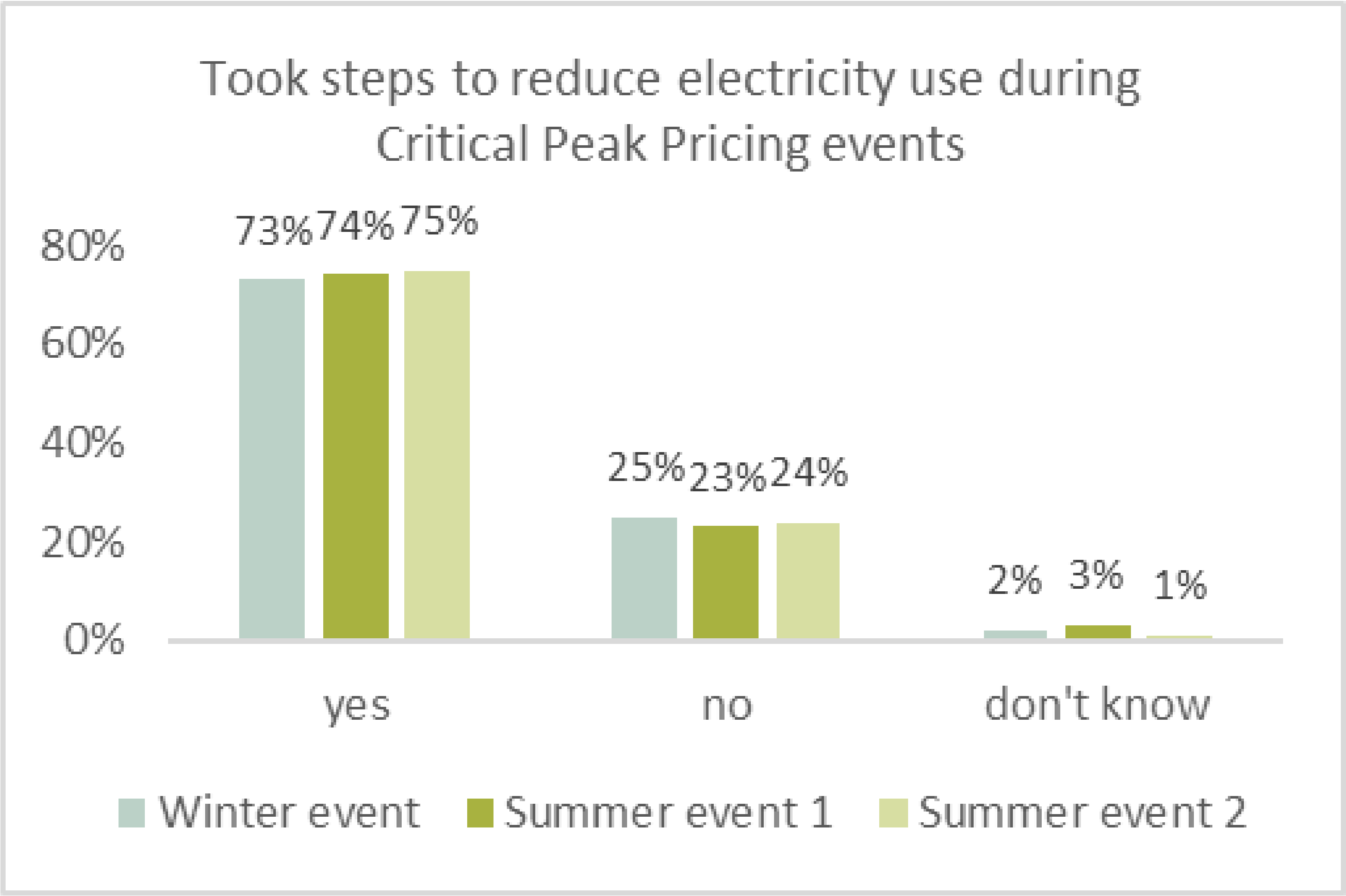
- Overwhelmingly single-family homeowners
  - 23% family w/ children
  - 27% family member age 65+
- 8% electric heat
- 36% central A/C; 48% room A/C
- 51% electric water heater
- 85% electric dryer
- 82% electric range
- 83% use a dehumidifier

Participants have a good understanding of the plan



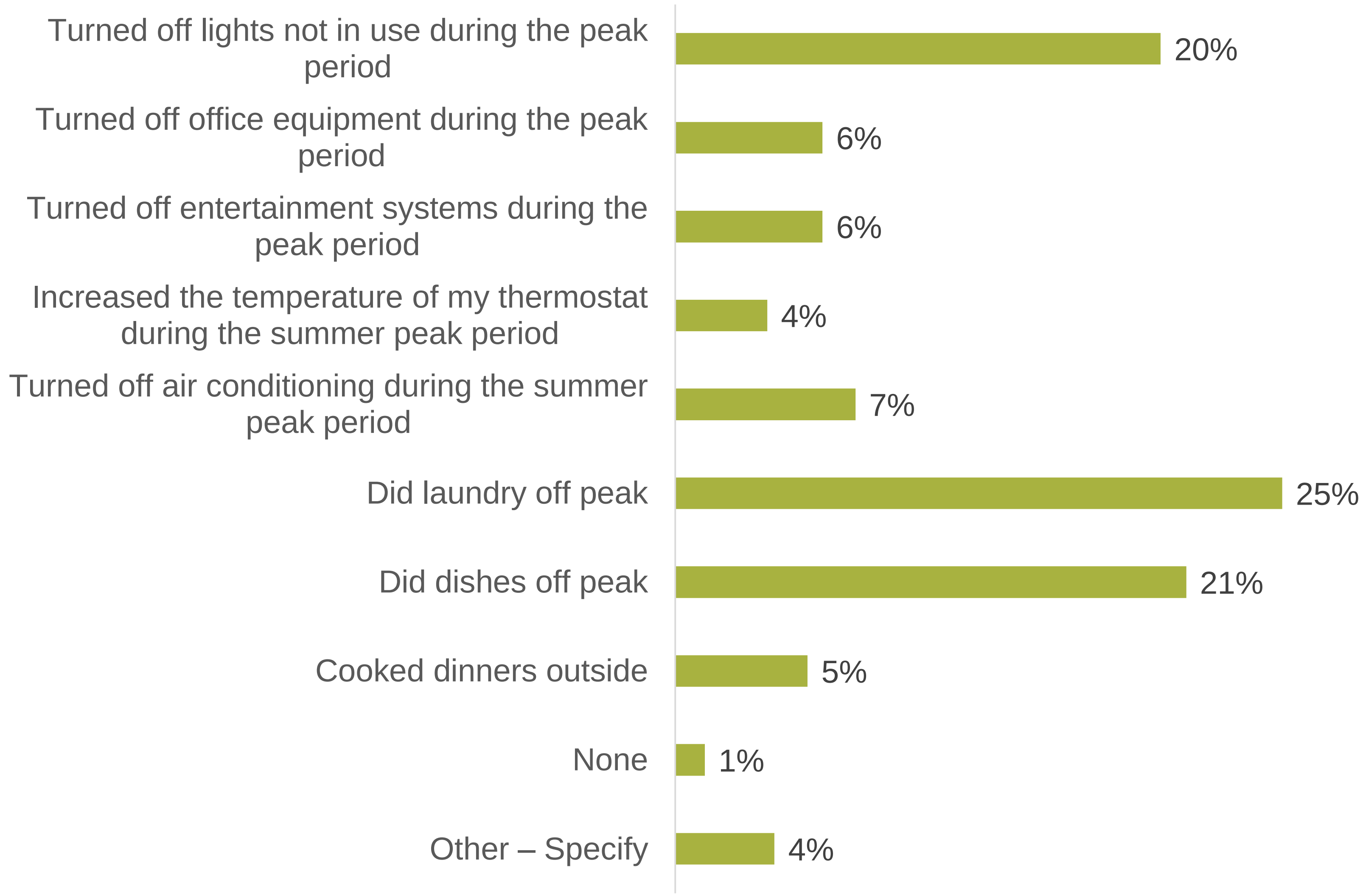
(2016 and 2018 surveys)

Most take steps to reduce consumption



(2015 post-event surveys)

Reported actions taken during CPP events



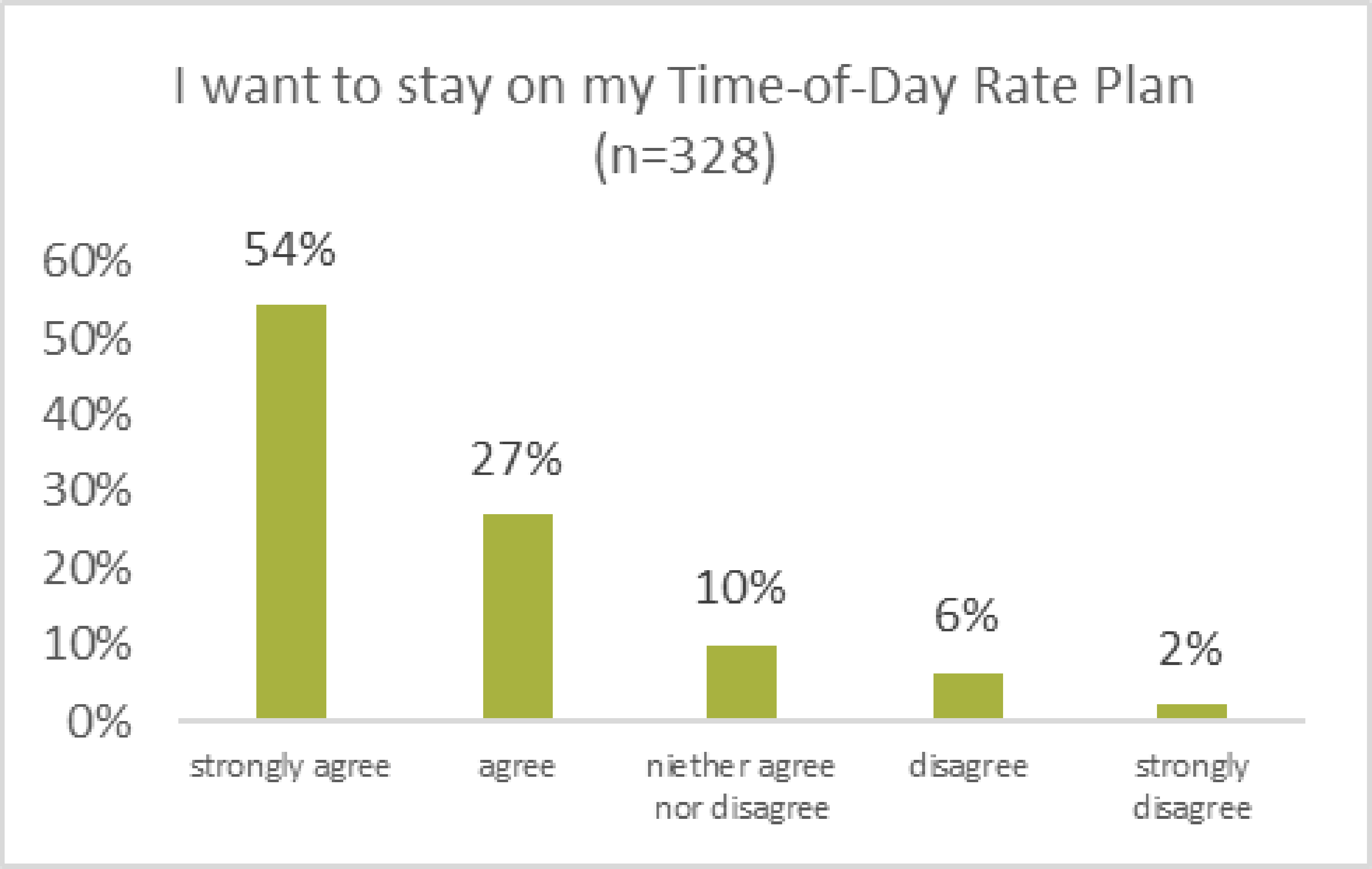
(2018 survey)

Some people took significant steps…

- Summer
  - “Hid in the dark. It was hot.”
  - “It was hot so I napped on the front porch for the entire period. No phone, no lights, no electrical devices, not a single luxury.”
  - “Shut off everything but refrigeration.”
- Winter
  - “No electricity for making dinner.”
  - “Did not cook, including stove, oven, microwave, etc.”

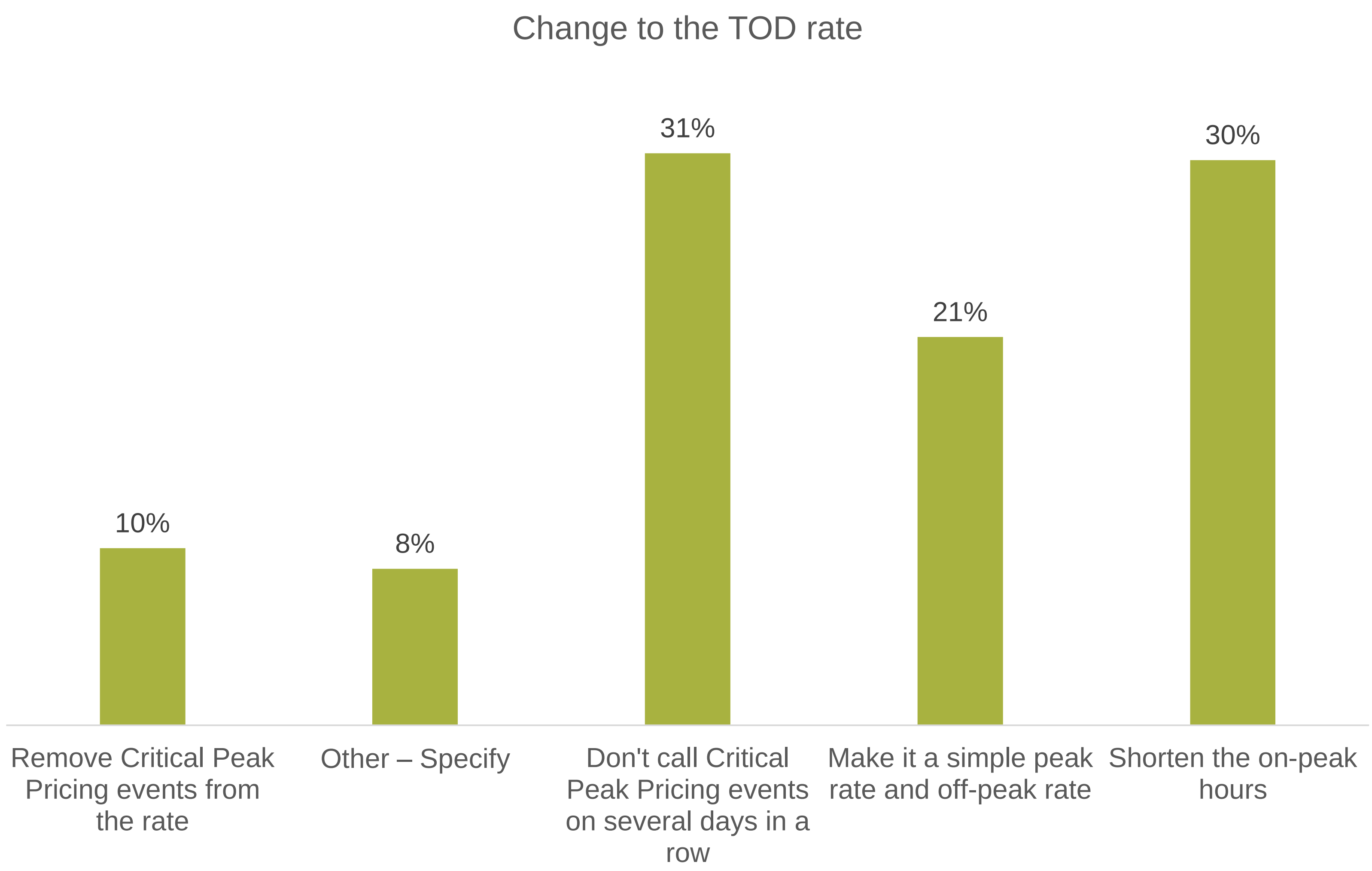
(2015 post-event surveys)

Most are happy with the rate



2016 survey

Suggested changes to the TOD rate



(2018 survey)

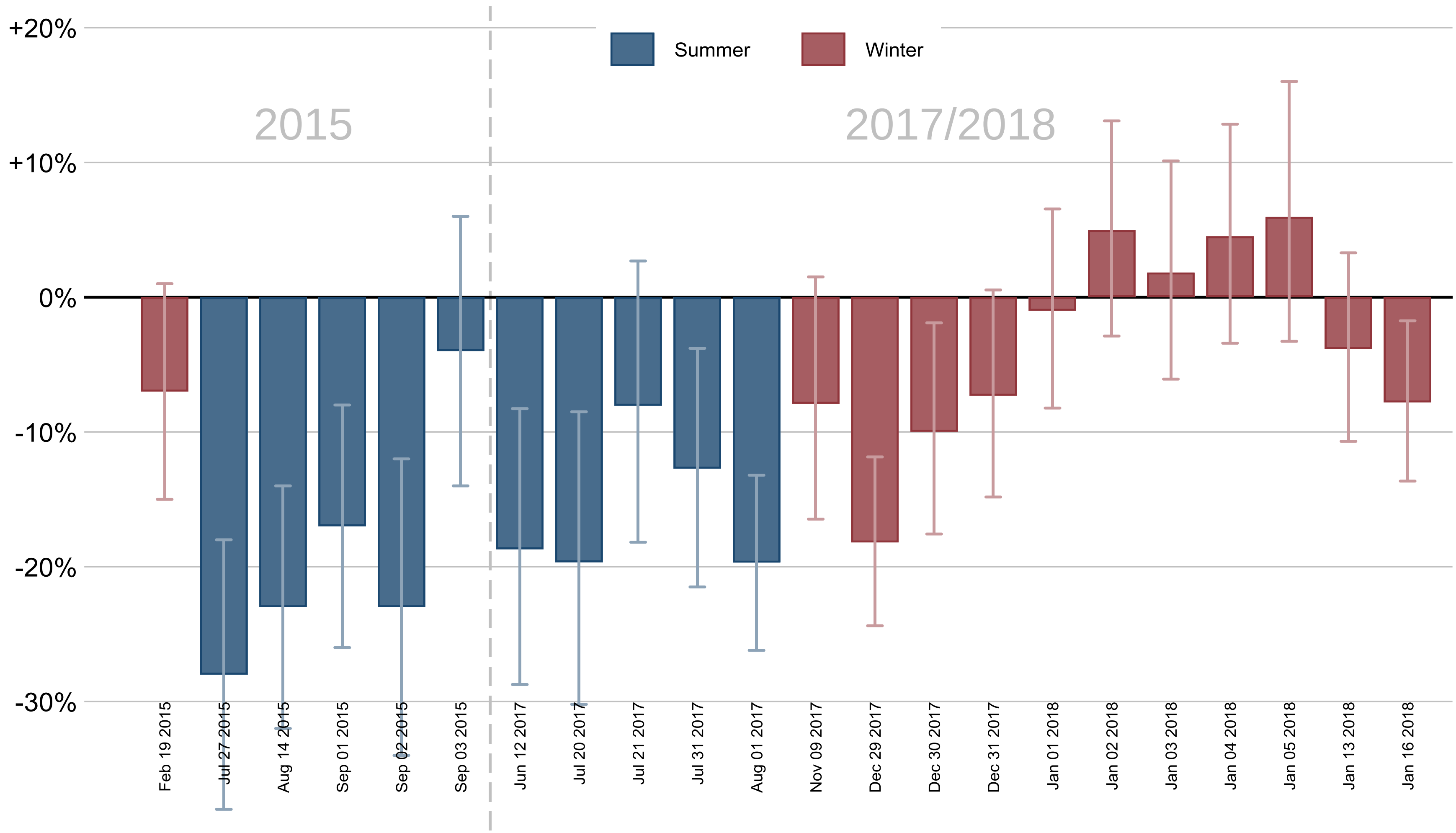
Method for Estimating Load Impacts

1. Match each event day with a “proxy” day with similar weather
2. For each hour of the day, calculate difference in mean load between event day and proxy day
3. Do the same for a group of non-participants, weighted to match participant usage profile
4. Calculate net hourly impact as mean Participant Δ minus Non-participant Δ

Load impact results

Season	Events	Mean change in load during event	
		watts per customer	Percent
Summer	10	-153	-17%
Winter	12	-67	-4%

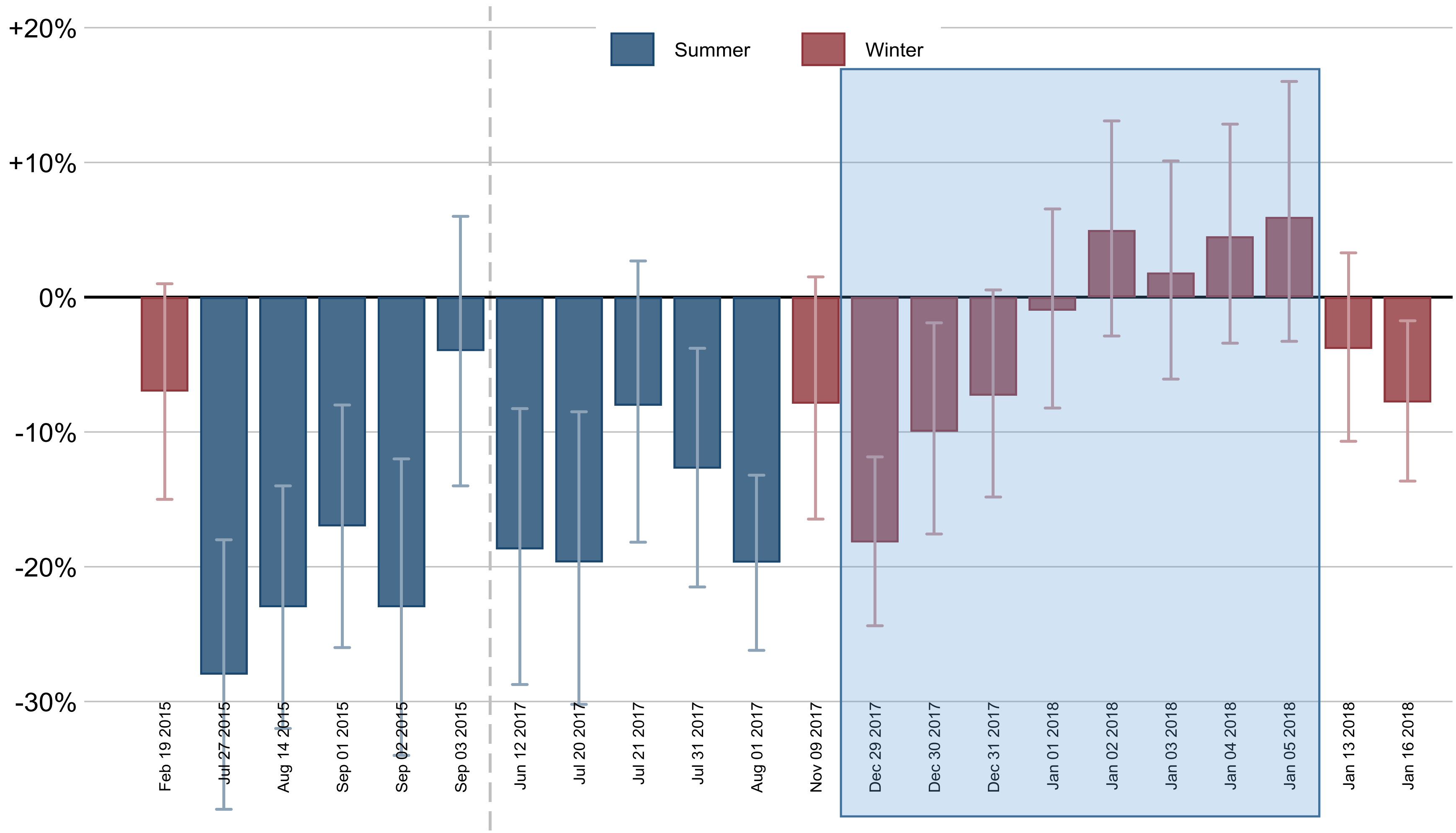
Load Impact by Event



(Vertical lines are 95% confidence intervals)

Attachment A

8 Straight Days of Winter Events



(Vertical lines are 95% confidence intervals)

Summary

- Vast majority of participants understand the rate
- Most take action during CPP events
- Summer load impacts > winter impacts
- Evidence of customer fatigue from multiple events in a row

Minnesota Power Time-of-Day Stakeholder Engagement

Meeting 2: September 28th, 2018

Detailed Notes

Contents

I. Discussion of Objectives and Design Principles

1. **The goal is that we are driving towards a program, not a pilot.**
2. **The goal is for time-of-use rates to be available to as many customers as possible - so long as the numbers pencil out in terms of cost-effectiveness.**
    a. AMI has benefits outside of a time-of-use rate, so it would be important to include what the benefits are outside of the time-of-use rate, when analyzing cost-effectiveness. However, it is difficult to quantify some benefits (including customer satisfaction and some other benefits).
3. **MP is deploying AMI through its capital budget and not seeking special cost-recovery. It will be rolled into a rate case as a capital expense**.
    a. MP is putting in AMI as the old meters are replaced.
4. **MP is a winter peaking utility, but the summer peak cost is very close to the winter peak.**

a. MP has a significant number of customers who use electric heating infrastructure and it will be important to consider that in determining whether those customers should be eligible for the TOD rate.
    i. Dual fuel customers have a special rate and are interruptible in the case of a peak event. It is an open question whether those customers could be or should be included in the TOD rate. 13-14% of customers are on the dual fuel rate.
b. Typically, TOD rates have exclusions for certain customers – it depends on the billing system and other rate structures that exist.
c. Exemptions can be limited to certain phases of the program.

II. Presentation: System Load Characteristics (Lon Huber)

1. **Minnesota Power has a very unique electric system.**
    a. Includes 74% industrial load
    b. The load is relatively flat over the year – average gross load is 89% of peak gross load. A typical ratio would be closer to 50%
    c. Net load (gross load minus wind and solar) is also relatively flat
    d. Average residential load is 51% of peak residential load
    e. Winter peaking is caused by electric heating and electric supplemental heating as well as a low penetration of AC (which keeps summer peak relatively low)
    f. 40% of MP's residential customers are in the city of Duluth
    g. Residential load makes up less than 10% of gross load
    h. 2017 MP System Peak is at hour 18 (6pm), while 2013 residential peak was at hour 20 (8pm). 2013 is the most recent year with vetted data.
    i. MP has a fairly stable load over the peak day (net load)
2. **Wind can make it difficult to forecast net peak load timing**
3. **MP's latest IRP determines the underlying assumption of the resource mix for Navigant's analysis**
    a. Assumed 4% peak growth from 2020 to 2030 overall
    b. Assumed 7% peak growth from 2020 to 2030 for residential
4. **MP has no peaking resource – what comes online at peak? What's driving peak costs?**
    a. MISO prices are highest on summer afternoons and winter evenings
    b. Navigant provided indicative marginal costs: a check on the marginal cost during peak (Based on average marginal cost data)
        i. $ 0.16/kWh
        ii. MP residential block rates range from $0.5-0.8/kWh
    c. Heating is particularly tricky for time-of-use rates

d. There may be less of a cost benefit through an MP TOD than typical utilities.
    i. But MISO market dictates prices and capacity requirements.
e. If MP is building to cover peak vs. If MP is building as a hedge for wind intermittency will determine value.

5. **How do we want to look at peak hours for a system with an incredible load profile?**
    a. Could do 12 hours of peak based on the profile.
    b. How to design a capacity focused TOU in this unique system?
    c. Generation fleet is unique too. MP is moderating base plants, not peakers or CTs.
6. **Could CPP help MP address wind intermittency?**
    a. Depends on the accuracy of the forecast. MP provides day-ahead notice for CPP.
    b. Wouldn't be able to give day-ahead notice on a CPP to address wind intermittency.
    c. Does CPP create snap-back issues? Relatively flat load can exaggerate the issues of snap-back.

III. Presentation: CPP Findings from the Smart Grid Pilot (Scott Pigg)

1. **Analysis context:**
    a. MP's current CPP has a 3 hour window with day-ahead notice
    b. Looked at 6 events in 2015 and 16 events in 2017/2018
2. **Participant characteristics:**
    a. Mostly single-family home participants
    b. 8% electric heating
    c. 36% central A/C and 48% room A/C
    d. 51% electric water heater
    e. 83% electric dehumidifier
3. **Findings from participant surveys:**
    a. People mostly understood the rate
    b. Most people took action to reduce their electric usage during a CPP event.
        i. Most people reported turning things off that were not in use and doing laundry/dishes during off-peak
        ii. Some people took drastic steps
    c. People were generally happy with their TOD rate
4. **Load Impact Results:**
    a. Got more of a reduction in summer events (1-3pm) than winter (5-8pm)
        i. 17% reduction in summer (153 watts reduction)

ii. 4% reduction in winter (67 watts reduction)

b. In 2017/2018 the winter events at times went positive (usage might have increased), but 8 of those events were on consecutive days over the New Year holiday. The first day (1 of 8) of consecutive CPP events had about an 18% reduction, but that reduction waned and disappeared over the subsequent CPP days. Indicates CPP fatigue.

5. **How much did it cost people who didn't reduce usage during CPP events?**
   a. Rate goes up during those windows to $0.77/kWh, so the bill impact can be significant, especially for electric heating and supplemental electric heating
6. **What was the value to MP for the CPP events?**
   a. Very tiny impact to MP. Lost about $10 per customer in the first year of the program, then adjusted the on-peak adder from $0.14 to $0.49.
   b. MP hit cap on hours that they can call a CPP
   c. MP is not decoupled
   d. CPP could impact the amount of money that MP makes depending on how customers respond.
   e. 2016 had no events due to moderate pricing
   f. Determining a CPP is based on cost
      i. Market price related – day-ahead MISO pricing
      ii. MP has discretion on whether to call CPP or not – has internal guidelines for when to call CPP based on market price
7. **Could MP have separate groups of customers in order to avoid CPP fatigue when there are multiple CPP days in a row?**
   a. Hard for customers to know how much they are saving or spending with TOD vs. regular MP rates.

IV. Discussion: Objectives, Design Principles, Roll-out Plan

1. **How will the TOD interact with CARE and Budget Billing?**
   a. Need to follow up on this in subsequent meetings
2. **Designing a TOD Rate for this unique load profile**
   a. May make most sense for MP's TOD to track to MISO market rather than MP's own gen resources. – weighted average Locational Marginal Pricing (LMP)?
   b. Would be difficult to determine when renewables are on the margin for the MISO system -- makes it challenging to meet the objective to design a rate that helps integrate renewables.
3. **What is the best structure to reduce costs in this system?**
   a. Cost causation linkage will be less clear for MP than other utilities given MP's unique profile.

   b. Group is flexible to best way to structure a TOD for MP with full recognition that MP has a very unique system.

4. **Concerns:**
   a. Not all stakeholders can support Part 4 (Deployment Process) of that document
   b. Revenue neutrality is more challenging without a decoupled rate structure. If customers respond to price signals, as intended, the utility may not recover sufficient to stay revenue neutral.

V. Reflection, Wrap-up, and Next Steps

1. Next meetings will be to review the rate design options put together by MP and Navigant.

Minnesota Power Advanced Time of Day Rate
Meeting 3: December 10th, 2018

Mill City Museum – ADM Room
710 S 2nd Street, Minneapolis, MN 55401

10:00am – 2:00pm

For remote meeting access, please click this link at the meeting time:
https://betterenergy.zoom.us/j/275325095

Note: for optimal audio quality, we suggest using headphones or a headset

Draft Agenda

10:00-10:10am	Welcome, Intro's
10:10-10:30am	Review and Discuss Prioritized Design Principles
10:30-11:00am	Presentation on Feedback from MN Power Customer Workshops
11:00-12:00pm	Presentation on MN Power's Draft TOD Recommendations
12:00-12:30pm	BREAK- Grab Lunch
12:30-1:45pm	Discussion:

- What are the strengths of the recommendations?
- What improvements could be made to the recommendations?
- How well do the draft recommendations align to the design principles? (and/or are there suggested changes to the design principles?)
- What, if anything, would cause you to oppose the package of recommendations as a whole?
- What additional information would be necessary to evaluate the recommendations?

1:45-2:00pm	Reflection, Wrap-up, and Next Steps
2:00pm	ADJOURN

Customer Insights from Online Energy Survey

minnesota power

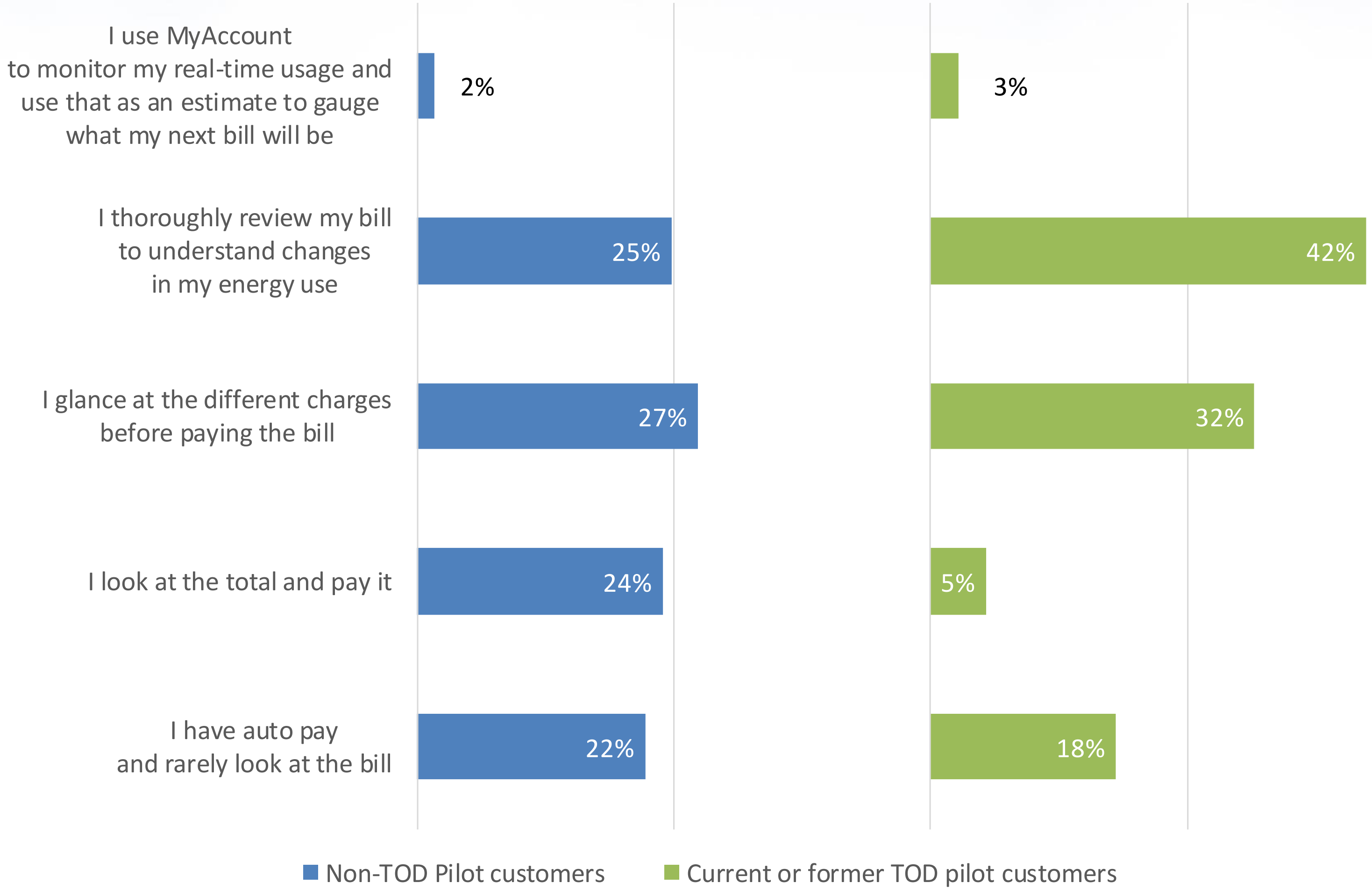
AN ALLETE COMPANY

EnergyForward

Overview

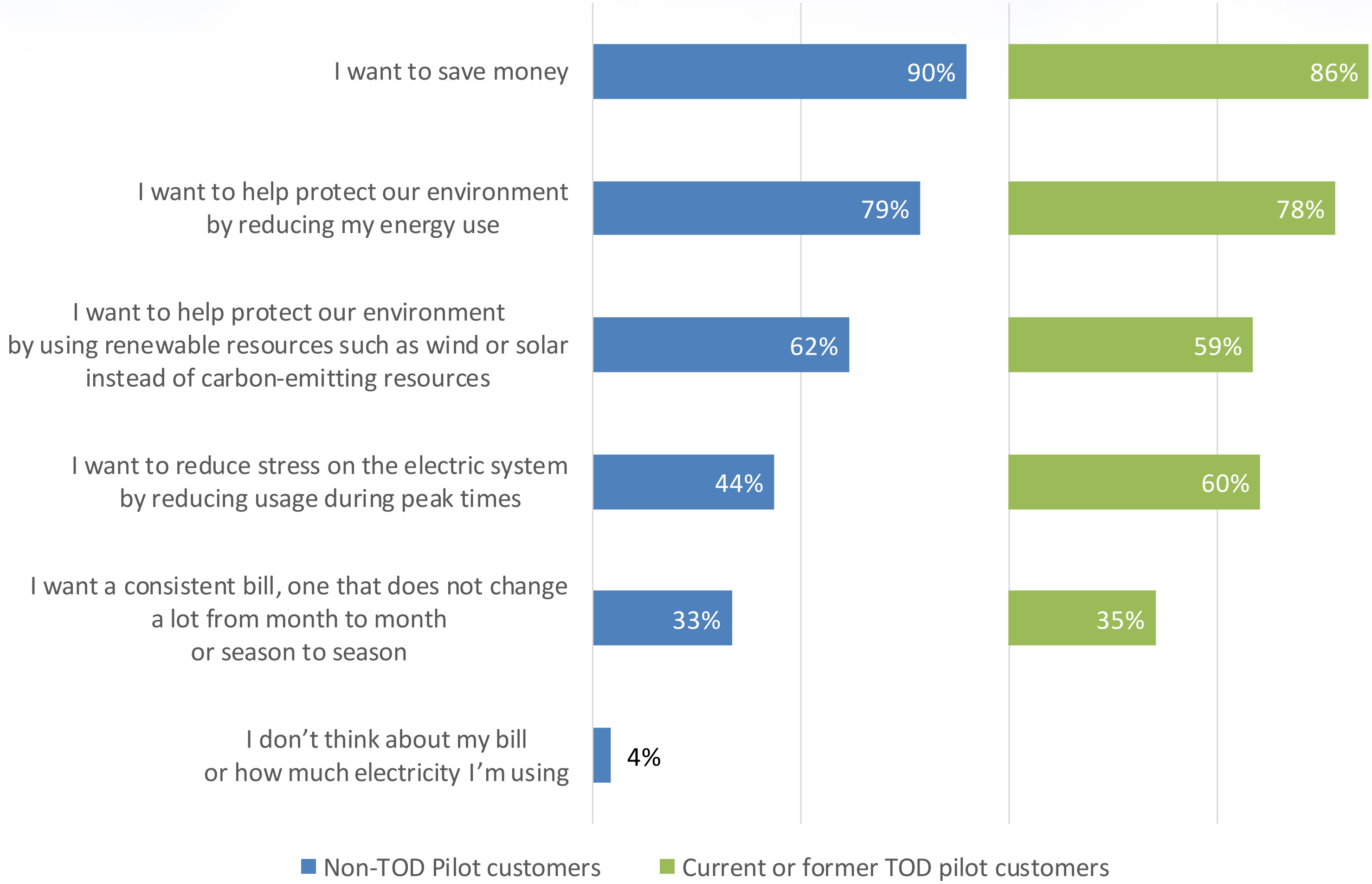
- In October of 2018 an online survey from Minnesota Power was promoted to customers through various digital channels (social media, Time-of-Day Rate Pilot past and present participants direct emails, known Electric Vehicle owner emails)
- Dates: 10/17/18 – 11/5/18
- Responses: 229 (1 Partial) – 111 with a connection to the TOD pilot
- Limitations: online only, potentially biased based on how it was conducted and who we were able to "direct market" it to

TOD customers are interested in the details of their bill



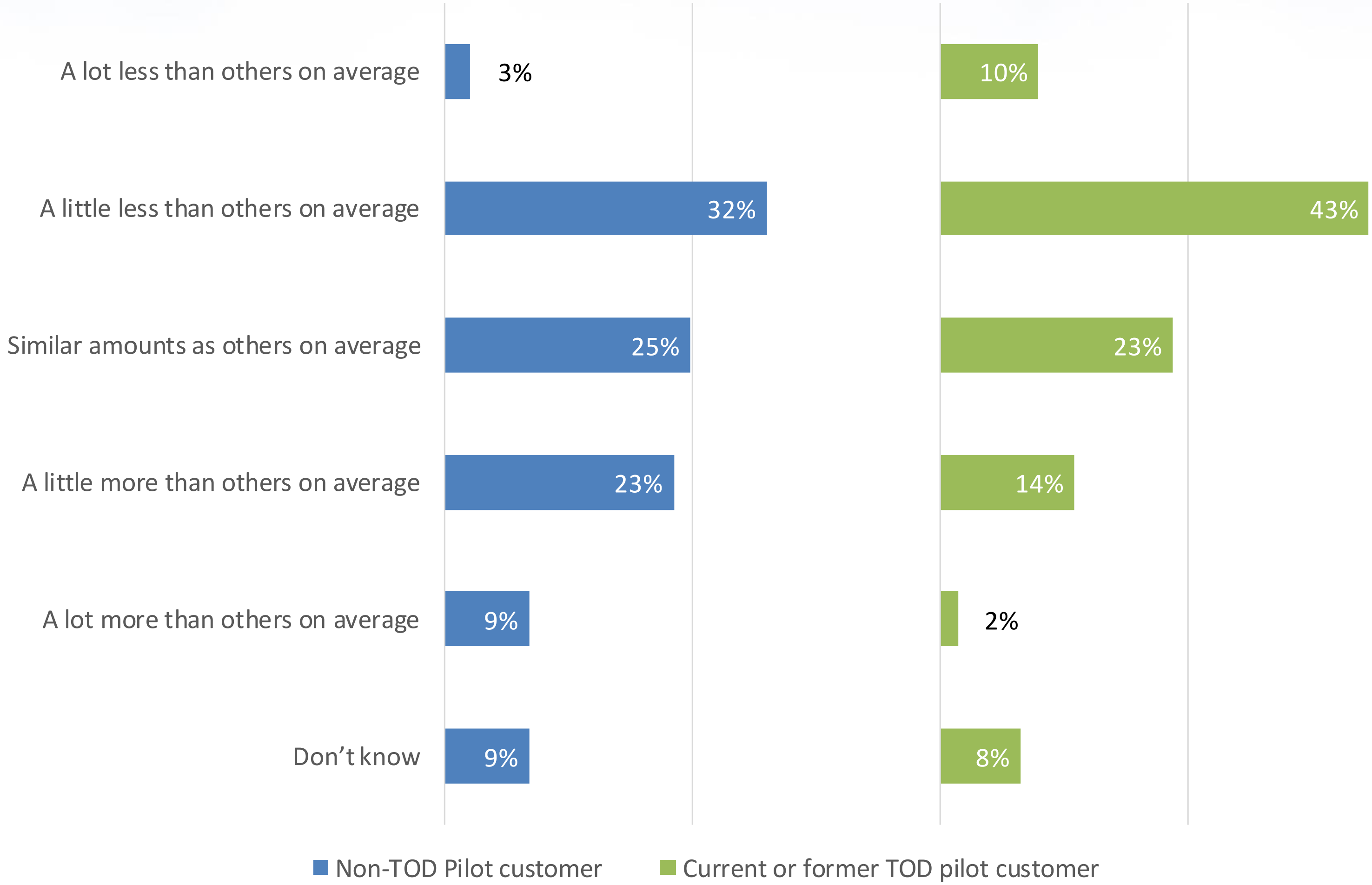
Q: Which of the following statements most closely describes how you handle your monthly electric bill?

The most important factor for customer participation in a TOU program is saving money



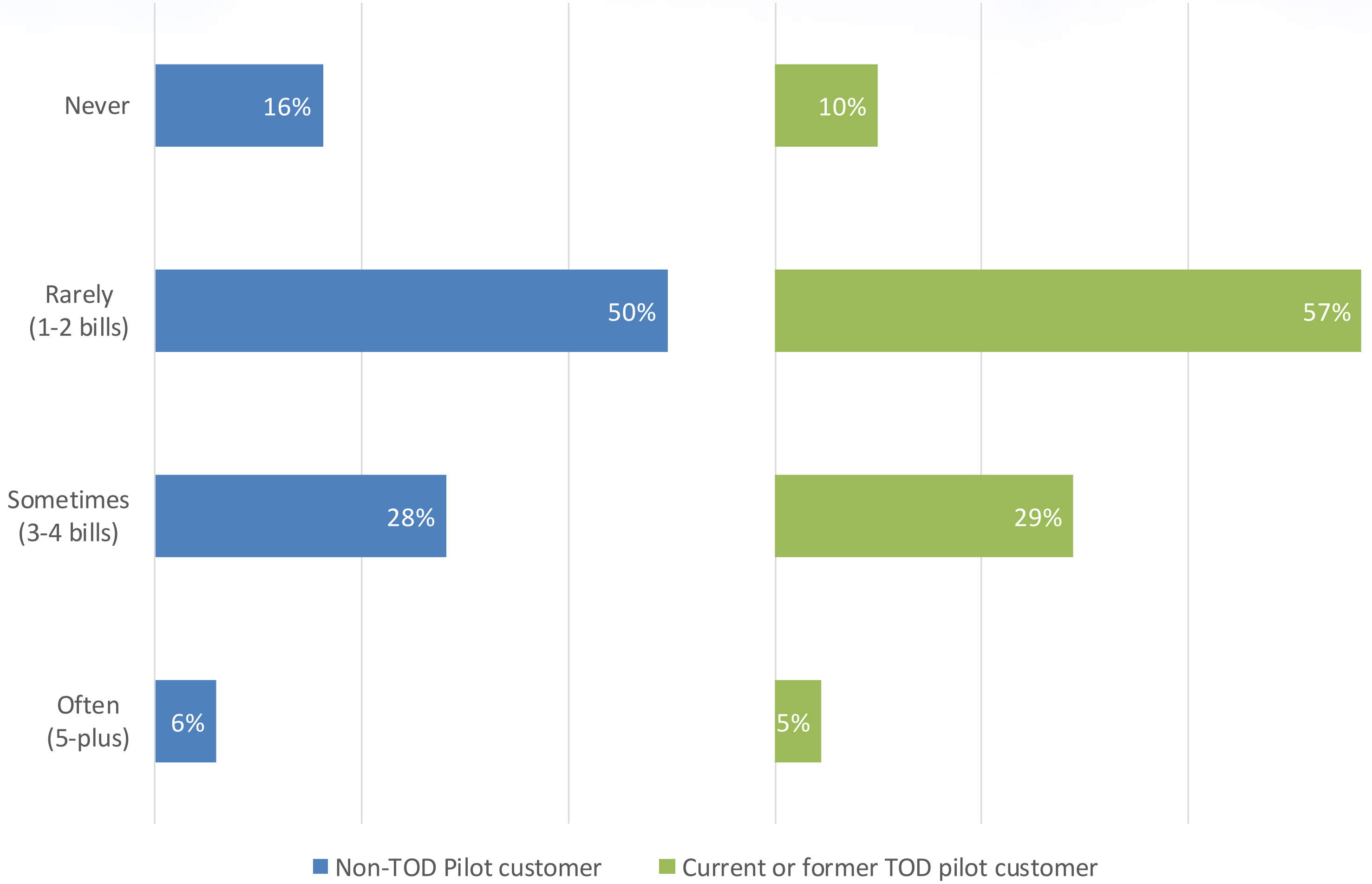
Q: Please select all statements that apply to you:

Approximately 60% of customers feel they use similar or less amounts of energy when compared to others



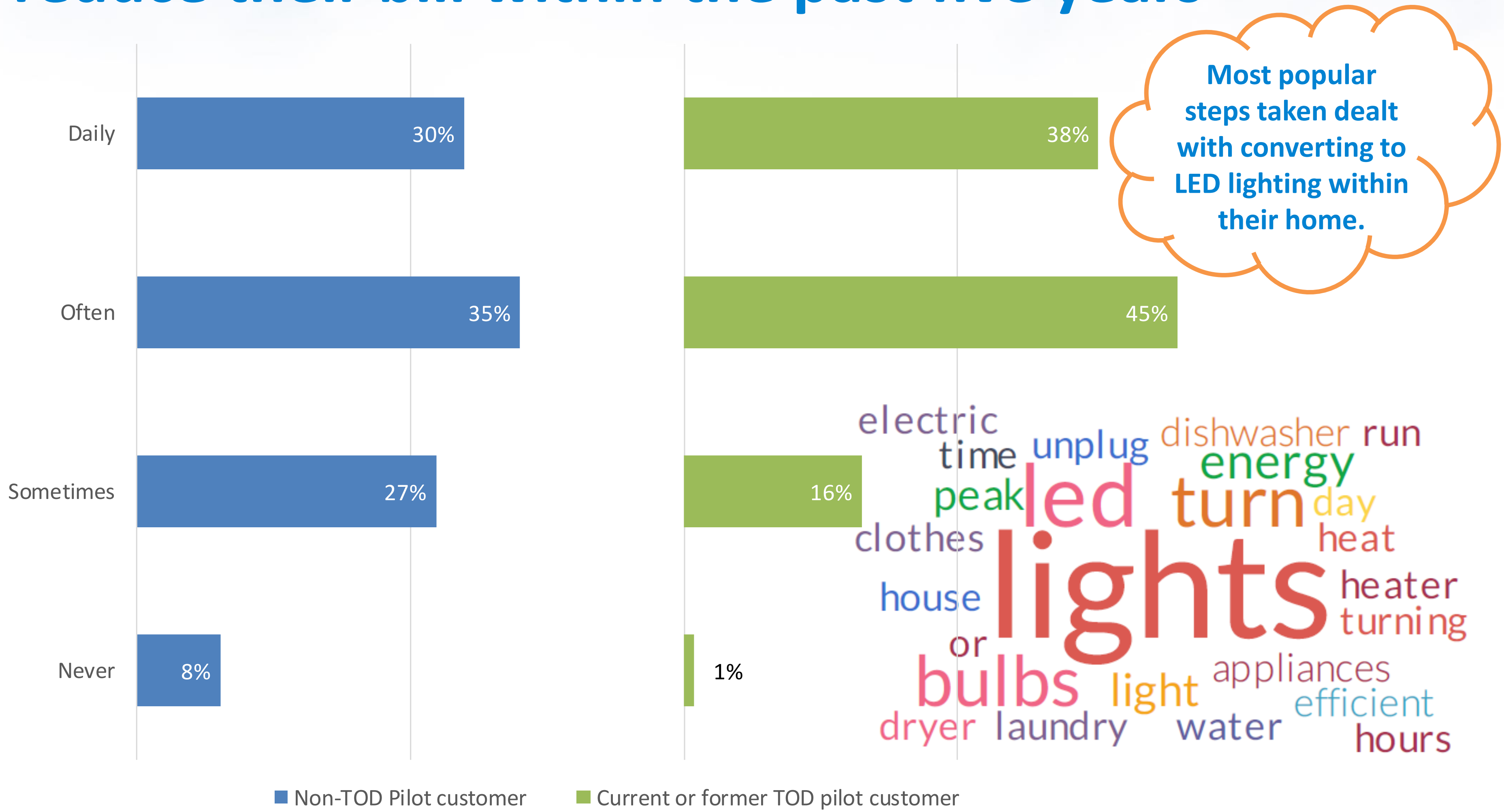
Q: When you think about the amount of electricity you use every month, do you think you are using:

Approximately 85% of customers have received a higher than expected bill within the last year



Q: In the past 12 months, how often did you receive an electric bill that was higher than you expected?

Most customers feel they have taken steps to reduce their bill within the past five years

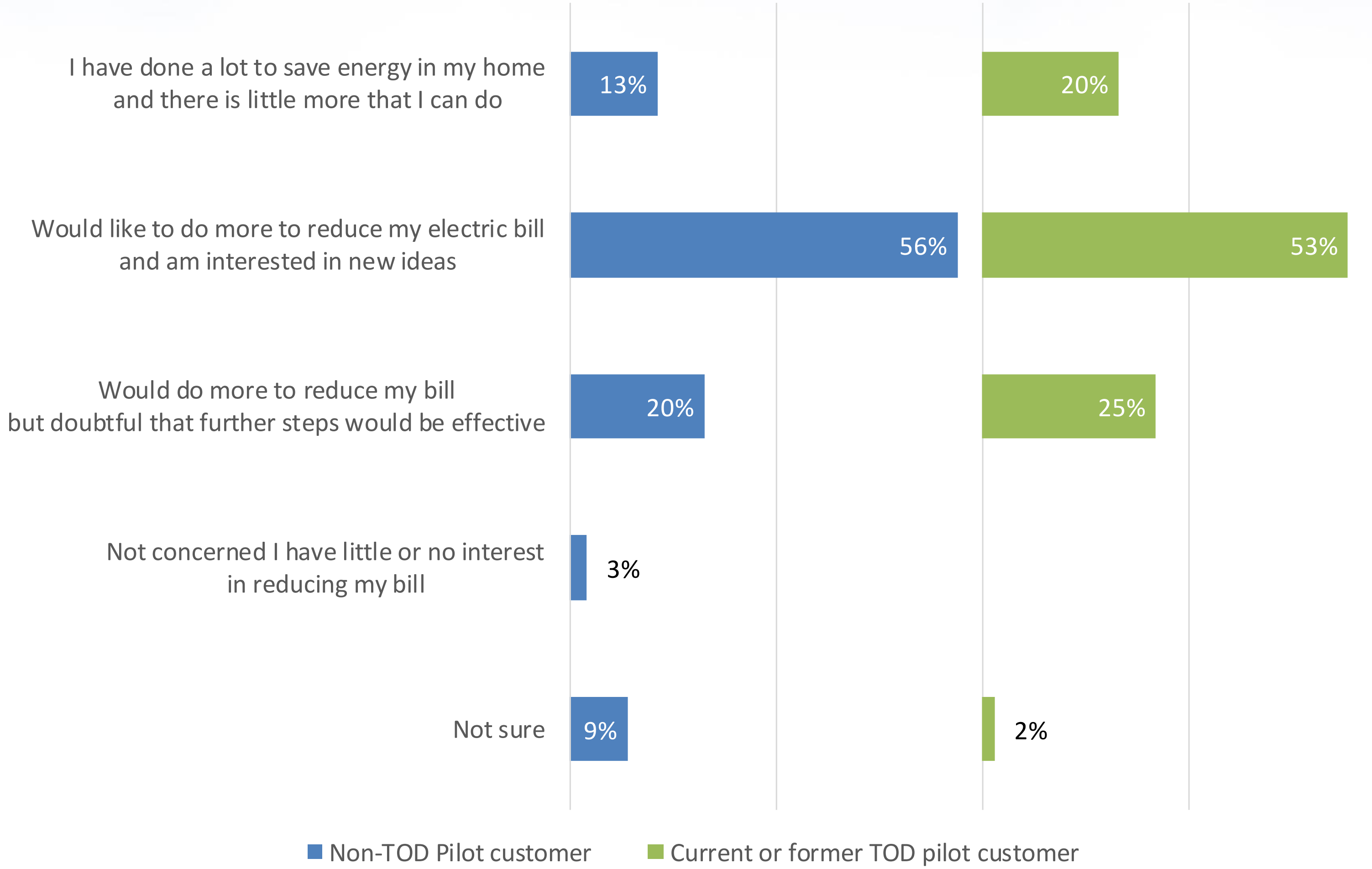


Q: In the past five years, have you taken steps to lower your electric bill by using less electricity?

For TOD customers that have taken steps to reduce their bill, 65% saw results

Q: Did you notice any reductions in your electric bill after taking these steps?

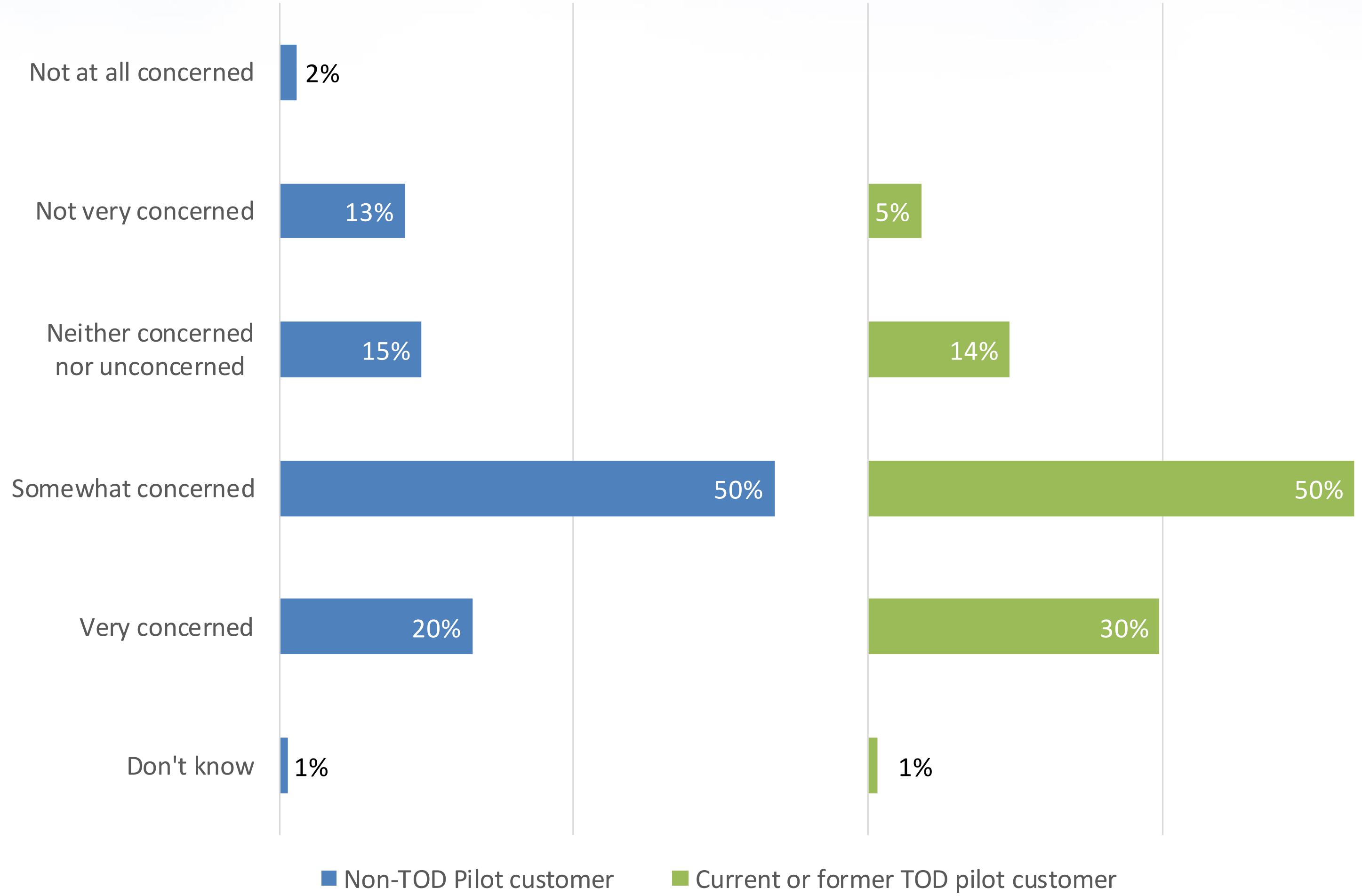
The majority of customers would like to do more, but some don't think there is more they can do



Q: Which of the following statements best describes your current attitude toward reducing your electric bill?

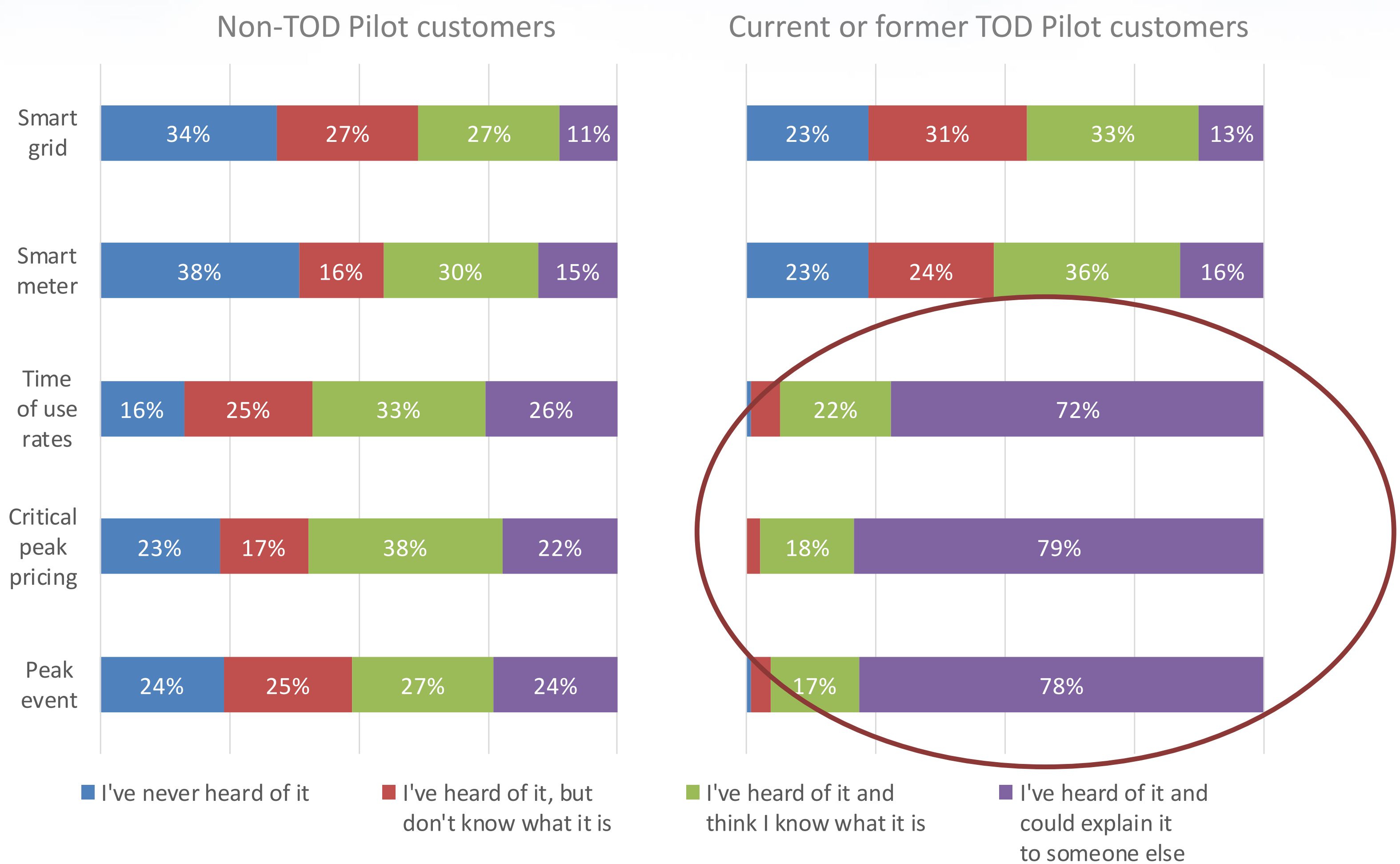
Attachment A

Almost ¾ of customers have concerns about the cost of their electricity in the next five years



Q: Looking ahead five years, how concerned are you about the cost of electricity?

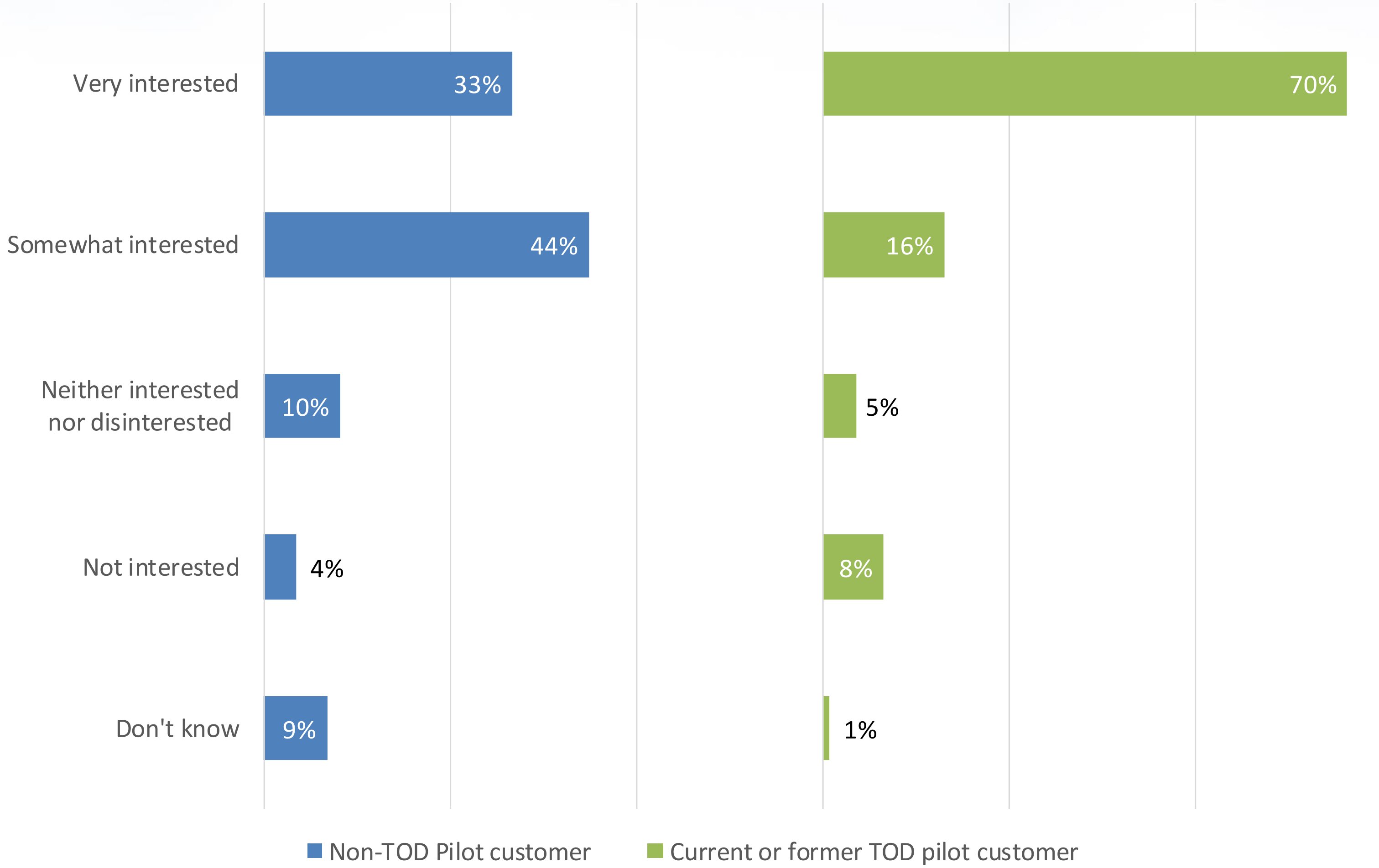
Most customers are aware of terms surrounding TOU rates, but level of understanding varies



Q: How well do you understand the following energy-related terms?

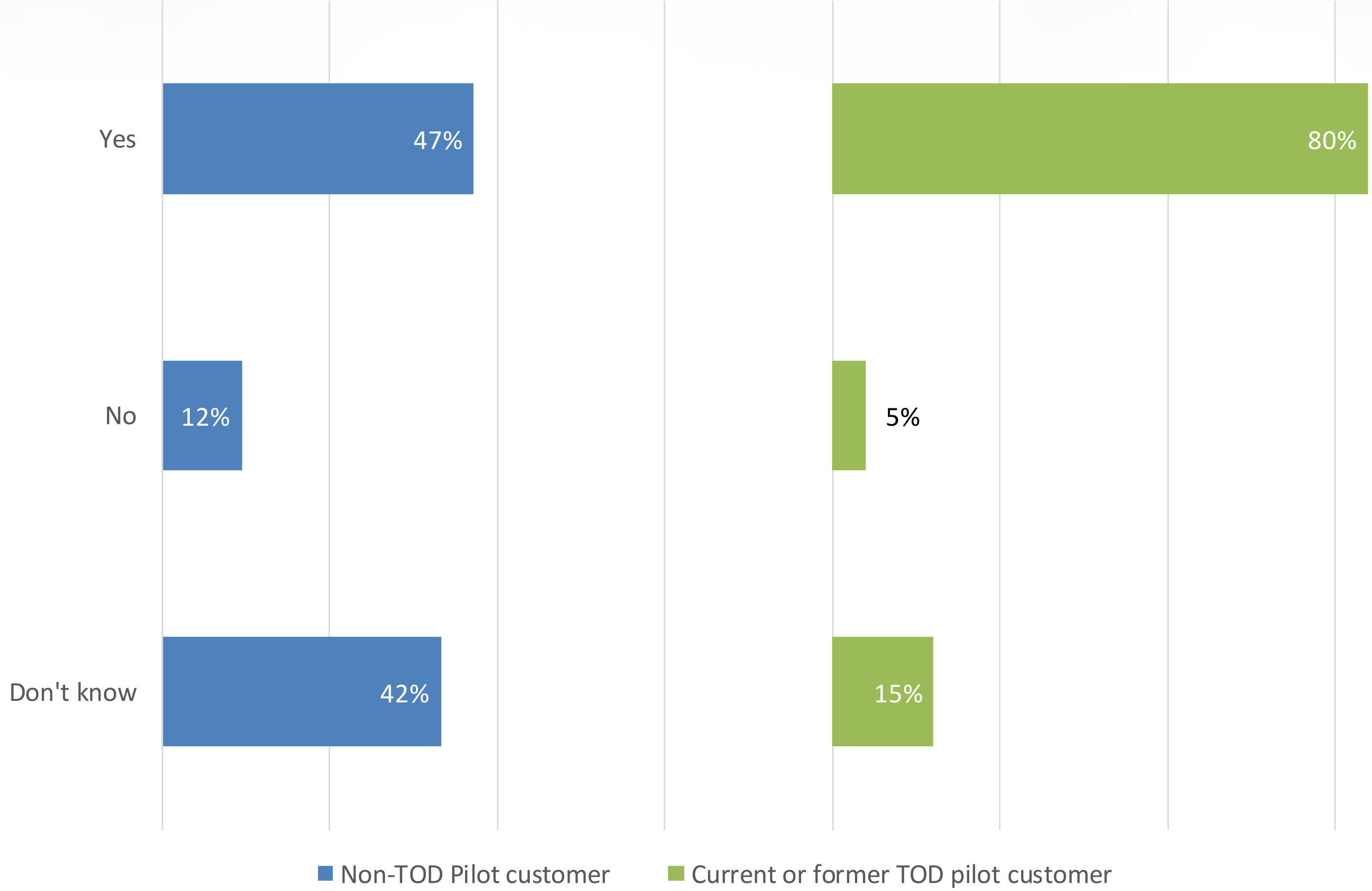
minnesota power
AN ALLETE COMPANY
EnergyForward

The majority of customers are interested in a Time-of-Day rate if it can save them money



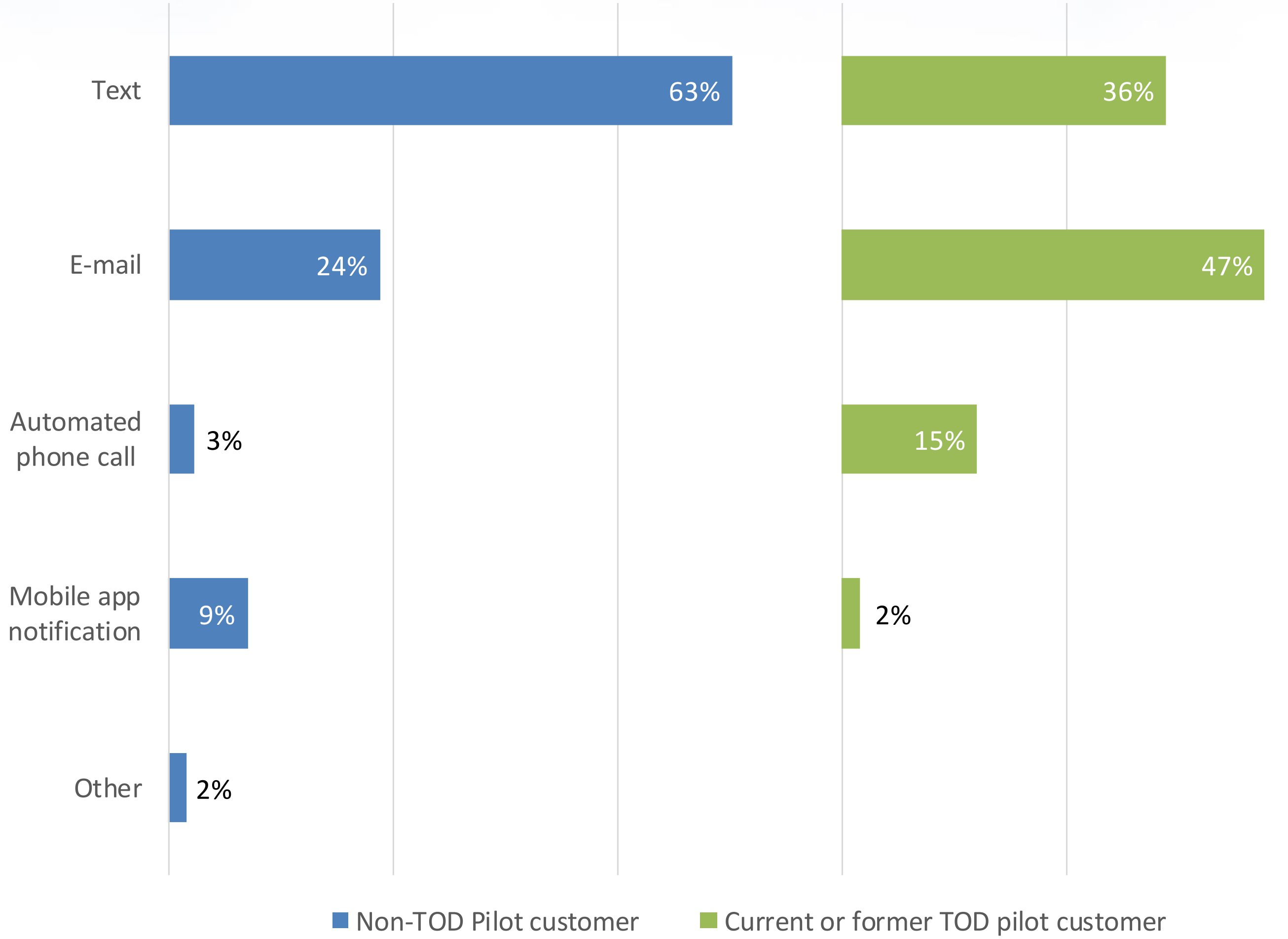
Q: How interested would you be in an optional Minnesota Power time-of-day rate that could help you save money by shifting some of your energy usage to off-peak times like nights and weekends?

Almost half of non-TOD customers and 80% of TOD customers feel they could shift their energy use from season to season



Q: The hours for peak electricity use change from season to season (e.g., winter on-peak is 5-9 p.m., summer on-peak is noon-4 p.m.). If you were on a time-of-day rate, would you be able to shift your energy use each season?

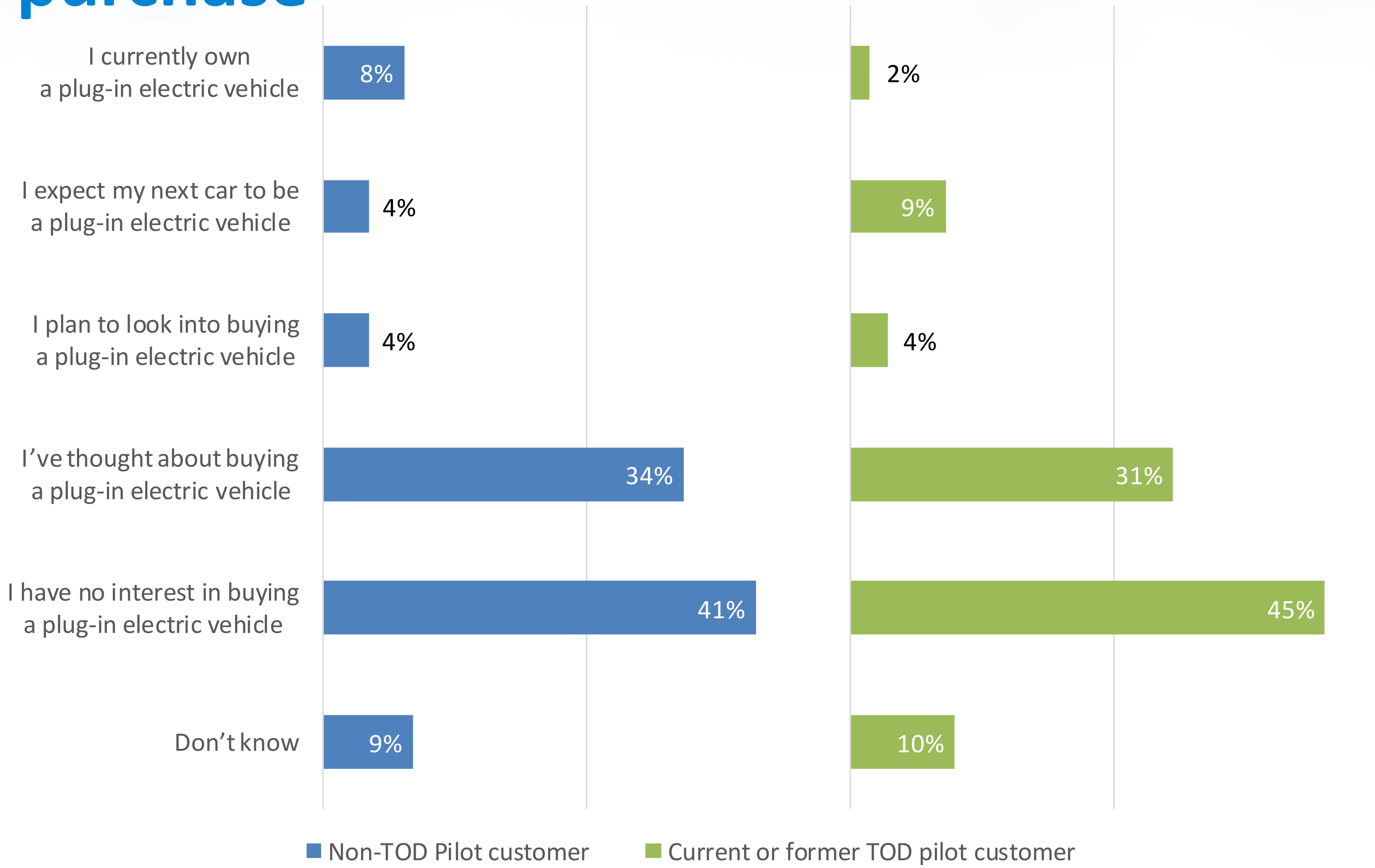
Customers prefer to receive alerts via text or email



Q: What would be your preferred method of communication if you were on a time-of-day rate and Minnesota Power could alert you to an upcoming peak event and provide tips to reduce your bill?

minnesota power
AN ALLETE COMPANY
EnergyForward

Over 10% of respondents currently own or expect to purchase a PEV, over 30% have considered a PEV purchase



Q: Which of the following statements best describes your interest in a plug-in electric vehicle?

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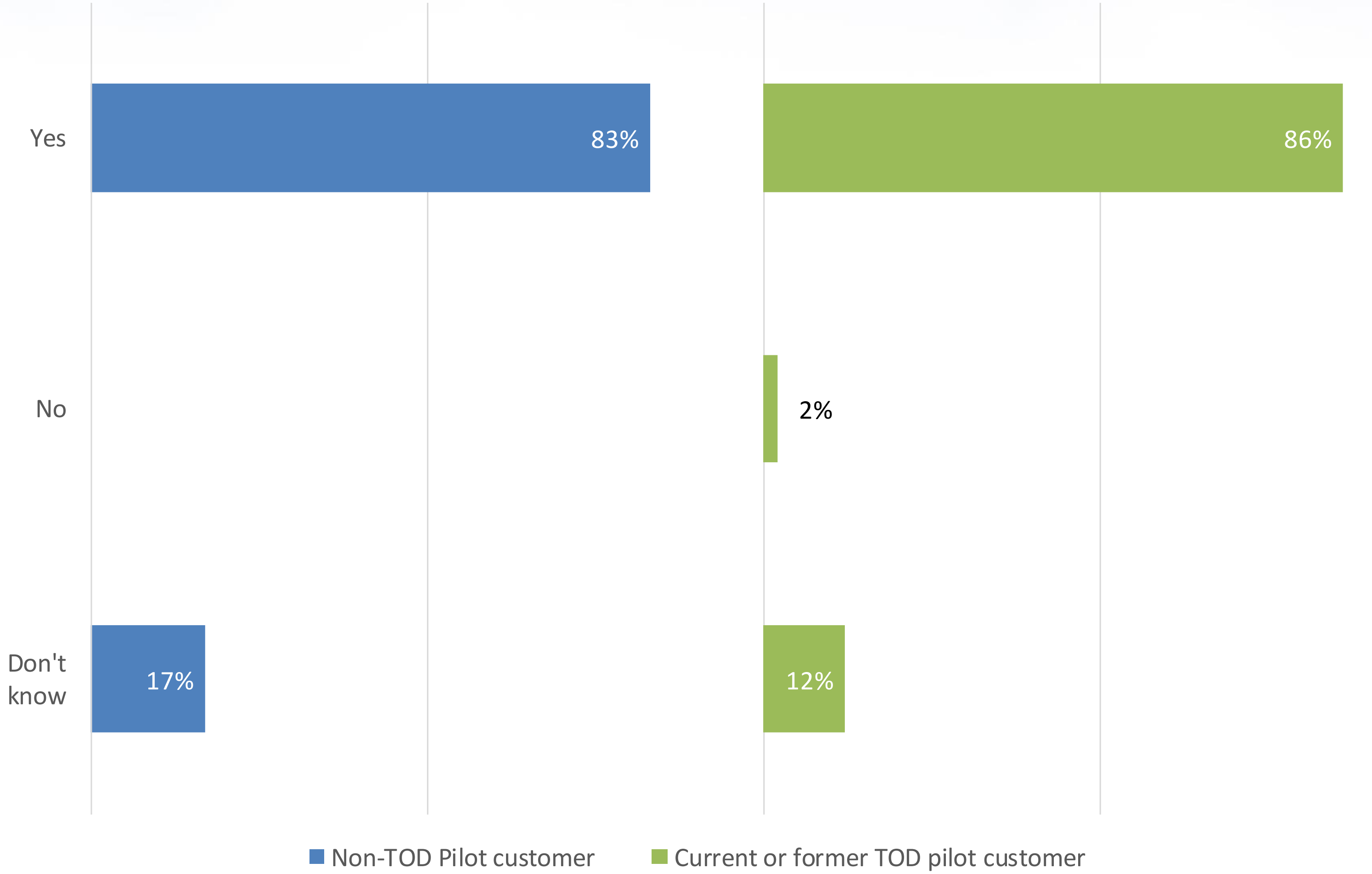
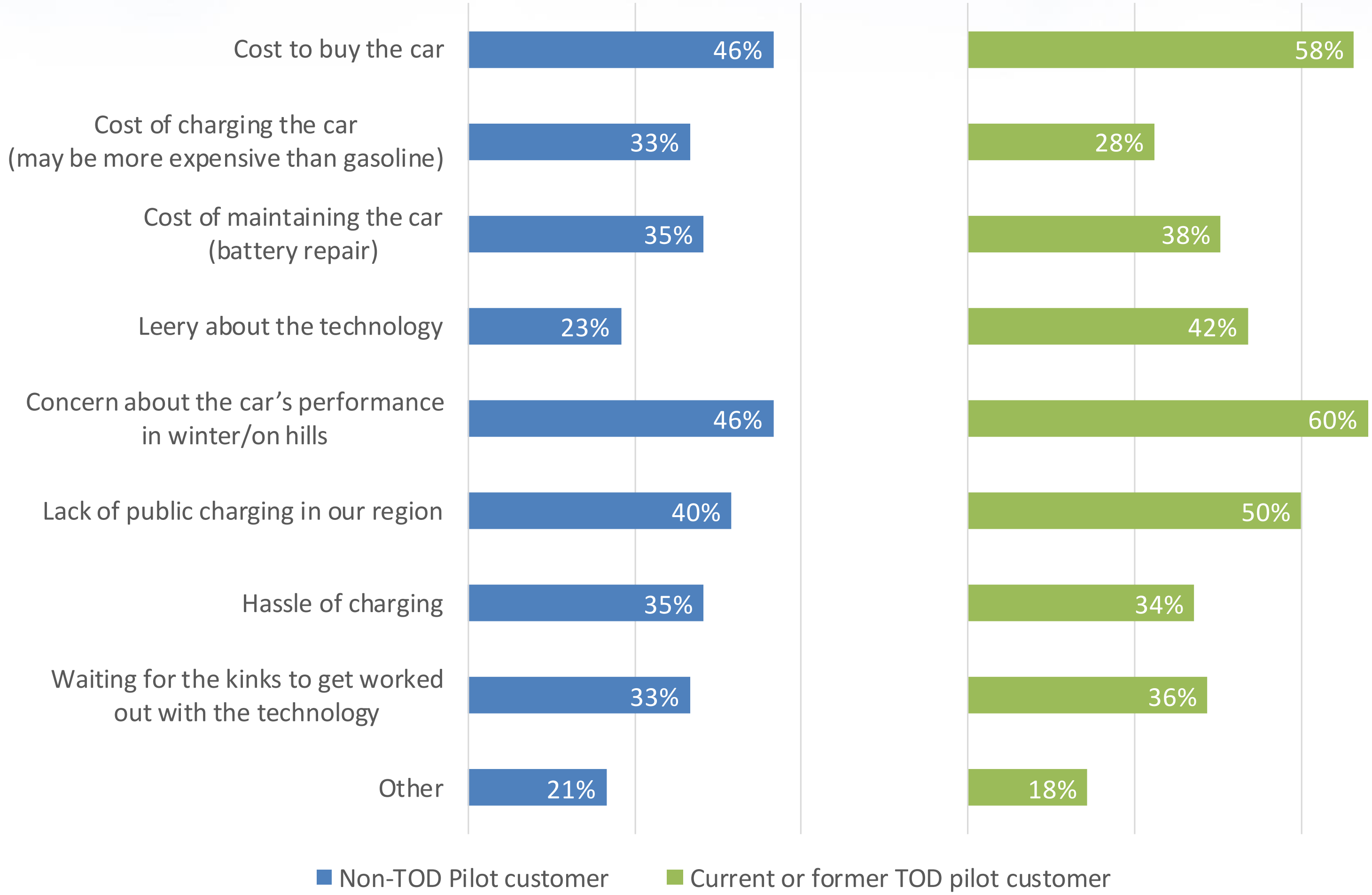
AN ALLETE COMPANY
EnergyForward

A large majority showed interest in TOU rates as a way to save money on PEV charging



Q: If I owned a plug-in electric vehicle, I would be interested in having my household on a time-of-use rate to save money on my charging costs by charging the vehicle during off-peak times.

Cost and performance are top reasons for customers to not be interested in PEV



Q: Why aren't you interested in purchasing a plug-in electric vehicle? [select all that apply]:

minnesota power
AN ALLETE COMPANY
EnergyForward

Survey Response Demographics

- Home Owners vs. Renter
  - Home Owners **93%** | Renters **7%**
- Participants by age range:
  - 18 – 34 **17%** | 35 – 54 **42.4%** | 55 – 65 **25.3%** | 65+ **14.4%** | Prefer Not to Answer <**1%**
- Employment Status:
  - Working: **80.3%** | Retired: **16.2%** | Not Working: **1.7%** | Prefer Not to Answer: **1.7%**
- Children in the Home:
  - Yes **33.8%** |No **67.2%**
- Annual Household Income:
  - <$35K **6.6%** | $35K – 75K **36.7%** | $75K+ **45.9%** | Prefer Not to Answer **10.9%**
- Gender:
  - Male **41.9%** | Female **54.1%** | Prefer Not to Answer **3.9%**
- Location:
  - Greater Duluth **~90%** | Other: ~**10%**
- Current/Past MN Power Time-of-Day Participants
  - **111**

TOU RATE OPTIONS FOR MINNESOTA POWER

LON HUBER

12/10/2018

COST ALLOCATION OPTIONS

Option A: allocation of embedded costs using load duration method

- Allocates embedded costs across time periods based on the load that caused these costs
- (further detail on next slides)

Option B: no allocation of embedded costs

- Treats embedded costs as sunk costs
- Generation and network capacity have already been built
- Future consumption decisions cannot reduce these embedded costs, so costs recovered evenly across all time periods
- (provides a short-run view of marginal cost of service: only LMPs are marginal, all other costs are sunk)

Option C: LMP allocation approach

- Allocates embedded costs across time periods based on LMPs, as these are a readily available and reasonable proxy for load

COST ALLOCATION OPTIONS – DETAIL

MP’s annual residential cost to serve is broken down by component and allocated across 8,760 hours

2018 costs		Option A: Embedded cost allocation Allocated to each hour using:		Rationale	Option B: No embedded cost allocation. Allocated to each hour using:	Rationale	Option C: LMP allocation approach Allocated to each hour using:	Rationale
Capacity	$47m	Generation capacity	MISO load	MP’s generation capacity requirements (imposed by MISO) are driven by its load during summer afternoons when MISO load peaks	Allocated evenly	Costs are sunk, only marginal costs are allocated	MISO LMP (energy price) at MP node	LMPs include generation and transmission cost signals, and are a reasonable proxy for distribution cost signals also
		Transmission capacity	Minnesota Power gross load	Gross load drives the capacity requirements (and thus cost) of MP’s transmission system				
		Distribution capacity	Minnesota Power residential load	Residential peak demand is the key driver of the capacity (and thus cost) of the distribution system in residential areas				
Energy	$31m	MISO LMP (energy price) at MP node		The LMP represents the cost to Minnesota Power of supplying energy to its ratepayers, either through self-generation or purchases through MISO	(as Option A)		(as Option A)	
Customer	$27m	Allocated evenly		These costs (e.g. metering, customer services) do not vary with load so are recovered in part through the monthly Service Charge with remainder shared evenly across all hours	(as Option A)		(as Option A)	

NAVIGANT

PEAK PERIOD OPTIONS

Option 1: Targeted peak periods

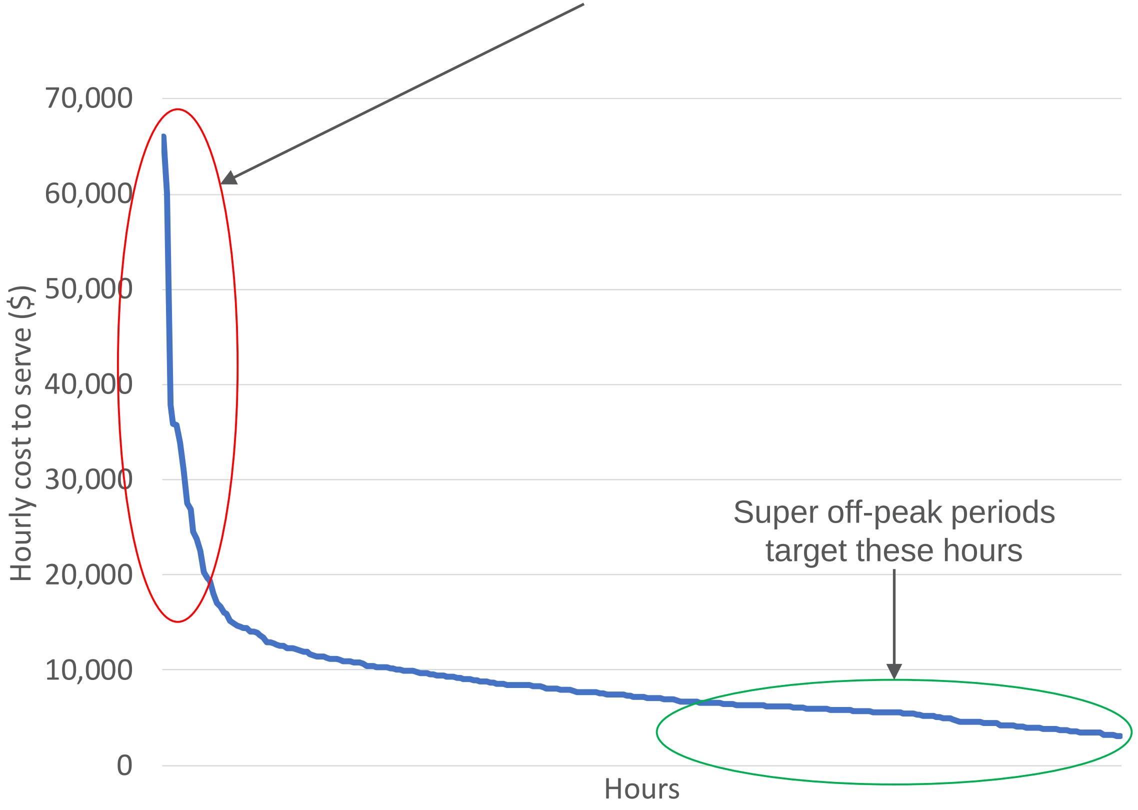
- Allow peak period times to vary by season
- Allow shoulder months with no peak periods

Option 2: Consistent peak periods

- Maintain consistent peak period hours across the year

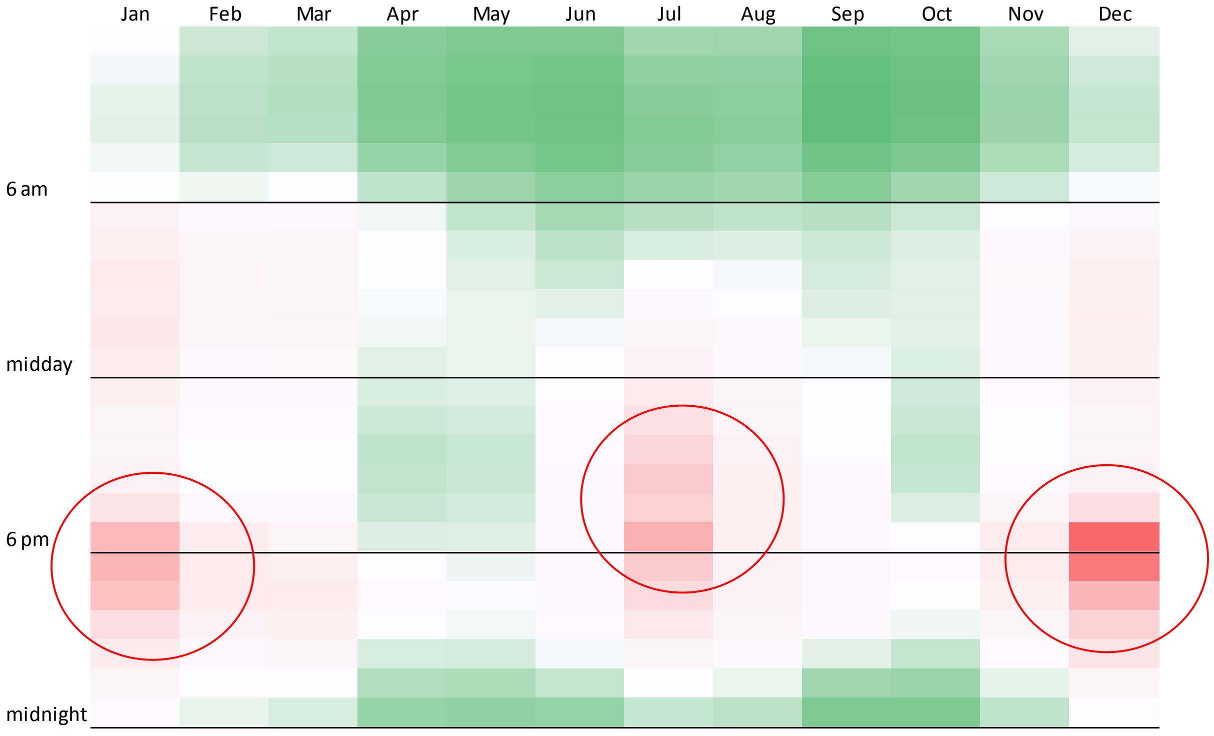
COST TO SERVE BY HOUR

A small number of hours per year have very high cost to serve; peak prices will target these hours



Cost to serve chart shown based on cost allocation option A

Highest cost to serve hours occur winter evenings and summer afternoons



Red = highest cost to serve, **Green** = lowest cost to serve

DETERMINING PEAK TIME PERIODS – OPTION 1 TARGETED PEAKS

We compared the cost to serve load in each hour with the average cost to serve load

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	-16%	-34%	-38%	-55%	-57%	-57%	-47%	-48%	-62%	-61%	-45%	-28%
	-23%	-38%	-41%	-57%	-60%	-61%	-52%	-52%	-65%	-63%	-48%	-34%
	-26%	-39%	-42%	-57%	-61%	-63%	-55%	-54%	-66%	-63%	-49%	-36%
	-27%	-40%	-41%	-56%	-61%	-62%	-56%	-55%	-66%	-63%	-49%	-37%
	-23%	-36%	-34%	-50%	-57%	-60%	-55%	-52%	-61%	-58%	-44%	-32%
6 am	-11%	-24%	-19%	-38%	-49%	-54%	-50%	-47%	-55%	-47%	-34%	-21%
	28%	0%	7%	-23%	-38%	-46%	-41%	-38%	-41%	-35%	-15%	6%
	48%	13%	17%	-18%	-30%	-39%	-31%	-29%	-34%	-29%	-4%	28%
	65%	17%	14%	-20%	-28%	-34%	-19%	-22%	-32%	-28%	-2%	41%
	61%	12%	13%	-21%	-26%	-28%	-3%	-12%	-29%	-28%	-3%	46%
	73%	8%	10%	-23%	-25%	-22%	13%	-4%	-26%	-28%	-1%	40%
midday	54%	4%	3%	-28%	-26%	-17%	34%	5%	-22%	-30%	-2%	38%
	41%	-4%	-3%	-30%	-29%	-12%	64%	13%	-18%	-33%	-9%	32%
	24%	-10%	-10%	-35%	-33%	-8%	106%	24%	-15%	-35%	-13%	23%
	17%	-14%	-16%	-38%	-36%	-7%	157%	31%	-11%	-37%	-15%	16%
	31%	-13%	-13%	-37%	-35%	0%	215%	36%	-5%	-36%	-10%	26%
	95%	4%	-2%	-35%	-32%	4%	180%	39%	0%	-29%	21%	121%
6 pm	288%	54%	18%	-29%	-29%	7%	333%	43%	5%	-12%	60%	654%
	308%	65%	44%	-15%	-25%	2%	207%	31%	4%	-8%	56%	586%
	254%	65%	57%	-8%	-20%	-3%	131%	27%	3%	-14%	40%	310%
	124%	34%	36%	-18%	-23%	-11%	68%	18%	-5%	-24%	16%	172%
	59%	6%	10%	-31%	-32%	-22%	24%	-3%	-28%	-37%	-7%	90%
	13%	-13%	-17%	-43%	-44%	-37%	-14%	-25%	-47%	-49%	-26%	19%
midnight	-9%	-26%	-31%	-50%	-52%	-51%	-36%	-40%	-57%	-57%	-38%	-15%

162% above average (i.e. more than double) cost to serve during winter peak

136% above average (i.e. more than double) cost to serve during summer peak

Red = highest cost to serve, **Green** = lowest cost to serve

- Clear **seasonal pattern** in cost to serve
  - Apr-Jun and Sep-Oct: cost to serve never significantly above average, with no hour more than 7% above average
  - Jul-Aug and Nov-Mar: cost to serve significantly above average in afternoons (summer) and evenings (winter), with at least one hour 43% above average
- Based on this, suggest
  - **two month summer peak** (July – August)
  - **five month winter peak** (November – March)
- Previous experience suggests **four hour peak periods** achieve optimal load reduction and shifting
- Identified the four hour blocks with the highest average to cost serve

DETERMINING PEAK TIME PERIODS – OPTION 2 CONSISTENT PEAKS

We compared the cost to serve load in each hour with the average cost to serve load

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	-16%	-34%	-38%	-55%	-57%	-57%	-47%	-48%	-62%	-61%	-45%	-28%
	-23%	-38%	-41%	-57%	-60%	-61%	-52%	-52%	-65%	-63%	-48%	-34%
	-26%	-39%	-42%	-57%	-61%	-63%	-55%	-54%	-66%	-63%	-49%	-36%
	-27%	-40%	-41%	-56%	-61%	-62%	-56%	-55%	-66%	-63%	-49%	-37%
	-23%	-36%	-34%	-50%	-57%	-60%	-55%	-52%	-61%	-58%	-44%	-32%
6 am	-11%	-24%	-19%	-38%	-49%	-54%	-50%	-47%	-55%	-47%	-34%	-21%
	28%	0%	7%	-23%	-38%	-46%	-41%	-38%	-41%	-35%	-15%	6%
	48%	13%	17%	-18%	-30%	-39%	-31%	-29%	-34%	-29%	-4%	28%
	65%	17%	14%	-20%	-28%	-34%	-19%	-22%	-32%	-28%	-2%	41%
	61%	12%	13%	-21%	-26%	-28%	-3%	-12%	-29%	-28%	-3%	46%
	73%	8%	10%	-23%	-25%	-22%	13%	-4%	-26%	-28%	-1%	40%
midday	54%	4%	3%	-28%	-26%	-17%	34%	5%	-22%	-30%	-2%	38%
	41%	-4%	-3%	-30%	-29%	-12%	64%	13%	-18%	-33%	-9%	32%
	24%	-10%	-10%	-35%	-33%	-8%	106%	24%	-15%	-35%	-13%	23%
	17%	-14%	-16%	-38%	-36%	-7%	157%	31%	-11%	-37%	-15%	16%
	31%	-13%	-13%	-37%	-35%	0%	215%	36%	-5%	-36%	-10%	26%
	95%	4%	-2%	-35%	-32%	4%	180%	39%	0%	-29%	21%	121%
6 pm	288%	54%	18%	-29%	-29%	7%	333%	43%	5%	-12%	60%	654%
	308%	65%	44%	-15%	-25%	2%	207%	31%	4%	-8%	56%	586%
	254%	65%	57%	-8%	-20%	-3%	131%	27%	3%	-14%	40%	310%
	124%	34%	36%	-18%	-23%	-11%	68%	18%	-5%	-24%	16%	172%
	59%	6%	10%	-31%	-32%	-22%	24%	-3%	-28%	-37%	-7%	90%
	13%	-13%	-17%	-43%	-44%	-37%	-14%	-25%	-47%	-49%	-26%	19%
midnight	-9%	-26%	-31%	-50%	-52%	-51%	-36%	-40%	-57%	-57%	-38%	-15%

61% above average cost to serve during peak period

- Consistent peak time period across the year
- Selected peak period hours to capture as many individual high cost to serve hours as possible, while ensuring peak price signal was not excessively diluted

Red = highest cost to serve, **Green** = lowest cost to serve

DETERMINING SUPER OFF-PEAK TIME PERIODS – OPTIONS 1 AND 2

Cost heatmap shows that overnight hours are consistently below average cost to serve

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
	-16%	-34%	-38%	-55%	-57%	-57%	-47%	-48%	-62%	-61%	-45%	-28%
	-23%	-38%	-41%	-57%	-60%	-61%	-52%	-52%	-65%	-63%	-48%	-34%
	-26%	-39%	-42%	-57%	-61%	-63%	-55%	-54%	-66%	-63%	-49%	-36%
	-27%	-40%	-41%	-56%	-61%	-62%	-56%	-55%	-66%	-63%	-49%	-37%
	-23%	-36%	-34%	-50%	-57%	-60%	-55%	-52%	-61%	-58%	-44%	-32%
6 am	-11%	-24%	-19%	-38%	-49%	-54%	-50%	-47%	-55%	-47%	-34%	-21%
	28%	0%	7%	-23%	-38%	-46%	-41%	-38%	-41%	-35%	-15%	6%
	48%	13%	17%	-18%	-30%	-39%	-31%	-29%	-34%	-29%	-4%	28%
	65%	17%	14%	-20%	-28%	-34%	-19%	-22%	-32%	-28%	-2%	41%
	61%	12%	13%	-21%	-26%	-28%	-3%	-12%	-29%	-28%	-3%	46%
	73%	8%	10%	-23%	-25%	-22%	13%	-4%	-26%	-28%	-1%	40%
midday	54%	4%	3%	-28%	-26%	-17%	34%	5%	-22%	-30%	-2%	38%
	41%	-4%	-3%	-30%	-29%	-12%	64%	13%	-18%	-33%	-9%	32%
	24%	-10%	-10%	-35%	-33%	-8%	106%	24%	-15%	-35%	-13%	23%
	17%	-14%	-16%	-38%	-36%	-7%	157%	31%	-11%	-37%	-15%	16%
	31%	-13%	-13%	-37%	-35%	0%	215%	36%	-5%	-36%	-10%	26%
	95%	4%	-2%	-35%	-32%	4%	180%	39%	0%	-29%	21%	121%
6 pm	288%	54%	18%	-29%	-29%	7%	333%	43%	5%	-12%	60%	654%
	308%	65%	44%	-15%	-25%	2%	207%	31%	4%	-8%	56%	586%
	254%	65%	57%	-8%	-20%	-3%	131%	27%	3%	-14%	40%	310%
	124%	34%	36%	-18%	-23%	-11%	68%	18%	-5%	-24%	16%	172%
	59%	6%	10%	-31%	-32%	-22%	24%	-3%	-28%	-37%	-7%	90%
	13%	-13%	-17%	-43%	-44%	-37%	-14%	-25%	-47%	-49%	-26%	19%
midnight	-9%	-26%	-31%	-50%	-52%	-51%	-36%	-40%	-57%	-57%	-38%	-15%

- Applied two criteria:
  1. Cost to serve must be below average
  2. Consistent super off-peak hours across the year

46% below average cost to serve for super off-peak hours

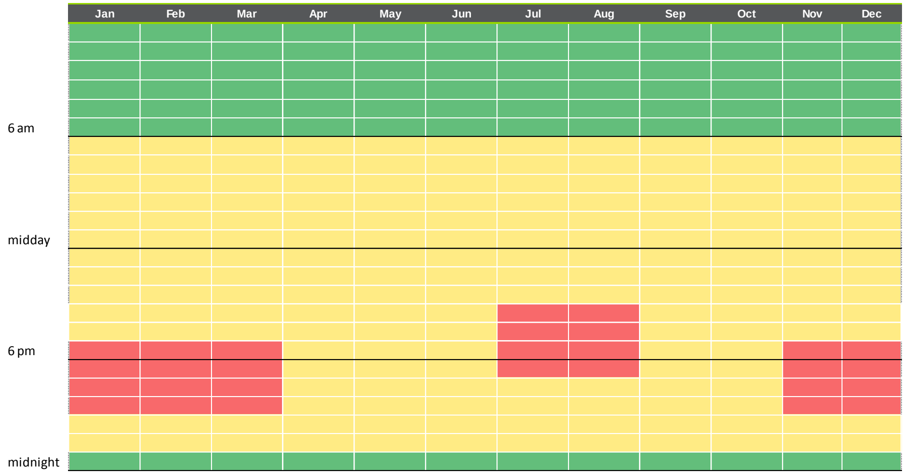
Red = highest cost to serve, **Green** = lowest cost to serve

NAVIGANT

TOD TIME PERIODS

Option 1: Targeted peak periods

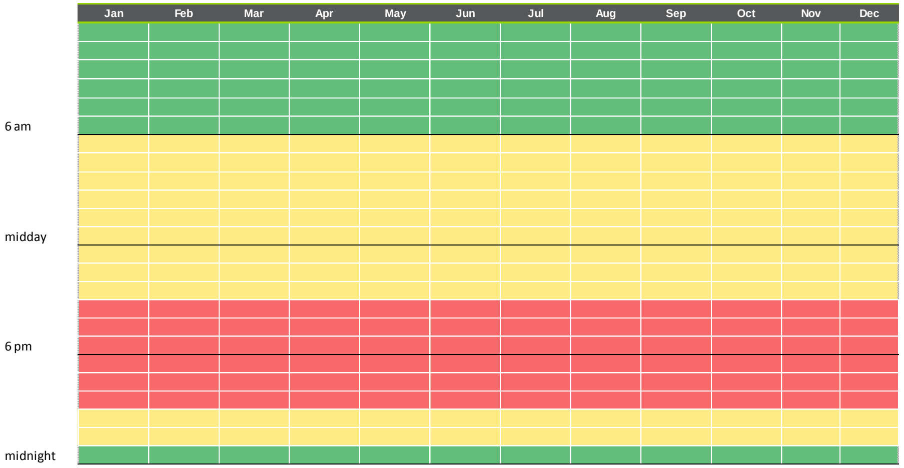
	Winter (Nov – Mar)	Summer (Jul – Aug)	Shoulder (Apr – Jun, Sept – Oct)
Super off-peak	11pm – 6am	11pm – 6am	11pm – 6am
Off-peak	6am – 5pm and 9pm – 11 pm	6am – 3pm and 7pm – 11 pm	6am – 11pm
Peak	5pm – 9pm	3pm – 7pm	n/a



* Shoulder season prices apply on all weekends and public holidays

Option 2: Consistent peak periods

	All year
Super off-peak	11pm – 6am
Off-peak	6am – 3pm and 9pm – 11 pm
Peak	3pm – 9pm



NAVIGANT

TOD RATES – ADDERS / DISCOUNTS TO EXISTING BLOCK TARIFFS

Option 1A: embedded costs allocated, targeted peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-2.4	29%
Off-peak	-0.1	64%
Peak	6.4	7%

Option 1B: no embedded cost allocation, targeted peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-0.8	29%
Off-peak	0.1	64%
Peak	0.7	7%

Option 1C: LMP allocation, targeted peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-1.9	29%
Off-peak	0.4	64%
Peak	1.8	7%

Option 2A: embedded costs allocated, consistent peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-2.4	29%
Off-peak	-0.1	53%
Peak	2.7	18%

Option 2B: no embedded cost allocation, consistent peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-0.8	29%
Off-peak	0.1	53%
Peak	0.4	18%

Option 2C: LMP allocation, consistent peaks

	Adder or discount (c/kWh)	Share of hours
Super off-peak	-1.9	29%
Off-peak	0.4	53%
Peak	1.2	18%

TOD RATES – AS AVERAGE RATES

Option 1A: embedded costs allocated, targeted peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	7.2	29%
Off-peak	9.5	64%
Peak	16.0	7%

Option 1B: no embedded cost allocation, targeted peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	8.8	29%
Off-peak	9.7	64%
Peak	10.3	7%

Option 1C: LMP allocation, targeted peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	7.6	29%
Off-peak	10.0	64%
Peak	11.4	7%

Option 2A: embedded costs allocated, consistent peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	7.2	29%
Off-peak	9.5	53%
Peak	12.3	18%

Option 2B: no embedded cost allocation, consistent peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	8.8	29%
Off-peak	9.7	53%
Peak	10.0	18%

Option 2C: LMP allocation, consistent peaks

	Average rate (c/kWh)	Share of hours
Super off-peak	7.6	29%
Off-peak	9.9	53%
Peak	10.8	18%

INDICATIVE MARGINAL COSTS

Indicative marginal costs

Function	Source	Cost (2020, $/kW-year)	Cost (2020, c/kWh)*
Transmission	Mendota Group analysis of 30 US utilities (2014)	$25	1.7
Distribution	Mendota Group analysis of 30 US utilities (2014)	$52	3.5
Generation Capacity	Gross CT Cost of New Entry (LRZ 1)	$95	6.5
Energy	Residential load weighted LMP, 6-10 pm (2020)		4.3
Total Rate during Peak Hours			**16.0**

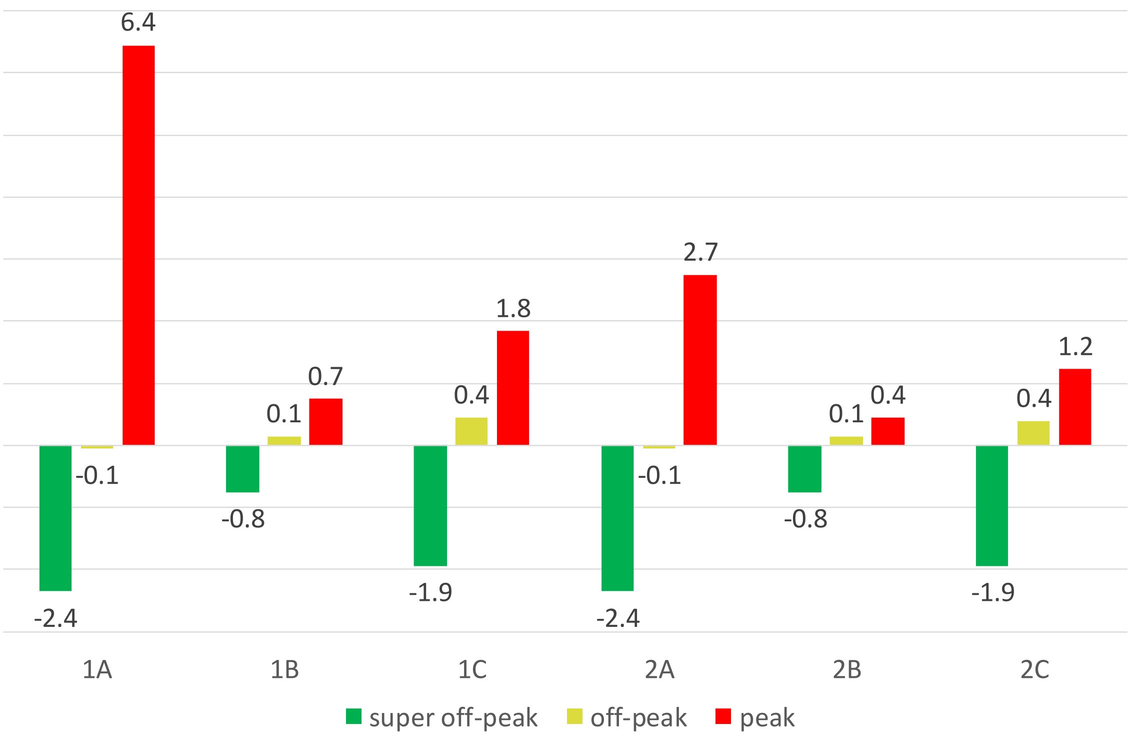
Sample marginal costs ($/kW-yr)

	Transmission	Distribution
Otter Tail Power (2016)	$72	$31
Xcel Energy (2014)	$14	$39
Mendota Group analysis average value (2014)	$22	$46

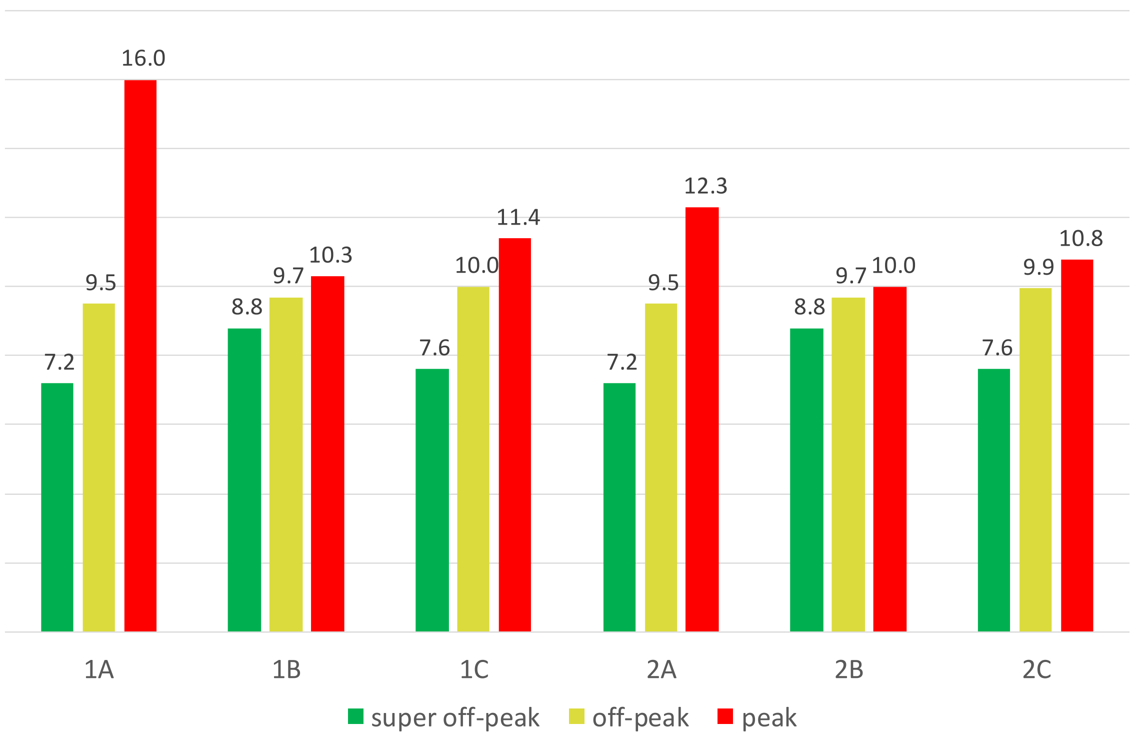
* Fixed costs spread across a four hour peak period

TOD RATES – CHARTS

TOD rates – as adders / discounts



TOD rates – as average rates



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TOD RATE OPTIONS – BILL IMPACT

	kWh	1A $ p.a.	%	1B $ p.a.	%	1C $ p.a.	%	2A $ p.a.	%	2B $ p.a.	%	2C $ p.a.	%
RC_1	3,496	-2	-1%	-1	0%	0	0%	-2	-1%	0	0%	0	0%
RC_2	6,087	1	0%	0	0%	2	0%	-1	0%	0	0%	2	0%
RC_3	8,335	2	0%	0	0%	2	0%	1	0%	0	0%	3	0%
RC_4	12,604	9	1%	2	0%	10	1%	11	1%	3	0%	11	1%
RC_5	16,307	7	0%	0	0%	8	0%	4	0%	2	0%	8	0%
RC_6	27,054	-19	-1%	-8	0%	-10	0%	-30	-1%	-7	0%	-11	0%
RN_1	4,018	3	1%	0	0%	2	0%	1	0%	0	0%	2	0%
RN_2	6,984	5	1%	1	0%	5	1%	5	1%	1	0%	6	1%
RN_3	8,020	3	0%	-1	0%	1	0%	0	0%	0	0%	1	0%
RN_4	14,994	1	0%	-2	0%	1	0%	-4	0%	-1	0%	1	0%
RN_5	16,545	34	2%	6	0%	22	1%	30	2%	7	0%	23	1%
RN_6	28,127	-18	-1%	-9	0%	-13	0%	-31	-1%	-8	0%	-14	0%
RW_1	4,198	-2	0%	-1	0%	0	0%	-1	0%	0	0%	0	0%
RW_2	7,692	-5	-1%	-2	0%	-3	0%	-6	-1%	-2	0%	-3	0%
RW_3	12,099	17	1%	3	0%	13	1%	16	1%	4	0%	14	1%
RW_4	18,000	7	0%	-2	0%	2	0%	-3	0%	-1	0%	1	0%
RW_5	27,931	33	1%	6	0%	26	1%	26	1%	8	0%	27	1%
RW_6	95,093	-5	0%	-5	0%	26	0%	7	0%	4	0%	34	0%

Initial bill impacts are muted

- Adder / discount structure of TOD rates means that overall usage level doesn’t drive bill impacts
- Calculated bill impacts customer profiles in MP’s Load Research study (as used in most recent rate design)
- For these profiles, no bill impact exceeds 2%
- Further bill impact analysis using individual customer data will be carried out in the future

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THANK YOU

LON HUBER
928.380.5540

Minnesota Power Advanced Time of Day Rate
Meeting 3: December 10th, 2018

Mill City Museum – ADM Room
710 S 2nd Street, Minneapolis, MN 55401

10:00am – 2:00pm

Meeting Notes

1. **What are the strengths of what was presented?**
   - General design and approach– 3 periods seems right, pricing seems justified based on underlying costs
   - On the right track – targeted, shorter peak. People will be better able to respond
   - Simpler than existing pilot
   - Seems like it will benefit most people
   - 6 different options provides flexibility to figure out the best solution
2. **What improvements would stakeholders suggest (not necessarily to be figured out by 2/1/19)?**
   - Look at keeping the 4-hour peak, but bridge the summer and winter so there are two seasons instead of three
   - Look at option of a 5-hour peak, but year-round
   - Look at making the super off-peak an hour shorter (interest in maximizing super off-peak shift)
   - Show how a higher peak:off-peak ratio would affect bills
   - More on treatment (or exclusion) of different customer groups if doing opt-out – net metering, electric heat, etc.
     - How this would work for net metering customers (depends on monetary vs. kWh crediting)
   - Discuss whether IBR would discontinue, and if so, how
   - Marketing and education – some discussion of a rough plan (but acknowledging that it doesn't need to be finalized before rate is approved)
   - Ensure a large enough differential between on and off-peak periods to encourage behavior change
   - Better understand the significance of allocation decisions in the model (e.g., MISO for generation capacity vs. MP)

  - Deeper dive into different user profiles – in each scenario, how would different cases impact particular users?

3. **How well do the draft recommendations align to the design principles? (and/or are there suggested changes to the design principles?)**
   - Costs and benefits – acknowledge benefits might be difficult to measure. Don't want to see a proposal where costs outweigh benefits (incremental program costs/benefits). Not including metering, but education, marketing, admin.
   - Low-income – can look more into it. Question of whether bill impacts warrant indemnification. Need to discuss IBR as part of this.
     - Would like to see a transitional plan, at least. Could provide a buffer.
     - Issue of missing people who aren't on LIHEAP assistance.
     - Question about renters with multiple tenants on a single meter – how will they be addressed?
   - EE/RE/GHG – looking good from the standpoint of three TOU periods. Just need to optimize this.
   - Rates that accurately reflect costs of energy – good
   - Opt-out – some difference of opinion
     - One perspective -- Weigh costs vs. benefits. Opt-out is default, but open to MP determining if it's not appropriate.
     - Another perspective -- Would like to see everybody on this rate
   - Access and tools – must-have down the road
     - Would like stronger customer interface with data – can customer actually interact with their usage data?
     - Co-market efficiency programs and technologies that can help with responding to TOU periods
   - "TOD plus" products (CPP, PTR) – stakeholders still open to considering as an opt-in, but not necessary (would require either a CPP with a separate TOD design, or a PTR on top)
4. **Does a TOD rate seem worth it for MN Power? Why or why not?**
   - Yes – a step forward in creating a modern rate design. Open question about the benefit we're hoping to get.
     - Question about timing – might be 5-10 years before market prices are high enough to make this product worthwhile
     - Multiple benefits – peak shaving, integration of RE during off-peak.
   - No – maybe not enough benefits to justify.
5. **What additional information would you like to see (or not see)?**
   - Peak ratios in B and C didn't seem high enough to warrant further detail
   - Option A3 – in between A1 and A2
   - Rough plan for marketing and customer engagement
6. **What, if anything, would cause you to oppose a TOD rate?**
   - If costs are high and benefits are small
   - If differential between periods is not high enough to solicit a worthwhile behavioral response

- If some advocates are strongly against, may make it difficult for similar advocates to disagree
- Question about inclusion of IBR – some would like to keep it, some would like to see it go away
    - Against IBR – complexity increases with TOD; disincentivizes beneficial electrification; may be better ways to incentivize conservation; with more RE on the system, want TOD over IBR to incentivize usage during certain periods.
    - Some discussion about impacts on low users (especially low-income low users)
    - IBR is arguably less fair than TOD
- Marketing and outreach – want to see a defined plan to start with.
    - What about for opt-out? Means education about the change, and how to respond including suggestions to maximize savings. Maybe an option to revert if not comfortable.
- Opt-in approach – make the effort of designing the rate worthwhile. Impact on benefits vs. costs.
- No plan for net metering customers. Open to discussing a plan, but would like to see something.
    - How many net metering customers does MP have?

7. Reflection, Wrap-up, and Next Steps

- Need to prioritize analytics, and what the next steps are
- Medically necessary customers should be excluded from being automatically opted in
- What are the most important things to address in the February 1st filing?
    - Specific proposal on the timing and pricing, including seasonality (if including)
    - Raise as many issues now before there is a tariff up for discussion – get the Commission's input upfront
    - Balance what can be done in a quality fashion before Feb. 1st.
    - Acknowledge that net metering will need to be addressed
- What will be in the filing?
    - Learnings from this process
    - Can't file a tariff yet
- Another meeting?
    - Would be most helpful to see a concrete idea to offer constructive feedback
    - Happy to review before filing, but not necessary
    - Preferable to have a webinar meeting
    - Goal – come back with 1-2 options that are fully baked

Minnesota Power Advanced Time of Day Rate
Meeting 4 (Webinar): January 11th, 2019

10:00am – 11:30am

Please join us by using this Zoom link

Meeting Objectives:

1. Solicit feedback on the final rate design options moving forward
2. Address any outstanding questions
3. Understand next steps for Minnesota Power's proposed Time of Day rates

Draft Agenda

10:00 – 10:15 am	Welcome, Intro's, Recap from Meeting 3
10:15 – 11:15 am	Presentation and Q&A: Revised Rate Designs • What did stakeholders like? • Any major concerns?
11:15 – 11:30 am	Next Steps • Address outstanding issues and questions
11:30am	ADJOURN

MINNESOTA POWER TOU RATE DESIGN
JANUARY STAKEHOLDER WEBINAR

LON HUBER

JANUARY 2019

INTRODUCTION

1. Updated rate options
2. Bill impact analysis and update
3. Exclusions
4. General Feedback

COST ALLOCATION OPTIONS

Option A: allocation of embedded costs using load duration method

- Allocates embedded costs across time periods based on the load that caused these costs
- (further detail on next slides)

Option B: no allocation of embedded costs

Not progressed further

- Treats embedded costs as sunk costs
- Generation and network capacity have already been built
- Future consumption decisions cannot reduce these embedded costs, so costs recovered evenly across all time periods
- (provides a short-run view of marginal cost of service: only LMPs are marginal, all other costs are sunk)

Option C: LMP allocation approach

Not progressed further

- Allocates embedded costs across time periods based on LMPs, as these are readily available and reasonable proxy for load

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COST ALLOCATION OPTIONS – DETAIL

MP's annual residential cost to serve is broken down by component and allocated across 8,760 hours

2018 costs		Option A: Embedded cost allocation Allocated to each hour using:		Rationale	Option B: No embedded cost allocation. Allocated to each hour using:	Rationale	Option C: LMP allocation approach Allocated to each hour using:	Rationale
Capacity	$47m	Generation capacity	MISO load	MP's generation capacity requirements (imposed by MISO) are driven by its load during summer afternoons when MISO load peaks	Allocated evenly	Costs are sunk, only marginal costs are allo[illegible]ted	MISO LMP (energy price) at MP node	LMPs include generation and transmissio[illegible] cost signals[illegible] are a reas[illegible]e proxy fo[illegible]tribution cost [illegible]als also
		Transmission capacity	Minnesota Power gross load	Gross load drives the capacity requirements (and thus cost) of MP's transmission system				
		Distribution capacity	Minnesota Power residential load	Residential peak demand is the key driver of the capacity (and thus cost) of the distribution system in residential areas				
Energy	$31m	MISO LMP (energy price) at MP node		The LMP represents the cost to Minnesota Power of supplying energy to its ratepayers, either through self-generation or purchases through MISO	(as Opt[illegible]A)		(as [illegible]n A)	
Customer	$27m	Allocated evenly		These costs (e.g. metering, customer services) do not vary with load so are recovered in part through the monthly Service Charge with remainder shared evenly across all hours	(as Option A)		(as Option A)	

Not progressed further

Not progressed further

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PEAK PERIOD OPTIONS

Option 1: Four hour targeted peak periods, with shoulder

- Four hour peak periods that vary by season
- Shoulder months with no peak periods
  - 5pm – 9pm from Nov to Mar (five months)
  - 3pm – 7pm from Jul to Aug (two months)
  - No peaks from Apr to Jun and Sep to Oct (five months)

Option 2: Six hour consistent peak periods

- Six hour peak period across the year
  - 3pm – 9pm

(NEW) Option 3: Four hour targeted peak periods, no shoulder

- Four hour peak periods that vary by season
- No shoulder months
  - 5pm – 9pm from Sep to May (nine months)
  - 3pm – 7pm from Jun to Aug (three months)

(NEW) Option 4: Five hour consistent peak periods

- Five hour peak period across the year
  - 4pm – 9pm

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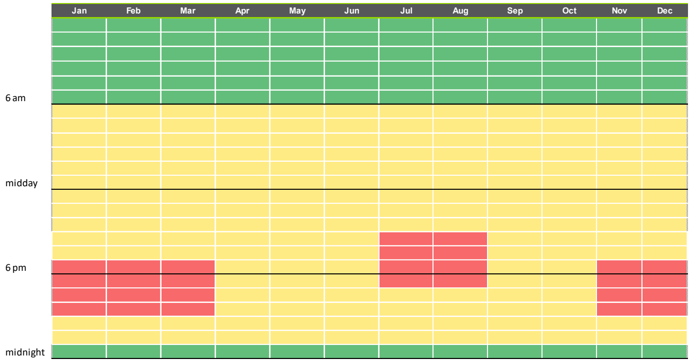
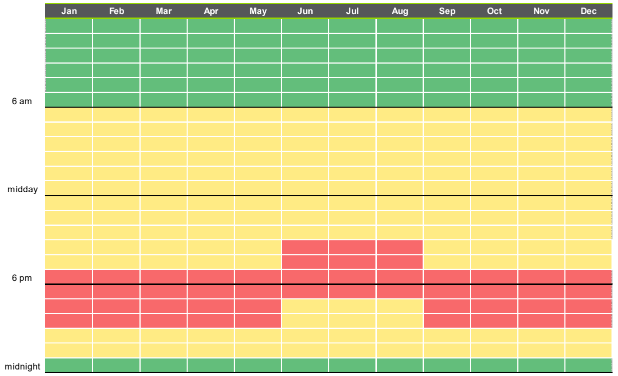
PEAK PERIOD OPTIONS

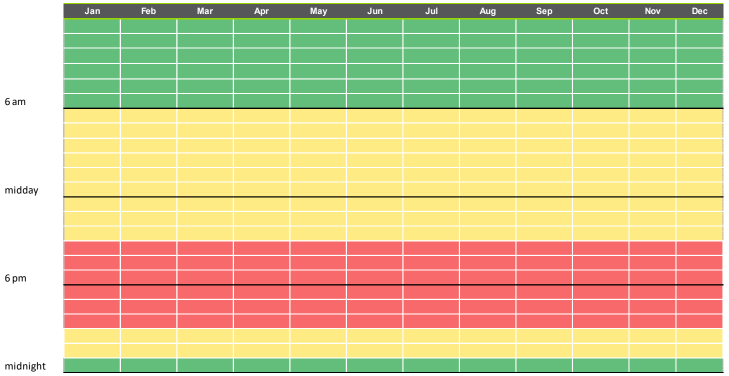
Option 1: Four hour targeted peak periods, with shoulder



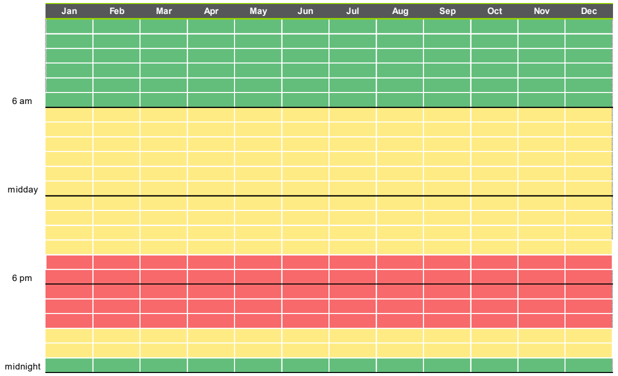
(NEW) Option 3: Four hour targeted peak periods, no shoulder



Option 2: Six hour consistent peak periods



(NEW) Option 4: Five hour consistent peak periods



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SUPER OFF-PEAK PERIOD OPTIONS

Original option: seven hour super off-peak

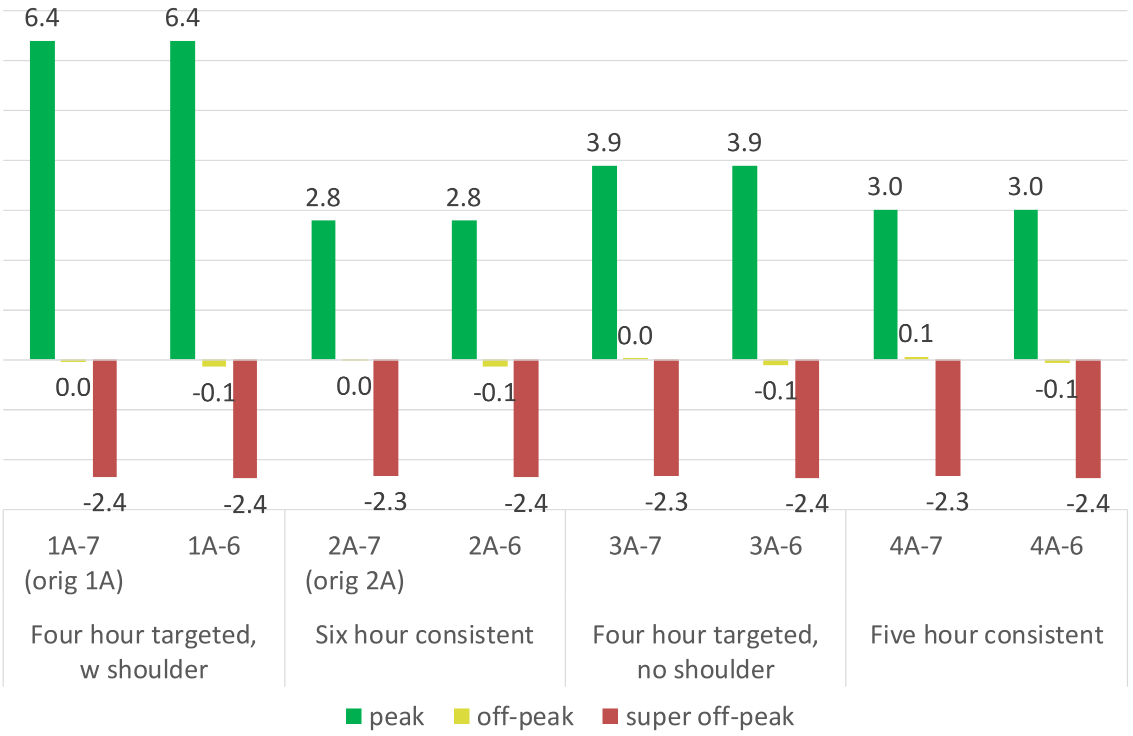
- 11pm – 6am

(NEW) Alternate option: six hour super off-peak

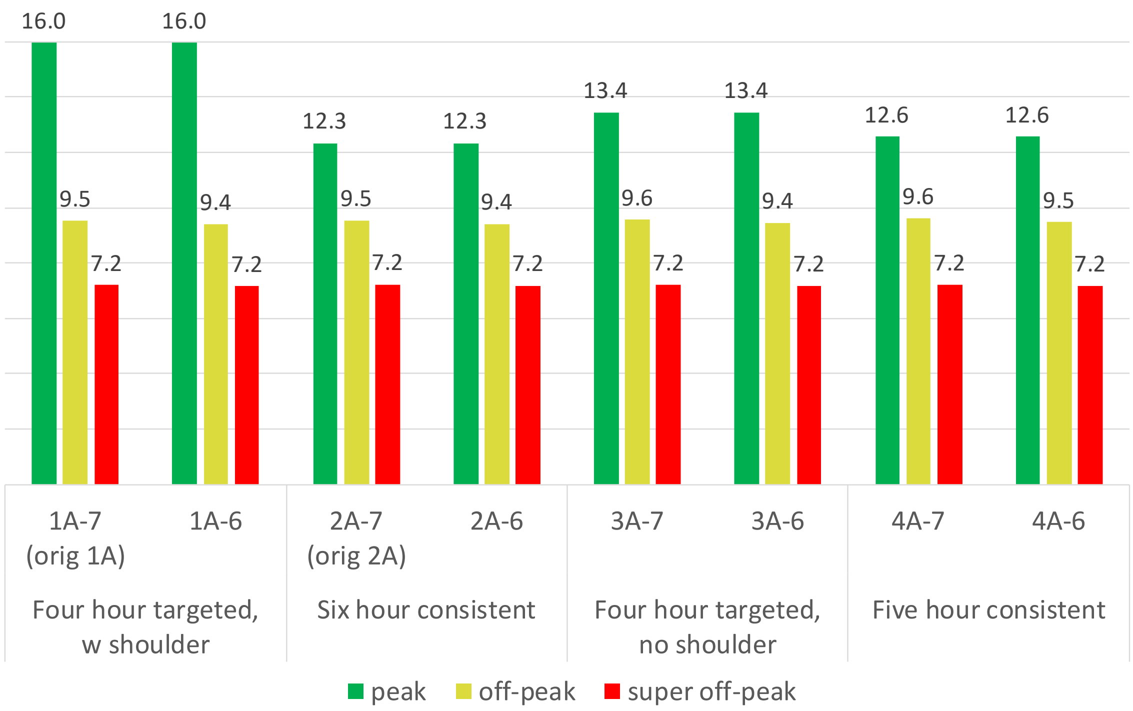
- 11pm – 5am

TOD RATES – CHARTS

TOD rates – as adders / discounts



TOD rates – as average rates



-7 = seven hour super off-peak (original option)
-6 = six hour super off-peak (new option)

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TOD RATE OPTIONS – IMPACT OF DIFFERENT COST STRUCTURE

Cost structure (2018 costs)

	Actual costs	Alternate costs
Capacity	$47m	$50m
Energy	$31m	$35m
Customer	$27m	$20m

TOD rates – option 4A-7 (five hour peak, 4pm – 9pm, year round)

	Actual costs	Alternate costs
Peak	12.6c	12.8c
Off-peak	9.6c	9.6c
Super off-peak	7.2c	7.0c

TOD RATE OPTIONS – HOW WOULD A HIGHER PEAK RATIO AFFECT BILLS?

	kWh	1A-7 $ p.a.	%	2A-7 $ p.a.	%	1-high diff $ p.a.	%
RC_1	3,496	-2	-1%	-2	-1%	**-3**	**-1%**
RC_2	6,087	1	0%	-1	0%	**3**	**1%**
RC_3	8,335	2	0%	1	0%	**5**	**1%**
RC_4	12,604	9	1%	11	1%	**19**	**2%**
RC_5	16,307	7	0%	4	0%	**15**	**1%**
RC_6	27,054	-19	-1%	-30	-1%	**-33**	**-1%**
RN_1	4,018	3	1%	1	0%	**6**	**2%**
RN_2	6,984	5	1%	5	1%	**11**	**2%**
RN_3	8,020	3	0%	0	0%	**6**	**1%**
RN_4	14,994	1	0%	-4	0%	**4**	**0%**
RN_5	16,545	34	2%	30	2%	**67**	**4%**
RN_6	28,127	-18	-1%	-31	-1%	**-31**	**-1%**
RW_1	4,198	-2	0%	-1	0%	**-3**	**-1%**
RW_2	7,692	-5	-1%	-6	-1%	**-8**	**-1%**
RW_3	12,099	17	1%	16	1%	**33**	**3%**
RW_4	18,000	7	0%	-3	0%	**15**	**1%**
RW_5	27,931	33	1%	26	1%	**67**	**2%**
RW_6	95,093	-5	0%	7	0%	**-1**	**0%**

New option 1-high diff

	1-high diff	1A-7
Peak	22.3c	16.0c
Off-peak	9.4c	9.5c
Super off-peak	5.1c	7.2c

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EXCLUSIONS?

1. Medically dependent customers
2. ?

NET METERING

- Significant metering and billing challenges

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FEEDBACK?

- Any questions, concerns, comments?

Minnesota Power Advanced Time of Day Rate
Meeting 4 (Webinar): January 11th, 2019

10:00am – 11:30am

Meeting Description: This is the fourth and final meeting of this series. In the first two meetings, the group learned about Minnesota Power's metering infrastructure and load profile and worked to develop a set of design principles for the TOD rate. In the third meeting, Minnesota Power presented a set of draft TOD rate options, which the group evaluated against the design principles. The group has asked Minnesota Power to come back in this final webinar meeting with 1-2 fully developed rate design options for final feedback.

Meeting Objectives:

1. Solicit feedback on the final rate design options moving forward
2. Address any outstanding questions
3. Understand next steps for Minnesota Power's proposed Time of Day rates

Meeting Notes

1. **Clarifying Questions:**
    a. Why does shifting from 7 hr to 6 hr super off peak not change the off-peak rate?
        i. Hours have similar costs, so when you take an hour out, it doesn't change the average cost.
    b. Slide 9 -- Surprised at how little shifted between the two cost structures, in terms of the rates.
        i. Oliver and Lon will follow-up by email. Could be that it's the option to bridge on-peak across the entire year, so impacts are muted.
    c. Slide 10 – can you unpack this?
        i. These are different load profiles, but they're averaged into these annual usage buckets and geographic zones
        ii. This shows the impact if a customer does NOT change behavior at all. Impacts for customers that shift load will be higher.
    d. Exclusions – haven't made any final decisions
    e. For net metering – can't you net meter by production within each TOU period?
        i. Request is to net meter within the TOD periods; question is whether the metering technology and billing software can allow for that.
        ii. MP will check into this and follow up with the group.

2. **Discussion Questions:**
    a. Exclusions/inclusions?
        i. Net metering -- estimate about 200 customers. Need to determine how to bucket them to make sure net metering is fair.
        ii. If company is proposing advanced metering, and cost recovery on that, then it seems like it should be expected that these billing issues will be worked out.
    b. What do stakeholders like?
    c. Where are there remaining areas for improvement?
        i. MN Power EV rate has a longer off-peak period and has a lower price per kWh (4 cents). Given how low LMP's are in Minnesota over night, 7 cents seems too high.
            1. This is up to date, but slightly historic in terms of renewable energy build out.
            2. MP load is pretty flat compared to other systems.
            3. Could there be a more forward-looking analysis that assumes more renewables, so that this rate is accurate in the future?
        ii. Differential and options
            1. One perspective -- Price ratios for consistent peak periods aren't sharp enough – leads to options 1A and 3A. 3A is easier to market and educate, but less of a differential.
            2. Another perspective -- Like the five hour consistent option for getting customer engagement.
            3. A third perspective – see advantages of 5 hour consistent, but like a slightly higher peak rate.
            4. Forward-looking design would help to spread out the differential.
            5. Lon -- Option 3 is still within the realm of reason to have customers respond, based on experience from other utilities.
            6. Difficult to increase the differential based on the load profile. Very little system peaking needs.
        iii. Benefits of a TOD rate
            1. What are the huge benefits of this going into the future?
            2. What's the impact on load for 1A and 3A? Is one more impactful than the other?
                a. Pretty hard to tell, but see an incremental response rate from a 12 cents peak to a 14 or 16 cents rate.
            3. How does this change with a more forward-looking analysis?
                a. More focused peak, lower off peak rate
        iv. Education
            1. Current rate is pretty complicated, so not as many concerns about that piece of it.
        v. EV rate – off peak is lower because on-peak period is so much longer.
        vi. Option not on the screen – blend of option 4 and 1 – has "no-peak" seasons in Spring and Fall, but peak period is consistent when it does occur in Summer and Winter
    d. Conclusions

i. Desire for a forward-looking analysis that takes into account more renewables on the system
ii. New option 5 concept – less complexity, which is good, but decision has to be around system peak, schedule, and prices – needs to be a package
iii. Still concerns about whether this is worthwhile.
iv. Is one of these options better than the status quo? Perspectives of the group include the following:
    1. Option 3, 4 and 5 are all workable and probably better than status quo
    2. Without seeing impacts to peak, conflicted about whether a TOD rate is worth the effort
    3. Could live with 3, 4, or 5. Not sure if it's worth it.
    4. Can add value through TOD+ options
v. Concern about customers changing their behavior

Minnesota Power's Time of Day Rate Customer Info Share
Pier B Resort (800 W. Railroad Street, Duluth, MN 55802)
October 30, 2018
6 – 7:30 PM

Agenda

6:00 Refreshments

6:10 Welcome and Introductions

6:15 Presentation from Minnesota Power

6:45 Small Group Exercise

7:15 Large Group Discussion

7:30 End

Minnesota Power's Time of Day Rate Customer Info Share
Cass Gilbert Depot (200 First Street NW, Little Falls, MN 56345)
November 1, 2018
6 – 7:30 PM

Agenda

6:00 Refreshments

6:10 Welcome and Introductions

6:15 Presentation from Minnesota Power

6:45 Small Group Exercise

7:15 Large Group Discussion

7:30 End

Small Group Exercise Responses

<u>What appliances in your home consume the most electricity?</u>

- Refrigerators, old appliances like freezers
- Electric heat
- Hot water heater
- TV, phone charger, radio, etc.
- Dishwasher
- Water pump
- Electric Vehicle
- Clothes dryer
- Air conditioner
- Electric heat

<u>What could you do to shift your household's energy usage from peak periods to off-peak periods?</u>

- Do laundry in the evenings and on the weekends
- Shift baking to off-peak times
- Turn down the heat during peak times or electric heat
- One participant mentioned that it was easier to shift usage to off-peak times prior to retirement but is much more challenging now that she's retired
- Set dishwasher to run overnight
- Set smart washing machine/dryer to run off-peak
- Put irrigation (water pump) on overnight timer
- Shifting some electric appliances to gas saves money
- Installing LEDs help reduce energy load
- Could charge EV at night during off-peak period
- One customer has an electric lawn mower and has shifted to mowing the lawn on weekends

<u>Would you rather have more variation in period pricing (3-4) or less (2)?</u>

- Two periods are easy to remember
- If there are too many periods, people will have a hard time following the period changes
- CPP events have been clearly communicated by Minnesota Power
- As long as you know about the event the day before, it's easy to plan for it and adjust usage accordingly
- A peak period that starts later and ends earlier would be helpful (9 am to 9 pm was suggested)
- It's nice that holidays are considered off-peak

- If there are better prices with deeper discount because of more periods and they are clearly communicated/set ahead of time I'm fine with more
- As long as I know what they are I can adjust my times for different seasons/periods
- Starting the off-peak period sooner would be helpful, 10:00 pm is too late
- It would be helpful to have a super off-peak period for charging EVs

Could you more easily shift your usage during different seasons of the year? (i.e. summer hours vs. winter hours)

- Structuring the rate differently between different seasons would be complicated
- It would be helpful if MP was also able to provide customers with the opportunity to control loads remotely in case they were not aware of an event (examples included a mini split system, thermostat, etc.)
- Some customers would be interested in MP controlling their loads
- I'm retired and have the time available and flexibility for changes in seasons/periods
- One customer who participated in the pilot program commented that he had to go off the program because there were too many CPP events during a cold snap in the winter. It eliminated any chance for cost savings
- Warmer temperatures allow more flexibility
- Seasonal shifting of load didn't seem to be a problem for customers with gas heat

Would you be more likely to participate if you were guaranteed to save money?

- There needs to be an opportunity for cost savings in order for people to want to participate and actually shift energy usage
- The number of CPP event called during the last year on MP's time of day pilot program seemed reasonable to attendees on the rate
- One participants felt that she felt the CPP events were necessary in getting people to shift their loads. If the price isn't high enough, people won't do it
- Customers participating in the pilot program said that they saved a lot of money when the program first started and less since the changes were made
- Overall, they feel like they're still saving money on the rate, even if there are a lot of CPP events
- I would have no interest if I wasn't going to save money – otherwise what is the benefit for me if all customers don't have to change their behavior and I'm still penalized financially
- It would be helpful to know how much money you saved by participating in the rate
- When the pilot program first started, participants saw a lot of costs savings and changed their behaviors accordingly. After the program adjustments, it was hard to notice any savings
- Money savings in the motivation for customers to participate in this program
- A comparison of your usage at that time last year would be helpful for customers to make informed decisions about participation in this type of program

Would you be more likely to participate if you had the option to exit the rate at any time?

- A whole year is a long time to commit to a program if it doesn't end up working for you
- Leaving the rate at any time would be helpful, especially for those who get laid off seasonally (i.e. construction workers, etc.)
- It would be helpful if MP had some comparison tools that let you see how much you would pay on each rate based on your usage history
- It would also be helpful to know how much your rate would go up if you didn't shift your usage at all. One participant thought this might deter people from participating in the rate
- It would be helpful to see a comparison each month
- It would be better to have an option to leave if after a few bills you decide it's not right for you

How would you prefer to receive notifications about different events (i.e. peak events, season changes, etc.)

- Notifications in the current time of day pilot program are delivered via text, phone and email
- Participants like that there are so many notification options
- Everyone felt that notifications about CPP events need to be the day before at a minimum
- Customers who are current participants in the pilot program said that they are typically able to predict when a CPP event is going to occur based on weather patterns
- Participants said viewing all of their MP information (bills, rates, program options) in a mobile app would be ideal
- Text messaging would be convenient

Overall, would you be interested in this type of a program?

- One participant said he is exploring solar at his home and this program seems to fit nicely with solar generation. He feels that a time of day rate would encourage more solar generation
- One customer was also interested in how this rate could be paired with a Tesla Powerwall and expressed interest in using this type of rate for EV charging in the off-peak hours
- Participants who were already enrolled in the time of day pilot program reported that they like to continue to be on the rate
- Some participants feel that this rate should be mandatory if its beneficial to the system
- Electric Vehicle owners would prefer this option (generally) over the costs of installing a second meter (cost eliminates any savings)
- Flexibility is important
- Simplicity is key in this type of program

Minnesota Power Time-of-Day Info Share

Pier B Resort
Duluth, MN
October 30, 2018

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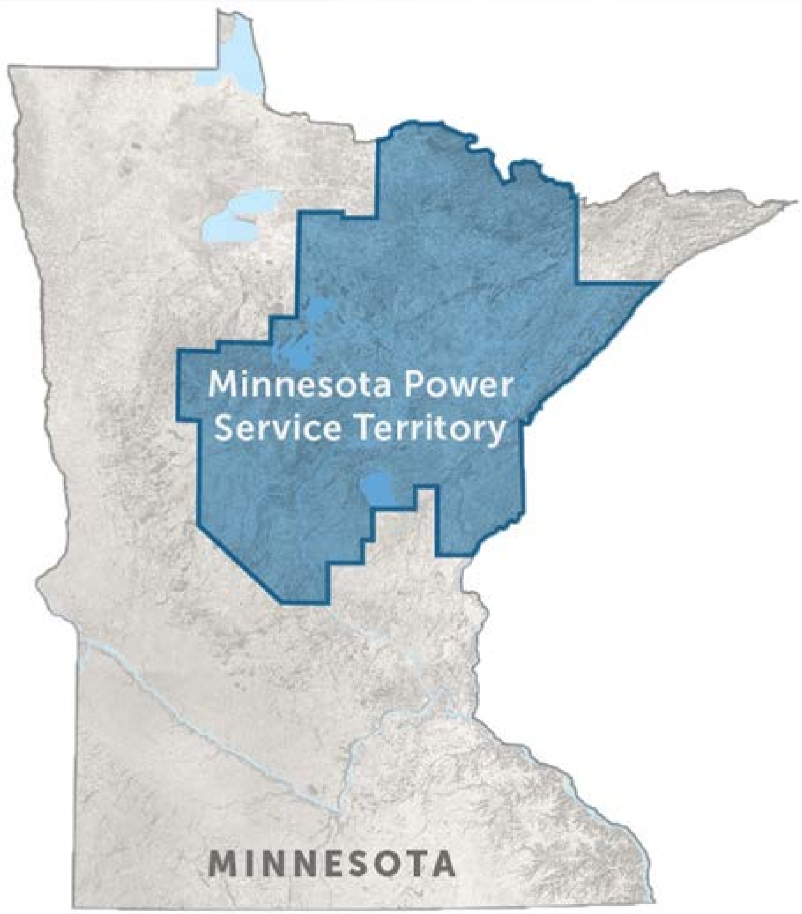
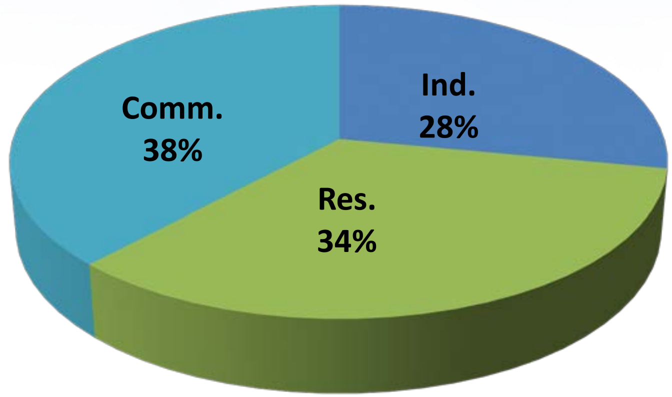
Agenda

- Overview of Minnesota Power and the Electric System
- What are Time-of-Day Programs?
- Minnesota Power's Time-of-Day Pilot Program
- Discussion and Next Steps

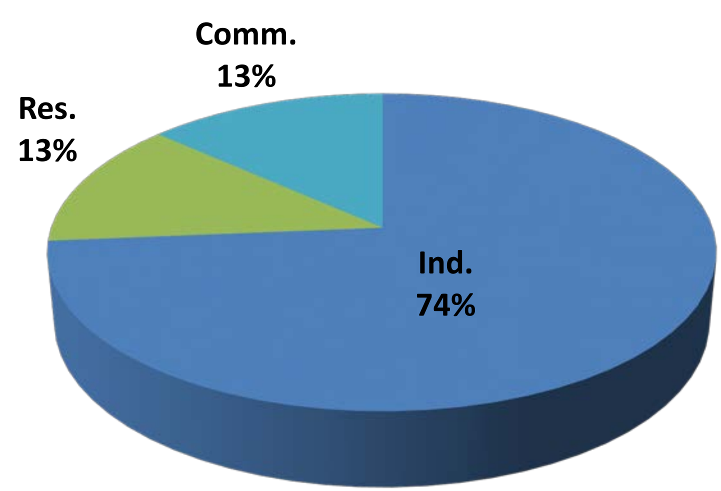
Minnesota Power's System



US Average



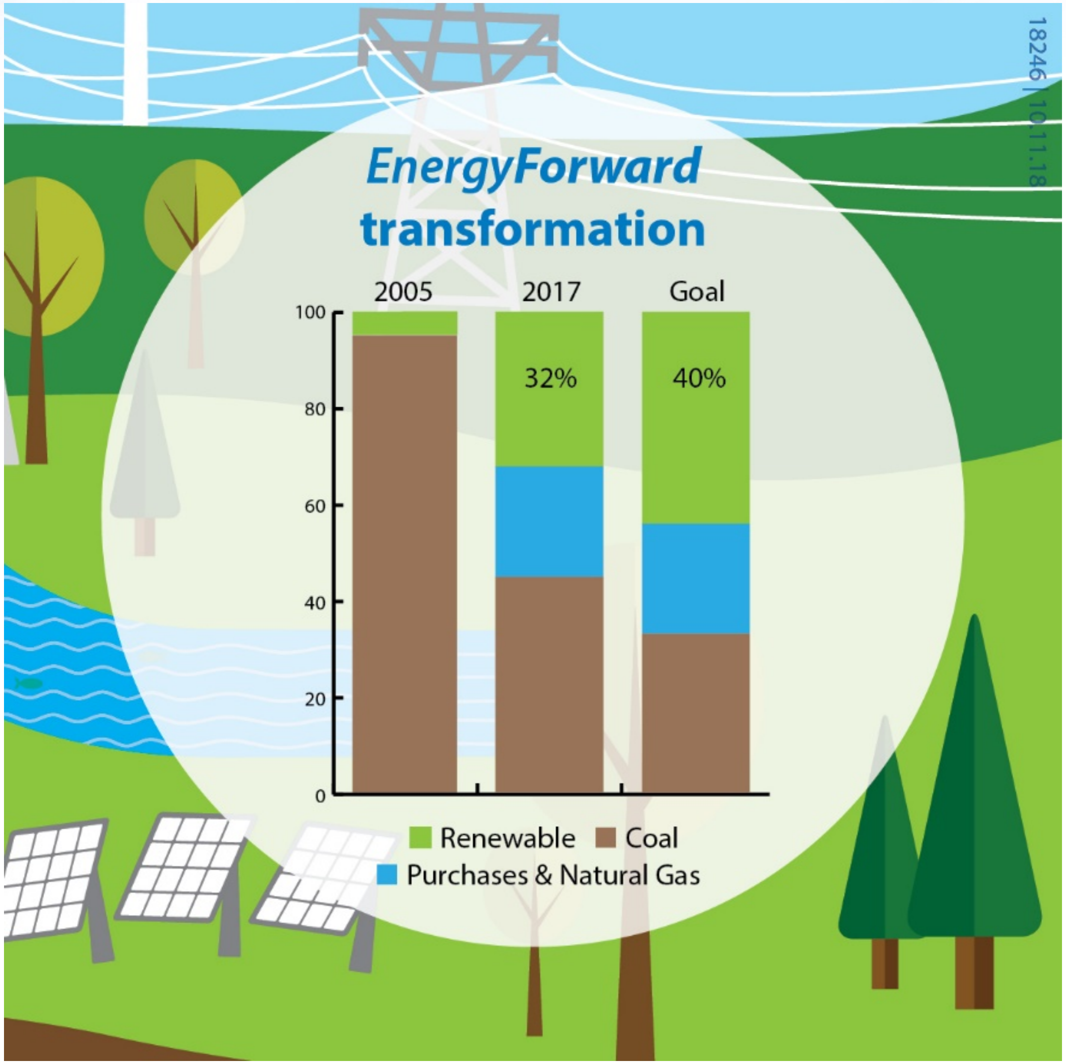
Minnesota Power



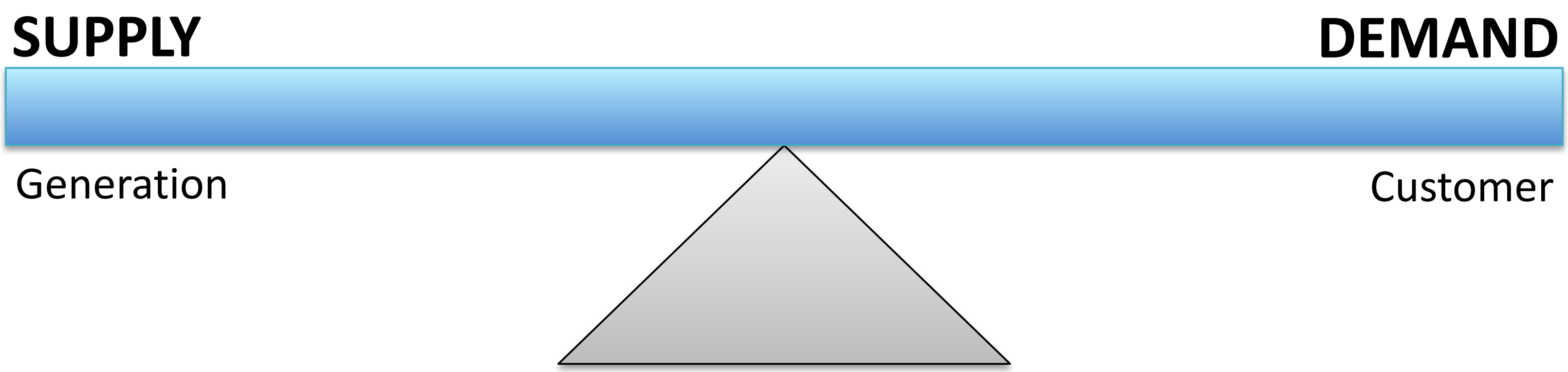
- 26,000 sq. mi. service territory
- 145,000 customers

Current Minnesota Power Programs

Energy Resource Mix



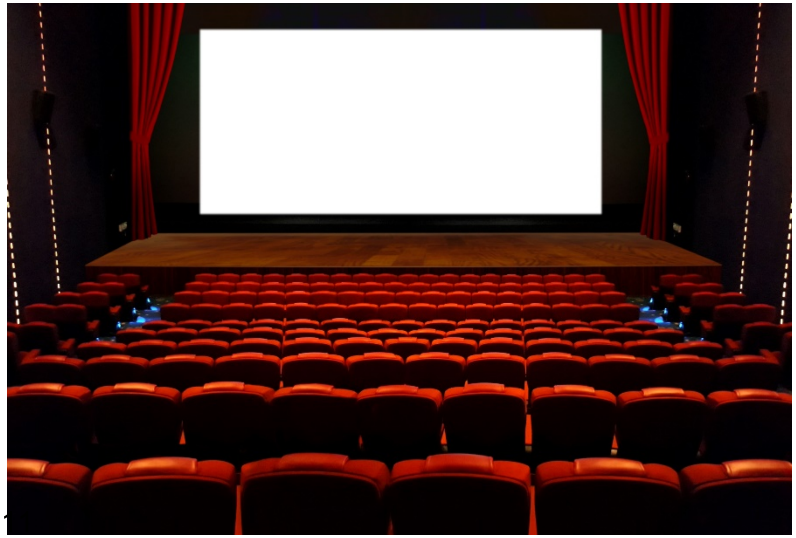
Electricity on the Grid

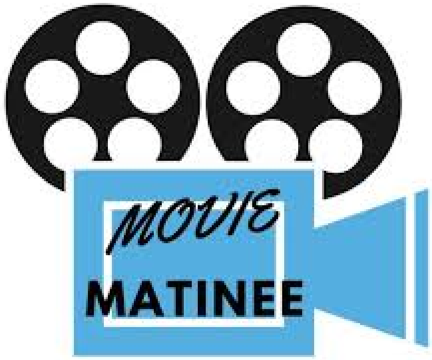


Electricity must be generated exactly when needed to meet customer demand and always be balanced.

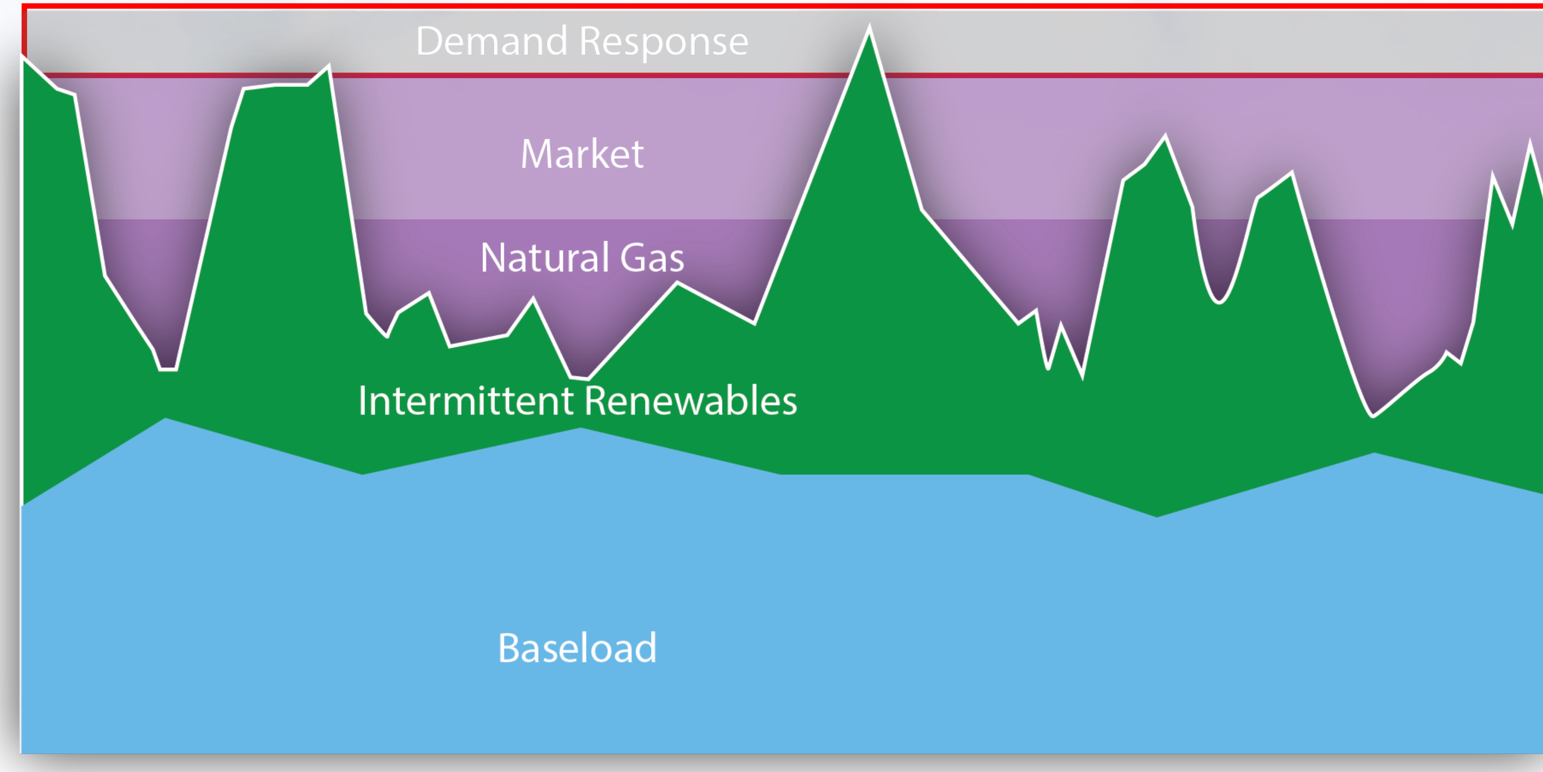
Attachment B

When Supply ≠ Demand





Demand Response: All about Peaks

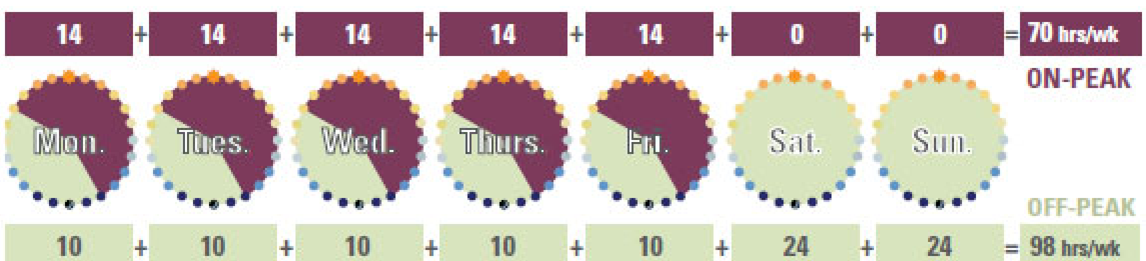


Residential Demand Response Programs:

- Residential Dual Fuel
- Residential Controlled Access
- Conservation Programs
- Time-of-Day Rate (Pilot)
- Off-Peak EV Charging

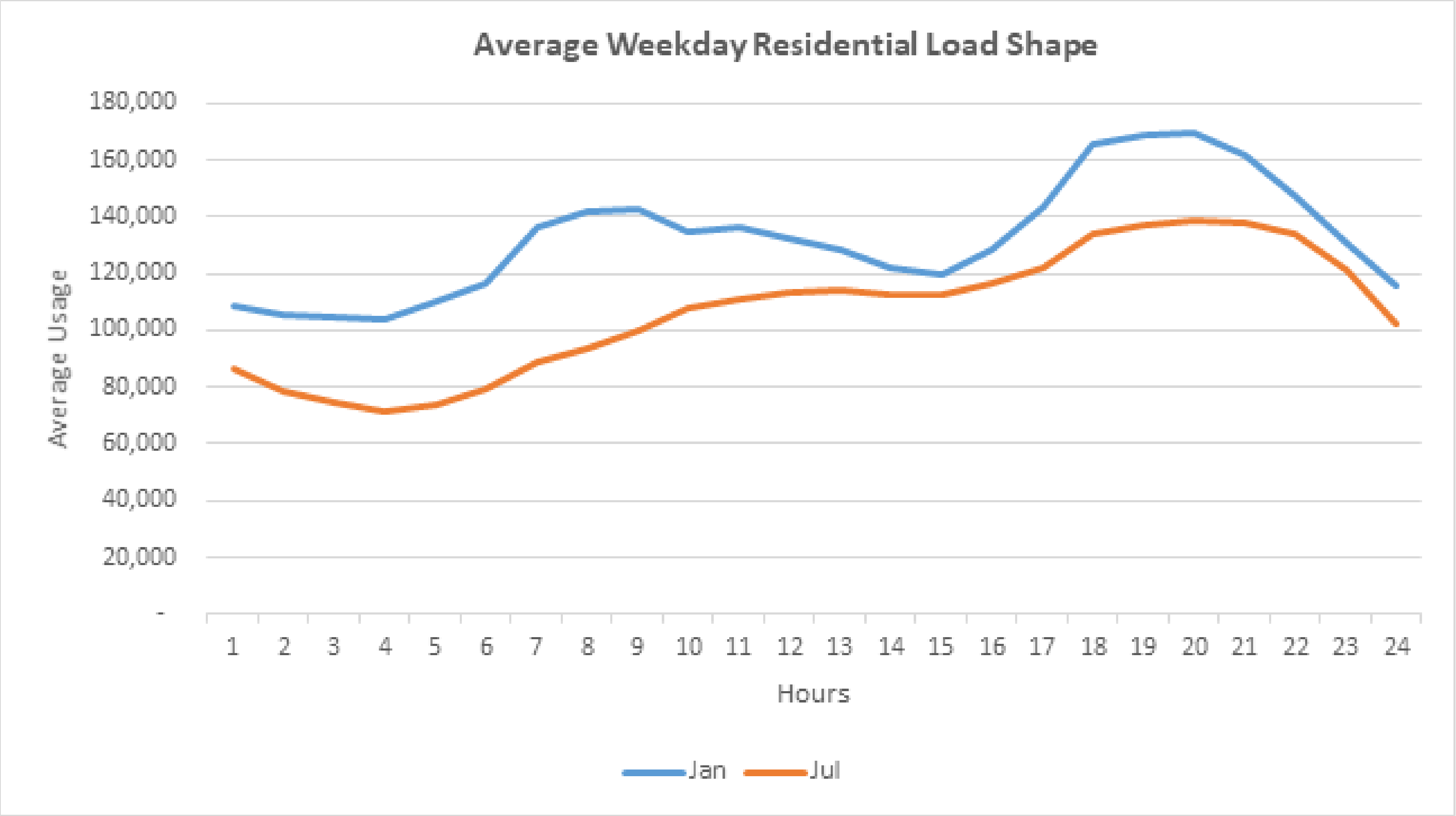
Minnesota Power's Current Time-of-Day Pilot

- Requirement for grant awarded to Minnesota Power from Department of Energy
  - Dual Fuel – Load Control Upgrade
  - Outage Management System and Distribution Automation (OMS & DA) Smart Feeders Project
  - Meter Data Warehouse
  - **Consumer Behavior Study & Critical Peak Pricing Project (TOD)**
- On- & Off-Peak Pricing



- Critical Peak Pricing
- Emergency Event Pricing

Electricity Use Throughout the Day



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Time-of-Use Rates

- Send price signals to customers to
  - Provide an opportunity to save money
  - Reduce energy demand during peak periods
  - Minimize need to purchase energy during high priced hours
  - Maintain reliable energy service to customers
- Typical Program Components

Pricing Periods: High Peak, Peak, Off-Peak, Super Off-Peak	Peak Events: Critical Peak Pricing, Smart Thermostat, Peak-Pricing Rebate	Seasonal Periods: Winter, Summer, Spring and Fall

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Time-of-Day Stakeholder Engagement

- Stakeholder Engagement Meetings
  - Objectives
  - Design principles
  - Goals
  - 4 planned meetings
- Online customer survey
- Customer info-shares
  - Duluth, MN
  - Little Falls, MN
- Potential for new rate proposal and phased approach to Minnesota Public Utilities Commission

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Next Steps

- Interested in hearing more? Sign up for updates by going to www.MNPower.com/TOD

STATE OF MINNESOTA)
) ss
COUNTY OF ST. LOUIS)

AFFIDAVIT OF SERVICE VIA
ELECTRONIC FILING AND U.S. MAIL

Susan Romans of the City of Duluth, County of St. Louis, State of Minnesota, says that on the **20th** day of **February, 2019,** she served Minnesota Power's Report in **Docket No. E015/M-12-233** to the Minnesota Public Utilities Commission and the Energy Resources Division of the Minnesota Department of Commerce via electronic filing. The persons on E-Docket's Official Service List for this Docket were served as requested.

Susan Romans

Susan Romans

Questions?

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