Direct Testimony and Schedules
Lon M. Huber

Before the Minnesota Public Utilities Commission
State of Minnesota

In the Matter of the Application of Northern States Power Company
for Authority to Increase Rates for Electric Service in Minnesota

Docket No. E002/GR-19-564
Exhibit___(LMH-1)

C&I TOU Rate Design & Decoupling

November 1, 2019

Table of Contents

Schedules

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is Lon Huber. I am employed as a Director with Navigant Consulting, Inc.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. My career in the energy industry began in 2007 when I started work at a solar energy research institute housed within the University of Arizona. From 2010 to 2013, I held positions in the solar industry working on matters both local to Arizona and across the U.S. Subsequently, I served as a consultant for Arizona's consumer advocate, the Residential Utility Consumer's Office (RUCO), on energy related issues. I then joined RUCO as a full-time employee. At RUCO, I was the staff lead on significant dockets involving net metering, resource procurement, and pricing. I decided to rejoin the consulting space in 2015 where I have since worked for numerous consumer advocates, state utility commissions, and energy companies. A major topic of my work has been around pricing and rate design with a particular specialty in time-varying rates and subscription-based pricing. I am a regular instructor at the Financial Research Institute (FRI) Transformational Pricing course held at the University of Washington, and I currently consult for entities such as the New York Public Service Commission, and the Office of Consumer Counsel in Connecticut on pricing for renewable energy. My work on rate design, through the above examples and more – including my efforts in Minnesota, New Hampshire, Arizona, and Maine – helped me garner Utility Dive's 2018 Innovator of the Year award.

In terms of educational background, I obtained a Bachelor of Science degree in Public Policy and Management from the University of Arizona in 2009. I also received a Master of Business Administration from the Eller College of Management at the same university. I completed NARUC rate school in 2014. My full resume is included as Exhibit___(LMH-1), Schedule 1.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I am presenting on behalf of Northern States Power Company, doing business as Xcel Energy (Xcel Energy or the Company) a new Time of Use (TOU) rate for the commercial and industrial customers served under the current General Time-of-Day (TOD) tariff. I also present the Company's proposed modification to the current full Revenue Decoupling Mechanism for the residential and small commercial non-demand classes as well as a new decoupling mechanism (RDM-D) for the demand class commercial and industrial customers. Together, these proposals better align our customer rate offerings with system costs, the policy goals of the state, and the utility business model.

II. GENERAL TOU RATE PROPOSAL

A. Key Provisions of New General TOU Rate Proposal

Q. PLEASE DESCRIBE THE NEW GENERAL TOU RATE PROPOSED BY XCEL ENERGY.

A. Xcel Energy is proposing a new three-part TOU rate for Commercial & Industrial (C&I) Demand class customers. The rate has different pricing by season (summer, winter, shoulder) and by time of day (on-peak, mid-peak, off-peak). This new rate removes the Energy Charge Credit provision in the current General TOD tariff and introduces a separate Distribution Demand charge. The proposed tariff language for this new General TOU rate is presented in Exhibit___(LMH-1), Schedule 2.

Q. WHY IS XCEL ENERGY PROPOSING THIS NEW TOU RATE?

A. There are two primary drivers behind the Company's proposal. First, the Company is seeking to test the capabilities of the new Advanced Metering Infrastructure (AMI) meters to provide price signals to encourage its C&I customers to shift energy usage to off-peak periods. This shift in energy usage may allow the Company to rely more heavily on renewable resources as well as avoid the future need for new investments to serve peak loads.

In addition, this new TOU rate is being proposed in compliance with two order points from a July 17, 2019 Commission Order in Docket No. E002/M-18-643.

Q. PLEASE DESCRIBE THE PRIOR COMMISSION ORDER THAT REQUIRED DEVELOPMENT OF A NEW TOU RATE.

A. In October 2018, the Company filed a petition requesting approval of two electric vehicle (EV) pilot programs, a Fleet EV Service Pilot and a Public Charging Pilot in Docket No. E002/M-18-643. As part of its review of these two EV pilots, the Commission also evaluated the Company's current General TOD rate structure that would be available to participants in both EV pilots. Based on this evaluation, Order Point 7 of the Commission's July 17, 2019 Order required the Company to develop and propose a new General TOD rate "that is more reflective of hourly system costs with a price signal designed to reduce peak demand." As discussed in greater detail below, this proposed new General TOU rate will address both of these requirements.

Order Point 5 of the Commission's July 17, 2019 Order also required that within six months that the Company file a commercial EV charging tariff "that is more reflective of hourly system costs with a price signal designed to reduce peak demand." As the proposed General TOU rate will be available to both current General TOD customers and commercial EV customers, this proposed rate is intended to fulfill both Order Points 5 and 7 from the EV pilot program docket.

Q. WHAT CUSTOMERS WILL BE ELIGIBLE FOR THIS NEW TOU RATE?

A. Initially, the rate will be offered on an experimental basis to C&I customers in the commercial EV pilots. The rate will be available on a voluntary basis to all commercial EV customers. We are proposing to limit the number of customers on this rate initially so that we can test and gain insights on the workings of this rate prior to deploying this rate more broadly to our C&I customers.

Q. ARE YOU PROPOSING ANY CHANGES TO THE PEAK CONTROLLED CUSTOMER CLASS?

A. Yes, the existing Peak Controlled tariff would also be modified to use a three-part TOU rate design. Company witness Mr. Steven V. Huso discusses the Peak Controlled tariff in more detail in his Direct Testimony.

Q. WHEN WILL THIS NEW GENERAL TOU RATE TAKE EFFECT?

A. Implementation of this General TOU rate will require the installation of AMI meters. As such, Xcel Energy proposes to implement this new rate once AMI deployment is complete across our Minnesota service territory. As discussed by Company witness Ms. Kelly A. Bloch, deployment of the AMI meters will be substantially complete by the end of 2024. The Company plans to file an implementation plan with additional details regarding the roll-out of this new rate as part of its final rate compliance filing in this case. Mr. Huso discusses the impact of this new rate on the billing system and potential changes required to implement this rate in his testimony.

Q. WHY IS THE IMPLEMENTATION OF THIS GENERAL TOU RATE TIED TO THE INSTALLATION OF AMI METERS?

A. The Company's currently installed AMR meters do not have any register level interval data or multiple "bin" TOU functionality. However, the new AMI meters that are being proposed as part of the AGIS initiative in this case have the interval data capabilities that are needed to implement advanced TOU rates. As discussed by Ms. Bloch, the new AMI meters will enable the recording of customer energy usage in 5 or 15 minute increments throughout the day. This data can be aggregated and collected every four hours by the metering head-end system. This will allow for a much more granular view of the customer load. Customers will also have greater access to their energy usage data thus enabling them to take action to reduce energy usage or shift their energy usage in response to the offered TOU rates.

Q. IF THE NEW AMI METERS WILL NOT BE FULLY ROLLED-OUT UNTIL 2024, WHY IS THE COMPANY PROPOSING THIS NEW RATE NOW?

A. The Company believes that being proactive in this regard will result in a better final rate design. By having the structure for the rate approved in this case, the Company can begin applying data to the structure and analyzing customer impacts to fine tune the rate design prior to the rate becoming effective for all customers.

Q. DESCRIBE THE TOU RATE PERIODS THE COMPANY IS PROPOSING FOR THIS NEW GENERAL TOU RATE.

A. The Company proposes three TOU rate periods: (1) On-peak period from 3 p.m. to 8 p.m. on non-holiday weekdays; (2) Off-peak period from 12 a.m. to 6 a.m. every day; and (3) Mid-peak period for all other hours. The rate also contains a seasonal component with different demand charges for the summer months (June-September), winter months (December-March), and the remaining shoulder months.

Q. HOW DID THE COMPANY SELECT THESE TOU RATE PERIODS?

A. One of the primary objectives of this new rate design is to encourage customers to shift consumption to off-peak periods with the lowest system loads and when there is a surplus of low-cost renewable generation in the wholesale electric market to serve these customers. This abundance of low-cost renewable generation is reflected in a lower Locational Marginal Price (LMP) during these off-peak periods. As shown in Exhibit___(LMH-1), Schedule 3, for most months in the year the peak loads occur between the weekday hours of 3 p.m. and 8 p.m. During those hours, the LMP prices are higher than the average LMP price. Likewise, energy prices are below the average LMP price between the hours of 12 a.m. and 6 a.m. The mid-peak time period reflects the hours in which the average LMP prices occur.

Q. HOW DID THE COMPANY SELECT THE SEASONAL RATE PERIODS?

A. The basis of the seasonal rates is the load data from Xcel Energy's 2025 Integrated Resource Plan (IRP) forecast. Schedule 3 of Exhibit___(LMH-1) shows the net load on the NSP system after incorporating wind and solar generation. Upon analysis of this data, the winter and summer months showed times of higher peak hours than the spring and fall months. The highest system peaks were in the summer, so the summer time period sees the highest demand charges. There was a smaller winter peak, and so that received higher demand charges than the shoulder months. Since the shoulder months were not targeted for load shifting, either seasonally or intra-day, those months do not have the high on-peak energy charge.

Q. HOW DO THE ON-PEAK DEMAND AND MID-PEAK DEMAND CHARGES INTERACT WITH ONE ANOTHER?

A. The two demand charges can be thought of as distinct and different rate components that are determined and billed separately. A customer in a given month is billed the mid-peak demand charge for the highest monthly 15-minute load during the mid and on-peak times (6 a.m. to midnight). Additionally, the customer is billed the on-peak demand charge for the highest monthly 15-minute load during the on-peak time (3 p.m. to 8 p.m.).

Q. HOW DOES THE PROPOSED NEW GENERAL TOU RATE COMPARE TO THE RESIDENTIAL TOU PILOT?[1]

A. The residential pilot rate design and demand rate design proposal are very similar in that they both are based on forward looking data to anticipate grid

[1] Docket No. E002/M-17-775.

needs and both are three period designs to send more accurate price signals to customers. This three-part rate is just a more sophisticated version of the residential pilot rate design due to the fact that demand-rate customers are more sophisticated with energy use, are less homologous as a class, and have greater demands on the system. However, in the end, the same philosophy and analytical approach was used for both rates.

Q. HOW DOES THIS NEW GENERAL TOU RATE PROPOSAL DIFFER FROM THE CURRENT GENERAL TOD RATE FOR C&I DEMAND CUSTOMERS?

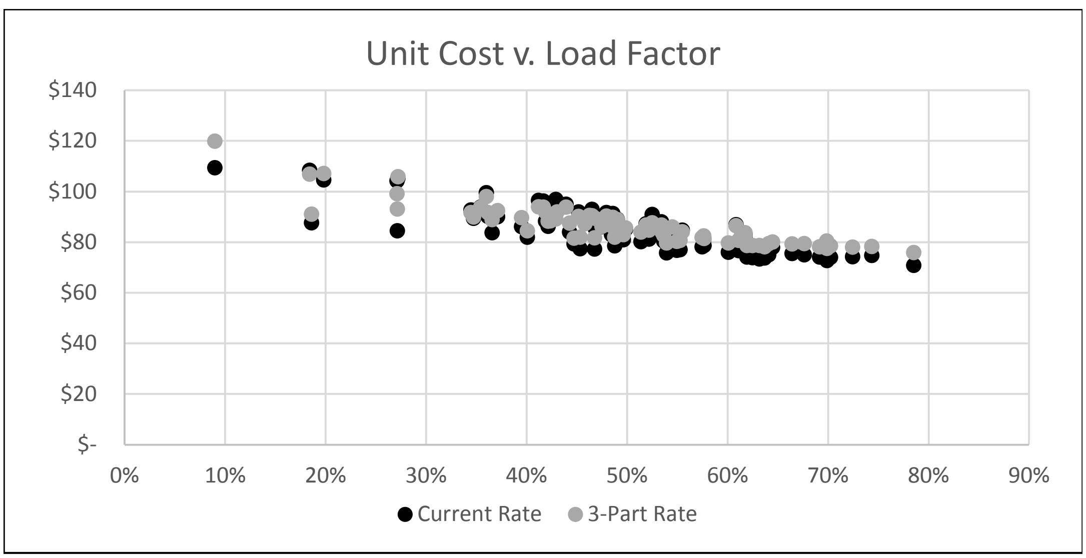
A. Currently, Xcel Energy offers a two-part General TOD rate to C&I customers. This rate is the traditional 12-hour on-peak rate that formed the backbone of the original TOU rates created around 1980. Under the current rate, customers only have one option to avoid peak energy prices. Not only that, but customers who have the desire to avoid those high-price times can only do so if they shift or curtail load for an entire 12-hour period.

The current rate includes an Energy Charge Credit provision that provides an incentive similar to the proposed six-hour off-peak period, by targeting the high load factors that typical occur from energy usage during that time frame. However, this provision is not embedded in the current off-peak rate and does not provide a price signal that is as clear and focused as the proposed TOU rate. The inflexibility of the current two-part rate structure limits how much customers can benefit from time-varying rates and how effective those rates can be toward achieving policy goals such as reducing peak demand.

Q. DOES THE NEW GENERAL TOU RATE REMOVE THE ENERGY CHARGE CREDIT PROVISION OF THE CURRENT GENERAL TOD TARIFF?

A. Yes. The proposed General TOU rate removes the Energy Charge Credit provision for high load factor customers. Under the current General TOD tariff, customers receive an energy credit for energy usage beyond a 55 percent load factor. This reflects the fact that high load factor customers, by virtue of having more even load profiles, have above average usage during the lowest cost time periods. Under the proposed three-part General TOU rate, the additional time period more directly captures the lower costs. On a per-MWh basis, high load factor customers will pay less than low load factor customers. In fact, as shown in Figure 1, the three-part rate has a tighter correlation between unit cost and load factor than the current rate, even without the Energy Charge Credit provision.

Figure 1



Q. WHAT ARE THE OTHER KEY PROVISIONS OF THE PROPOSED GENERAL TOU RATE?

A. The proposed three-part General TOU rate contains a separate Distribution Demand charge for distribution system costs and the same voltage level discounts as the current two-part rate.

Q. DOES THE PROPOSED DISTRIBUTION DEMAND CHARGE FOR THE NEW GENERAL TOU RATE INCLUDE A RATCHET PROVISION?

A. Yes. A ratchet provision refers to billed kW demand that can be affected by peak demands prior to the current billing month. The proposed Distribution Demand charge would be billed based on the highest maximum measured demand in the twelve months ending in the current billing month. Upon the effective date of this rate, the Company would begin the Distribution Demand charge as a zero-month ratchet. In other words, prior monthly demands under the current General TOD tariff would not be used to determine the Distribution Demand billing units.

Q. HOW WOULD THE RATCHET AFFECT CUSTOMERS WITH LARGE MOTORS OR OTHER DEVICES THAT CAUSE HIGH IN-RUSH CURRENTS DURING STARTUP?

A. In the customer meetings discussed in Section B of my testimony, a common concern with ratcheted demand charges had to do with demand spikes during startup. Short periods of high in-rush current would set the Distribution Demand ratchet at a much higher number than the regular maximum measured demand in other hours. As part of this proposal, the TOU tariff would include an isolated high demand waiver for instances where there is a high spike in metered demand due to unexpected outages. Under the waiver, if a customer experienced a demand spike due to unplanned outages on the distribution system, that month would not be used to determine the Distribution Demand billing units. This would protect customers from bill spikes after extreme weather events or other unplanned outages of the distribution system. However, it would not apply to situations where the customer voluntarily shut down and restarted operations.

Q. CAN YOU GIVE AN EXAMPLE OF HOW A CUSTOMER MIGHT BE BILLED FOR DEMAND CHARGES?

A. Let us take two examples to illustrate demand charge billing under the rates in the sample tariff. First, a customer whose monthly peak demand of 1 MW occurs at 4 p.m. on a weekday in January. That customer would see on its bill a line for the on-peak demand charge of $4,850 and a second line for the mid-peak demand charge of $7,500. The distribution demand charge would apply to the highest peak demand in the most recent 12 billing months. If this customer had a peak demand of 1.25 MW in September, then it would see a line for distribution demand charges of $2,500 along with the other charges.

Next, a customer with a monthly peak demand of 1 MW occurring at noon on a weekday in January. For this customer, we need one more piece of information: the monthly peak demand during the on-peak period. Let us say that peak was 800 kW occurring at 5 p.m. on a weekday. This customer would see on its bill a line for the on-peak demand charge of $3,880 and a second line for the mid-peak demand charge of $7,500. Again, if this customer had a peak demand of 1.25 MW in September, then it would see a line for distribution demand charges of $2,500 along with the other charges.

Q. WOULD CUSTOMERS WHO TAKE SERVICE AT EITHER PRIMARY OR TRANSMISSION VOLTAGE PAY THE SAME DISTRIBUTION DEMAND CHARGE?

A. No. This proposal maintains comparable voltage discounts for customers who take service at either primary or transmission voltage. This is a reasonable provision because those customers do not rely on the secondary distribution system for power delivery. Likewise, transmission voltage customers would not pay the Distribution Demand charge at all because they are not connected to the distribution system.

Q. WOULD THE VOLTAGE DISCOUNTS CONTINUE TO APPLY TO THE ENERGY CHARGES AS WELL?

A. Yes. These discounts reflect the fact that taking service at a higher voltage results in fewer line losses to the Company. The demand charge voltage discount would apply only to the Distribution Demand charge.

B. Customer Engagement

Q. DID THE COMPANY SEEK INPUT FROM ITS C&I CUSTOMERS IN DESIGNING THIS RATE?

A. Yes. Xcel Energy held two customer engagement sessions with commercial and industrial customers to discuss the Company's goals and obtain feedback from these customers. Xcel Energy also solicited customer feedback for those that could not attend the meetings in-person.

Q. WHAT FEEDBACK DID YOU RECEIVE FROM THESE C&I CUSTOMERS?

A. Customers were generally supportive of revising the rate to incorporate better price signals. Some of the higher load factor customers expressed concern that they would be unable to shift load to respond to the new rate, and other customers pointed out that shifting load to off-peak times often carries ancillary costs such as overtime, increased maintenance costs, and weekend/night pay. Customers also expressed concern about bill increases when switching to a three-part rate. In order to help them respond to the rate, customers who cannot easily shift load asked for more energy efficiency and demand response programs.

Q. WHAT BEST PRACTICES CAN YOU RECOMMEND FOR MAKING SUCH A FUNDAMENTAL CHANGE TO RATES?

A. In my experience, the Company has already done the first step: involving affected customers outside of a regulatory proceeding. This ensures that customer concerns can be addressed, as much as possible, up front. It is also important for the Company to have an implementation plan and communicate that plan to customers. Having generous lead times prior to the actual switchover will avoid surprise and be more transparent to customers. During the customer meetings, customers also expressed the desire for assistance in identifying their particular load characteristics and the Company intends to develop an implementation plan to address this customer desire. Mr. Huso discusses more details around the implementation plan in his testimony.

C. Policy Goals of New General TOU Rate

Q. WHAT POLICY GOALS DO XCEL ENERGY HOPE TO ACHIEVE THROUGH THIS NEW GENERAL TOU RATE?

A. The primary goal of this new rate design is to better align the rates with the Company's costs to send a more accurate price signal to commercial and industrial customers resulting in lower peak demand. Further, this rate design is designed to encourage customers to shift load to periods of high renewable generation and thus reduce reliance on fossil-fuel generation. At the same time, the new rates are designed to increase customer satisfaction. This is expected to be achieved because the data provided by their AMI meter customers will have more information about their usage so they can respond to the TOU rate signals and make targeted energy efficiency investments to lower their energy costs. This rate design is also consistent with the Commission's direction to optimize the cost-effective integration of EVs by encouraging efficient use of the system to benefit utility ratepayers, including non-EV owners. Finally, the new rate is designed to be revenue neutral to the class, with a tight distribution of individual impacts.

1. *Price Signals to Reduce Peak Demand*

Q. DESCRIBE THE COMPANY'S FIRST POLICY OBJECTIVE TO USE PRICE SIGNALS TO LOWER PEAK DEMAND.

A. TOU rates use price signals to direct customers when to consume or reduce their energy usage to better align with electricity production costs and system needs as compared to traditional flat and tiered rate structures. Time-varying rates give consumers the information and choice to manage their energy use and save money, while beneficially reducing peak demand and thus reducing production costs and carbon emissions over the long-term.

Q. WHAT OTHER INITIATIVES CAN BENEFIT FROM LOWERING PEAK DEMAND?

A. Compared to today's rates, the price signals in the proposed rate design will improve the economics of technologies that can shift load and reduce peak demand. Energy storage is a prime example of such a technology. The low off-peak energy rates are beneficial for charging storage, then the higher on-peak energy rates and peak focused demand charges provide a stronger economic signal than today's rate to discharge the storage during high demand times.

Q. HOW DO NSPM'S ENERGY COSTS VARY WITHIN THE DAY?

A. Exhibit___(LMH-1), Schedule 3 shows the average hourly price of energy according to the Company's 2020-2034 Upper Midwest Integrated Resource Plan (IRP).[2] It shows that locational marginal prices (LMP) at the NSPM load pricing node vary throughout the day, rising in the afternoon and then falling overnight into the morning hours. Prices also vary seasonally, often higher in the summer and winter than in other months.

Q. WHAT ABOUT THE COMPANY'S CAPACITY AND TRANSMISSION COSTS?

A. For NSPM, capacity and transmission costs come from long-term investments in generation and transmission plant. A large portion of the costs are directly related to the peak system loads. Exhibit___(LMH-1), Schedule 3 shows the forecasted system peak load by hour and month in 2025, according to the most recent IRP. The forecasted loads follow the same general shape as the hourly energy prices, both daily and seasonally. Over the long-term, the appropriate price signal will incent customers to modify their load in such a way that helps reduce the peak system load in high-demand hours.

Q. PLEASE DESCRIBE HOW THESE RATES INCENTIVIZE CUSTOMERS TO SHIFT OR REDUCE LOAD DURING PEAK DEMAND TIMES.

A. The three-part rate provides a more targeted price signal than the current rate. The on-peak demand and energy time is only a five-hour window from 3 p.m. to 8 p.m. on weekdays. Unlike the current 12-hour on-peak window, the smaller on-peak window allows for more opportunity to see bill savings by making smaller shifts in behavior. At the proposed rates, if a customer can

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[2] Docket No. E002/RP-19-368.

shift their summer peak in a month by just a few hours, that will result in a bill savings of $6.80/kW. On a broader scale, the three seasonal periods provide a greater incentive to use power during the shoulder months when customers can avoid the on-peak demand charge all-together.

Q. HOW DOES THE PROPOSED GENERAL TOU RATE DESIGN ADDRESS THE GENERATION AND TRANSMISSION COST COMPONENTS?

A. To reflect the intraday changes in energy prices, the proposed rate structure splits the day into three time periods: On-peak, Mid-peak, and Off- peak. As shown in Exhibit___(LMH-1), Schedule 3, for most months in the year the peak loads occur between the weekday hours of 3 p.m. and 8 p.m. During those hours, the LMP prices are higher than the average LMP price. Likewise, energy prices are below the average LMP price between the hours of 12 a.m. and 6 a.m. The Mid-peak time period reflects the hours in which the average LMP prices occur.

A similar approach is used to address long-term capacity costs. The demand charge uses the same time periods as the energy charge, but also contains a seasonal component. Demand charges are highest in the summer months when the system experiences its peak load. The winter months have a demand charge to reflect the bump in load due primarily to heating needs. For the shoulder months, the demand charge is the lowest to incent the maximum amount of load-shifting to these months. While the hourly time periods encourage intraday load shifting, the seasonal component encourages larger shifts in load from summer and winter months to spring and fall months. For example, a C&I customer could move regularly scheduled maintenance to the summer months to take advantage of being down during high demand prices. Seasonal shifting has a bigger effect on capacity and transmission costs by reducing the summer peak loads, thus reducing the capacity obligation incurred by the Company.

Q. DO DISTRIBUTION COSTS VARY IN THE SAME WAY AS PRODUCTION OR TRANSMISSION COSTS?

A. No. Distribution investments are made to provide delivery of a customer's maximum power needs, regardless of when that power is needed. Therefore, the distribution system costs reflect the non-coincident peak demand of each individual customer. In order to properly size the delivery system for each customer or set of customers, the utility must plan for the sum of all customers' maximum loads.

Q. HOW DOES THE PROPOSED RATE DESIGN ACCOUNT FOR DISTRIBUTION COSTS?

A. Since distribution investments are largely based on the non-coincident customer demands, the ratcheted Distribution Demand charge better aligns cost recovery with cost drivers. Under my proposal, customers would pay the Distribution Demand charge based on their maximum measured demand in all hours. The ratchet function smooths out recovery of the fixed distribution assets.

Q. HOW IS THIS METHOD OF RECOVERING DISTRIBUTION COSTS BENEFICIAL FOR CUSTOMERS?

A. This provides a more stable collection of revenue, giving more predictability to customers around their energy costs. Of particular value to businesses with highly seasonal operations is the reduction in the rate for the ratchet. Currently any ratcheted demand is charged the full demand price. Under my proposal, the ratcheted demand would be charged only $2.00 per kW. Instead of collecting all distribution costs in the few months that the business operates, those costs can be collected over an entire year resulting in lower average monthly bills for those customers.

2. Increased Use of Renewable Energy to Meet Customer's Energy Needs

Q. How does your proposed General TOU rate foster increased reliance on renewable energy by the Company?

A. As the Company continues to move toward its renewable energy target, more and more of the generation fleet will be powered by zero marginal cost renewable resources. The 2025 load forecast shows what the forecasted net load on the system will be with increased renewable generators. The times of maximum renewable output are overnight and early morning for wind and in the middle of the day for solar. Seasonally, wind is strongest in the non-summer months, and solar is strongest in the summer months. While these generators complement each other, they unfortunately have limited dispatchability. The price signals contained in this rate design incent customers to use more electricity in times and seasons where renewable energy production is highest. As customers begin to respond to the price signals and take advantage of lower prices, a greater share of the energy consumed will come from renewable and zero-carbon resources. Not only will this have environmental benefits, but the use of these resources will lower the annual fuel cost paid by all customers.

D. Increase Customer Satisfaction

Q. Why does the Company expect that the proposed General TOU rate will result in increased customer satisfaction?

A. Generally speaking, customers like to have optionality when it comes to electric rates and they like to have more control over their energy bills. By offering TOU rates, customers will have additional rate options and will also have more control over their energy bills as they can shift their energy usage to take advantage of off-peak pricing. The high-demand waiver for the ratcheted distribution demand charge, and the increased customer data will also increase customer satisfaction as these components are directly related to feedback the Company received from customers.

E. Optimize EV Integration

Q. HOW DOES THE PROPOSED RATE DESIGN ACHIEVE THE COMPANY'S GOAL TO OPTIMIZE INTEGRATION OF EVS?

A. The proposed TOU rates optimize EV integration by encouraging EV charging during off peak periods and during periods of higher renewable energy production. The more discreet time periods allow for greater flexibility in charging schedules, particularly for commercial customers that operate an electric fleet. The mid-peak time period offers a charging period with lower rates than the current two-part rate. And rather than having to avoid charging during an entire twelve-hour period, the on-peak time in the three-part rate is only five hours.

Q. DOES THE PROPOSED RATE DESIGN ALIGN WITH COMMISSION POLICY?

A. In its February 1, 2019 Order in Docket No. E999/CI-17-879, the Commission made a series of findings following its inquiry into EV charging and infrastructure. Among them, the Commission found that it is the role of utilities to "encourage environmentally and economically optimal EV integration through, at a minimum, the adoption of appropriate and effective time-of-use and EV-specific rate designs, and reasonable initiatives or investments that encourage and support smart charging." It further required utilities to file plans to optimize EV benefits by, for example, aligning charging with periods of lower customer demand and higher renewable energy production and by improving grid management and overall system utilization/efficiency. The Company believes that this proposed rate satisfies these requirements.

F. Customer Rate Impacts and Implementation

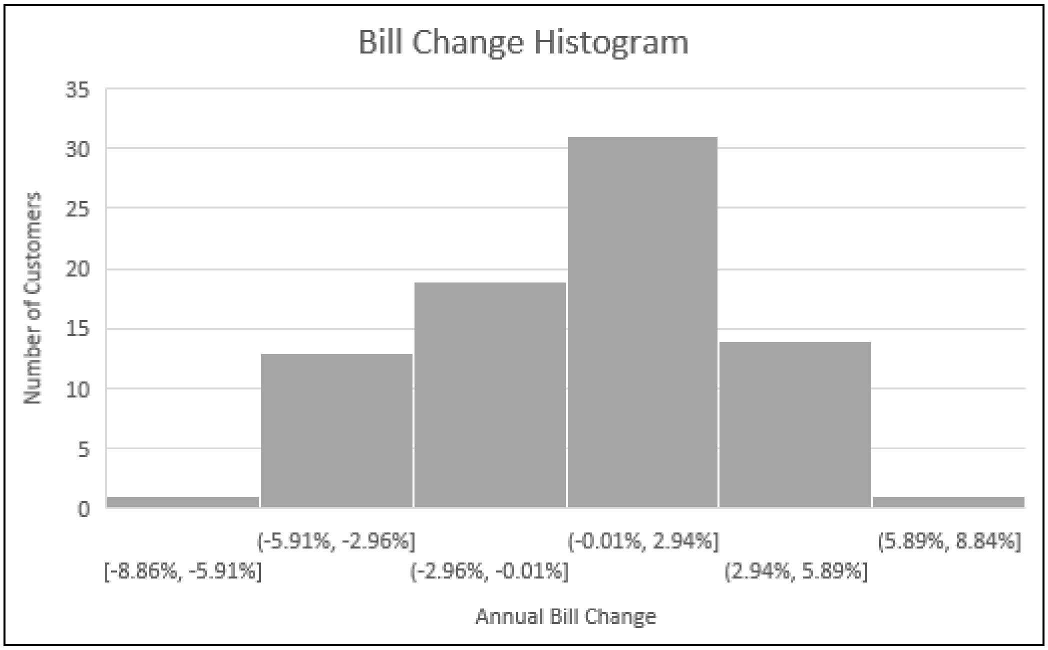
Q. WHAT ANALYSIS HAVE YOU DONE REGARDING THE RATE IMPACT OF THIS NEW GENERAL TOU RATE?

A. I performed a comparison bill analysis on a sample of General TOD customers to determine what the impact would be on switching to the new rate. Compared to the rates proposed by Mr. Huso for the proposed two-part rate in the test year, the proposed three-part rate is designed to be revenue neutral from a class perspective. The complete results are shown in Exhibit___(LMH-1), Schedule 4.

Q. EVEN IF THE RATE IS REVENUE NEUTRAL ON A CLASS BASIS, INDIVIDUAL CUSTOMERS MAY SEE BILL CHANGES AS A RESULT OF THE NEW RATE DEIGN. WHAT DOES YOUR ANALYSIS SAY ABOUT INDIVIDUAL CUSTOMER IMPACTS?

A. The comparison bill analysis I performed on the customer sample group shows an even distribution of individual bill impacts upon switching to the three-part rate. It is important to note that these results are just for switching rates, not modifying load in any way after switching. The bill impacts range from an 8.9 percent decrease to an 8.2 percent increase. A histogram of the individual bill impacts of the proposed future TOU design compared to the existing rate design under rates proposed in this case is shown as Figure 2 below.

Figure 2



Q. FOR CUSTOMERS WHO WOULD SEE A BILL INCREASE AS A RESULT OF SWITCHING TO THE NEW RATE, IS THE COMPANY PROPOSING TO OFFER ANY SORT OF BILL PROTECTION ONCE THE RATE DESIGN IS AVAILABLE AT SCALE?

A. Yes. Some customers by virtue of their current load profile may see a bill increase on the three-part rate. For those customers, the Company proposes a bill protection adjustment. The residential TOU pilot provides a conceptual example for this adjustment. The details will be proposed by the Company as part of its implementation plan for the three-part rate. The cost of any bill protection mechanism would be captured in the RDM-D mechanism.

Q. WILL THE COMPANY ASSIST CUSTOMERS IN EVALUATING THE THREE-PART RATE IN ADVANCE OF THE RATE GOING INTO EFFECT?

A. Yes. The Company will commit to develop a tool to assist customers in understanding the impacts of the three-part rate to bills. This will allow customers to take action and prepare prior to actually seeing the price signal. The Company's implementation plan will describe the features of the tool in greater detail.

Q. FOR CUSTOMERS WITH LIMITED ABILITY TO SHIFT LOAD, HOW CAN THEY RESPOND TO THE PRICE SIGNAL?

A. Certain customers may not be able to shift load easily. This could be due to facing increased overtime or night and weekend costs, inflexible operating hours like retail stores, or the business is already operating at close to full capacity. These customers could respond to price signals by temporarily or permanently reducing loads through demand management or energy efficiency, rather than shifting.

Q. WHAT DOES THE COMPANY PROPOSE TO DO FOR THESE CUSTOMERS?

A. As shown in the most recent IRP, the Company has proposed to increase their energy efficiency commitment. Energy efficiency, demand response, and program support are all ways that the Company can help customers with limited load flexibility reduce their demands during the peak hours.

Q. IN GENERAL, HOW WILL CUSTOMERS WHO DO NOT RESPOND TO THE PRICE SIGNAL BENEFIT FROM THIS RATE?

A. As discussed above, any response from customers will help control costs and mitigate future investment needs, particularly on the generation side. The benefits of having some customers respond to the price signal will be felt by all customers, even those not directly in the General TOD class.

Q. WOULD THE SMART CHARGERS USED FOR THE FLEET EV SERVICE PILOT PROGRAM INTEGRATE WITH THE THREE-PART RATE?

A. In the docket authorizing the Fleet EV Service pilot, the Commission required that all chargers used for this pilot have smart charging capability. Smart chargers that send data back to the Company can be programmed with the three-part rate time periods to maximize efficient and cost-effective charging. Also, the demand rate component allows for customers to save more money by having the smart charger manage the load in such a way as to maximize load factor. As shown above, the three-part rate combined with high load factor usage results in the lowest per-unit cost of energy.

III. DECOUPLING AND REVENUE DECOUPLING MECHANISM-DEMAND (RDM-D)

Q. WHAT IS DECOUPLING?

A. Decoupling is a rate adjustment mechanism that trues up the revenues received by a utility to the authorized test year revenue requirement set by a commission in a rate case. For utilities with multi-year rate plans, decoupling is essential to maintaining fixed cost recovery in the interim years between rate cases. In general, decoupling is used as a mechanism to better align the utility’s interests with public policy goals, thus making it easier to achieve those goals.

Q. WHAT ARE PUBLIC POLICY REASONS SUPPORTING DECOUPLING?

A. Public utilities are just like any other business in that, when sales increase, so do potential revenues. This may create an incentive to maximize sales. By weakening the link between raw sales and utility earnings, utilities have more flexibility to offer aggressive energy efficiency programs, innovative rate designs such as the proposed three-part TOU demand rate, and optional programs to meet customer demands. Decoupling also helps ensure that utilities continue to collect their authorized revenue to safely and reliably serve customer load, even as that load responds to economic trends outside the utility's control. Paired with public policy programs, decoupling maximizes the effectiveness of those programs. Also, as utilities are increasingly agents of transformative policies, decoupling removes some of the financial uncertainty faced by utilities between rate cases.

Q. PLEASE ELABORATE ON HOW DECOUPLING CAN FURTHER POLICY GOALS, SPECIFICALLY WITH REGARD TO THE EXAMPLES YOU LIST ABOVE.

A. The Company fully recognizes that conservation and increased renewable energy production are beneficial to the public at large. The Company also wishes to provide services to customers that reflect their needs and priorities. It is for these reasons that the Company is making the proposals in this docket and the current IRP. But in the short term, these programs will result in lower revenues as customers use less power and take the power they do use in times when the rates are lower. And since the Company's fixed costs do not change during the test year until the next rate case, decoupling mechanisms ensure that the Company remains whole while offering these programs.

Q. PLEASE EXPLAIN THE CURRENT DECOUPLING MECHANISM FOR THE RESIDENTIAL AND SMALL COMMERCIAL NON-DEMAND CLASSES.

A. The Commission approved a three-year decoupling pilot via their May 8, 2015 Findings of Fact, Conclusions, and Order in Docket No. E002/GR-13-868. In the Company's next rate case, the Commission extended the decoupling pilot through 2019 via their June 12, 2017 Findings of Fact, Conclusions, and Order in Docket No. E002/GR-15-826. This was done in order to match the Company's multi-year rate plan. The current decoupling mechanism expires with the test year.

Q. WHAT IS THE COMPANY PROPOSING IN THIS CASE FOR THE RESIDENTIAL AND SMALL COMMERCIAL NON-DEMAND CLASS CUSTOMERS?

A. The Company is proposing the full decoupling mechanism that was approved in the previous two cases. The Company's proposed tariff is attached as Exhibit___(LMH-1), Schedule 5. The Company looks to build on the success of the current decoupling mechanism, and therefore proposes to maintain decoupling with some changes. The mechanism measures sales revenues against a baseline revenue-per-customer by class, with over- or under-recoveries calculated and deferred each month. The annual result is credited or charged to customers through a $ per kWh factor applied to each individual customer's usage each month for twelve months as a separate line item on their bill. The Company proposes to begin the deferral calculation January 1, 2021, with annual reporting of results by February 1 after the conclusion of each year and the corresponding factors in place April through March. For example, if the mechanism begins January 1, 2021, then deferrals would be calculated for each month of 2021. The Company would file an annual report by February 1, 2022, and the credit or surcharge factors would be effective

April 1, 2022 through March 31, 2023. The Company proposes this to be a permanent mechanism.

Q. PLEASE DESCRIBE THE DECOUPLING DEFERRAL CALCULATIONS DURING THE INTERIM RATE PERIOD.

A. The Company will begin calculating monthly decoupling deferrals in January 2021, at the same time interim rates are in effect. Monthly baseline fixed revenue per customer and baseline fixed energy charges will be calculated using 2021 test year sales and rates, including interim rates, in effect during each month of the deferral. On a monthly basis throughout the interim rate period, authorized revenues are calculated using the baseline fixed revenue per customer and actual monthly customer accounts. Actual revenues are calculated using the baseline fixed revenue per customer and actual monthly sales. The Decoupling deferral is equal to the over- or under-recovery between authorized and actual revenue each month.

Q. PLEASE DESCRIBE THE DECOUPLING DEFERRAL CALCULATIONS AT THE CONCLUSION OF THE CASE.

A. Monthly baseline fixed revenue per customer and baseline fixed energy charges will be calculated each month based on the test year or plan year in effect at that time. For 2021, the RDM calculation would measure the difference between the 2021 plan year authorized revenues and the 2021 actual revenues as calculated in the mechanism. For 2022, the RDM calculation would measure the difference between the 2022 plan year authorized revenues and the 2022 actual revenues as calculated in the mechanism. For years beyond 2022, the RDM calculation would measure the difference between the

2022 plan year authorized revenues and that year's actual revenues as calculated in the mechanism.

Q. WHAT CHANGES TO DECOUPLING ARE YOU PROPOSING IN THIS CASE?

A. The Company is proposing several updates to decoupling in this case:

- Additional Rate Codes Included: The Company proposes to add the Small General Service Direct Current (A13) and Small Municipal Pumping Service (A40) to the Small Commercial Non-Demand Class within the Decoupling Mechanism. These customers are similar to the other classes in the Small Commercial Non-Demand class. For instance, the Small General Service Direct Current (A13) customers are subjected to the same rates as the other Small General Service customers (Rate Codes A09, A10, and A11). The Small Municipal Pumping Service customers are not subjected to demand charges. Further, we are adding our residential time-of-use pilot customers to the Decoupling Mechanism since this pilot was not in existence when our last mechanism was approved by the Commission. The bill protections associated with the residential time-of-use pilot will also be added to the Decoupling Mechanism and collected from all customers subject to this mechanism.
- Cap: The Company proposes to increase the cap on surcharges to five percent of base revenues by class, compared to the current cap of three percent. This is meant to reflect a proposed increase in energy efficiency and demand response in the current IRP.
- Demand Customers: Instead of the sales true-up currently in place for the demand customers, the Company proposes changing to a full

decoupling mechanism using a RDM-D model. The Company's proposed tariff is attached as Exhibit___(LMH-1), Schedule 6.

- Duration: The Company proposes to make the decoupling mechanisms permanent in this case. The Company and its customers have enough experience with decoupling to be comfortable with the program. Also, for reasons more fully discussed below, the Company expects to see accelerated transition in the utility's relationship with customers in order to meet public policy goals; decoupling provides a smoother glidepath for the Company to implement those policy goals.

Q. WHY IS THE COMPANY PROPOSING THESE CHANGES?

A. There are two reasons for proposing these changes at this time. First, as discussed in the ongoing resource planning docket, NSPM is proposing to increase the targeted energy efficiency and demand response savings goals. Second, as directed in Docket No. E002/M-19-127, the Company evaluated what modifications would better reflect the value of electric vehicles and other beneficial electrification.

Q. HOW WOULD THE PROPOSED CHANGES RELATE TO ELECTRIC VEHICLES AND OTHER BENEFICIAL ELECTRIFICATION?

A. It is important to note that the electric vehicle pilots offered by the Company are outside the decoupling mechanism. That being said, the Company recognizes that not all electric vehicles are covered by the electric vehicle-specific tariffs. As customers, both residential and non-residential, add electric vehicles to the system, those that are charged under the host's retail tariff will add sales in future years. The same principle applies to beneficial electrification; those actions are anticipated to increase sales under the base tariffs.

Q. PLEASE EXPLAIN THE CURRENT SALES TRUE-UP FOR THE DEMAND CUSTOMER CLASSES.

A. Customers in the demand classes are currently in a partial decoupling mechanism known as the sales true-up. In the Commission's order dated June 12, 2017 for Docket No. E002/GR-15-826, the Commission approved using the sales true-up for these commercial and industrial customers. The sales true-up is based on weather-normalized sales in a given year, with a cap on surcharges of three percent of base (non-fuel) revenues.

Q. PLEASE EXPLAIN HOW THE RDM-D WILL WORK FOR DEMAND CUSTOMERS.

A. The base revenues are the authorized revenues for the affected customer classes in the test year. In each subsequent year to the test year monthly deferrals are calculated as the difference between actual revenues and authorized base revenues. The annual deferral is either credited or charged to customers over a 12-month period through a $ per kWh factor applied to customer usage. The RDM-D would directly incorporate the revenues from demand charges to more equally share the costs and benefits associated with changes in class load factor. The RDM-D would also incorporate uncollected revenues due to the transition protection adjustment as part of the three-part rate. The revenues refunded to these customers will be added to the RDM-D and collected from all customers subject to that rate.

Q. WHY ARE YOU PROPOSING TO INCLUDE THE IMPACTS OF WEATHER IN THE RDM-D?

A. The Company proposes to include the impacts of weather in the RDM-D in order to be consistent with the RDM mechanism. Under the current decoupling mechanism, some sales in the sales true-up for demand customers are weather normalized, which has the effect of muting the impact of the increased sales due to electric vehicle charging and electrification. The demand class customers are generally less weather-sensitive than the Residential and Small Commercial classes included in the RDM.

Q. WHY IS THE COMPANY PROPOSING TO IMPLEMENT THE RDM-D INSTEAD OF THE CURRENT SALES TRUE-UP DECOUPLING MECHANISM?

A. Under the current sales true-up, only the energy sales are directly evaluated for calculating the revenues in a given year, and demand revenues are derived from the energy sales. A sales true-up approach is appropriate for energy only rate classes but does not accurately account for demand classes because a large portion of fixed-cost revenue for these customers comes from demand charges. The RDM-D mechanism represents a more accurate means by which the Company can remain whole while at the same time fulfilling public policy goals regarding demand response, energy efficiency, and renewable generation.

Q. HOW WILL THE CREDIT OR SURCHARGE BE APPLIED TO CUSTOMER BILLS?

A. Adjustments due to the RDM and RDM-D mechanisms will be applied to customer usage as a $ per kWh factor and shown as a separate line item on customer bills, just as they are currently in the RDM and sales true-up mechanisms.

Q. IN ADDITION TO THE ELECTRIC VEHICLE CUSTOMERS, HAVE ANY CLASSES BEEN OMITTED FROM THE DECOUPLING AND RDM-D MECHANISMS?

A. Yes. The Company has elected to omit the lighting class and interdepartmental sales from both mechanisms. Lighting customers have been excluded since they are for the most part on per-fixture rates; therefore, their bills are flat. The interdepartmental customers have also been excluded since they make up a minimal amount of total sales.

Q. ARE THERE ANY OTHER DIFFERENCES BETWEEN THE CURRENT DECOUPLING MECHANISMS AND THE PROPOSED MECHANISMS?

A. Yes. The proposed RDM and RDM-D mechanisms would have a cap on surcharges of five percent of base revenues by class, compared to the current cap of three percent. As discussed previously, this is meant to reflect a significant increase in energy efficiency and demand response in the current IRP. Further, the Company was required to increase their demand response offerings by 400 MW with the new IRP.

Q. IN THE PREVIOUS SECTION YOU DISCUSSED HOW CUSTOMERS CAN REDUCE THEIR BILLS BY SHIFTING OR REDUCING LOAD. DOES THE PROPOSED RDM-D ALLOW CUSTOMERS TO RECEIVE THE BENEFITS OF SHORT TERM COST SAVINGS?

A. Yes, because like all decoupling mechanisms the RDM-D is intended to protect the long-term fixed cost recovery of the utility between rate cases. If customers respond to the price signal and help reduce the system's peak load, that will result in savings that will be passed to customers in the near-term. First, if customers respond to the price signal by reducing their usage, they will enjoy fuel-related savings immediately. Second, as customers shift load to lower-cost time periods, the utility does not have to generate power or purchase power during times of high LMPs, which results in a reduction in the overall system fuel costs.

Q. DOES THE RDM-D ALLOW CUSTOMERS TO AVOID LONG-TERM COSTS AFTER RESPONDING TO THE PRICE SIGNALS IN THE THREE-PART RATE?

A. Yes. Over the long term, a consistent reduction in system load reduces the capacity obligation incurred by the Company. This affects customers directly in two ways. First, it increases the amount of capacity that the Company can sell to other utilities. Such sales shift costs in the jurisdictional cost-of-service study from retail customers to wholesale operations. Second, if the load share of NSPM in the total NSP system decreases, NSPM will see lower costs through the Interchange Agreement. Both of these effects of increased available system capacity would put downward pressure on retail rates for all customers in future rate cases. The RDM-D allows the Company to remain whole between rate cases, especially during multi-year rate plans.

Q. HOW DOES THE RDM-D COMPARE TO HOW OTHER UTILITIES TREAT REVENUE DECOUPLING FOR COMMERCIAL AND INDUSTRIAL CUSTOMERS?

A. Revenue decoupling has spread across the country over the last decade. While many utilities do not include large commercial and industrial customers in their decoupling mechanisms, the ones that do take a varied approach. Other states such as New York and Connecticut currently have decoupling mechanisms for large commercial and industrial customers like the one proposed here. The specific mechanism approved by a given state's commission or legislature reflects the particular environment of those states. Given that there is no consensus around "best practices" for decoupling with large commercial and industrial customers, a reasonable program is one that addresses fixed cost recovery in a manner that shares the risks between the utility and its customers. The proposed modifications reflect such a reasonable program for the reasons described above.

IV. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. With regard to the proposed three-part General TOU rate, it is a rate design that more closely mirrors the hourly and seasonal cost differential, thereby sending more accurate price signals to customers. If customers are successful in responding to the price signals, it offers the opportunity for customers to save on their bills and for the utility to reduce its costs.

The proposed changes to the current partial decoupling mechanism in use by demand customers will keep the Company indifferent to advances in energy efficiency and demand response programs. Given the proposed increase to those programs as described in the Company's ongoing resource planning docket, this full decoupling mechanism will allow the Company to achieve its goals in a more equitable manner. The full decoupling mechanism will also more fully reflect changes in sales due to electric vehicle charging under base tariffs and beneficial electrification more generally.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

NAVIGANT

Lon.huber@navigant.com
New York, NY
Direct: 928.380.5540

Professional Summary

Lon Huber leads Navigant's North American retail regulatory offering. In this capacity, Lon provides expert witness testimony, proceeding strategy, and pricing solutions on behalf of clients across the energy sector. Lon has received numerous awards including being named Utility Dive's Innovator of the Year for 2018 and is well known for his creative data-driven solutions to some of the energy industry's most pressing issues.

Specifically, Lon pushes advances in rate design, DER pricing reform, RPS modernization, and energy storage. He is frequently cited in trade press and speaks regularly at conferences across the country. With over 10 years in the energy industry, his experience spans public and private sectors, as well as academia. Lon has a rich history with rate design work, through former companies, state consumer advocate offices, and current Navigant clients. Lon has directly educated consumers on new rates and demand response options, designed tariffs, and consulted on education and communication strategy. Finally, Lon instructs at FRI's Advanced Transformational Rates Seminar at the University of Washington.

Areas of Expertise

- Rate Design
- DER Compensation Reform
- Grid and RPS Modernization
- Energy storage
- Energy Product Development
- Stakeholder facilitation

Work History

- Vice President, Strategen Consulting
- Special Projects Advisor to the Director, Arizona's Residential Utility Consumer Office (RUCO)
- Vice President, Arbsource
- Manager, Suntech

Publications

- Primer: Subscription Pricing for Regulated and Competitive Energy Providers
- 2017 REN21 Global Status Report – Author of the energy storage chapter.
- NYC's Aging Power Plants: Risks, Replacement Options, and the Role of Energy Storage
- RPS 2.0 – A Clean Peak Standard for a smarter energy future

Education

- Instructor – FRI's advanced rate design course at the University of Washington
- NARUC Rate Design School
- Master of Business Administration, Eller College of Management
- BS, Public Policy and Management, University of Arizona

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2017-2019 Sample of Speaking Engagements

- Solar Power International – Distributed storage best practices
- ARPA-E and ESA National Conference – Energy Storage and Decarbonization
- Winter NARUC and APPA Webinar – Cutting Edge Rate Design
- EUCI – Residential Demand Charges and NY Policy Update
- NARUC Orlando – Microgrids, Energy Storage Multi-Use Applications, and Rate Design
- Critical Consumer Issues Forum – New Customer Driven Solutions and Grid Modernization
- Solar Power International – Energy Storage Policy and Market Forecast
- SEPA Grid Evolution Summit – DER Rate Design and SEPA Utility Conference Salon Moderator
- National Association of Regulatory Utility Commissioners – Moderator, Evolving Grid Innovations
- National Association of State Utility Consumer Advocates – Designing Rates for DG
- US Department of Energy National Community Solar Partnership – Community Solar Webinar
- Annual conference of the Coalition for Community Solar Access – Community Solar Program Best Practices

Awards

- Innovator of the Year 2018 – Utility Dive
- Top Innovator Honor Roll and Fortnightly under Forty - Public Utilities Fortnightly
- The Phil Symons Award - Energy Storage Association
- 40 under 40 – Arizona Daily Star
- Young Alumni Award and Outstanding Professional Staff Member – University of Arizona
- Congressional Recognition Award – US House

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AVAILABILITY
Available beginning January 1, 2024 for general service to any non-residential customer with a minimum peak demand of 25 kW and Advanced Metering Infrastructure (AMI) metering.

Available prior to January 1, 2024, service on an experimental basis to a maximum of 100 electric vehicle charging applications without AMI metering subject to the availability of alternative metering capability and Company approval.

DETERMINATION OF CUSTOMER BILLS
Customer bills shall reflect energy charges (if applicable) based on customer's kWh usage, plus a customer charge (if applicable), plus demand charges (if applicable) based on customer's kW billing demand as defined below. Bills may be subject to a minimum charge based on the monthly customer charge and / or certain monthly or annual demand charges. Bills also include applicable riders, adjustments, surcharges, voltage discounts, and energy credits. Details regarding the specific charges applicable to this service are listed below.

RATE

Customer Charge per Month	$31.00		
	Jun-Sep	Dec-Mar	Other Months
System Demand Charge per Month per kW			
On-Peak Period Demand	$6.80	$4.85	$0.00
Mid-Peak Period Demand	$9.75	$7.50	$7.50
Distribution Demand Charge per Month per kW			
Secondary Voltage	$2.00		
Primary Voltage	$1.52		
Transmission Transformed Voltage	$0.64		
Energy Charge per kWh			
On-Peak Period Energy	$0.05367		
Mid-Peak Period Energy	$0.03258		
Off-Peak Period Energy	$0.00970		
Energy Voltage Discount per kWh			
Primary Voltage	$0.00115		
Transmission Transformed Voltage	$0.00282		
Transmission Voltage	$0.00293		

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(Continued on sheet No. 5-34)

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In addition, customer bills under this rate are subject to the following adjustments and/or charges. N

FUEL CLAUSE
Bills are subject to the adjustments provided for in the Fuel Clause Rider.

RESOURCE ADJUSTMENT
Bills are subject to the adjustments provided for in the Conservation Improvement Program Adjustment Rider, the State Energy Policy Rate Rider, the Renewable Development Fund Rider, the Transmission Cost Recovery Rider, the Renewable Energy Standard Rider and the Mercury Cost Recovery Rider.

ENVIRONMENTAL IMPROVEMENT RIDER
Bills are subject to the adjustments provided for in the Environmental Improvement Rider.

SURCHARGE
In certain communities, bills are subject to surcharges provided for in a Surcharge Rider.

LOW INCOME ENERGY DISCOUNT RIDER
Bills are subject to the adjustment provided for in the Low Income Energy Discount Rider.

The following are terms and conditions for service under this tariff.

LATE PAYMENT CHARGE
Any unpaid balance over $10.00 is subject to a 1.5% late payment charge or $1.00, whichever is greater, after the date due. The charge may be assessed as provided for in the General Rules and Regulations, Section 3.5.

DEFINITION OF TIME OF USE PERIODS
The On-Peak period is defined as those hours between 3:00 p.m. and 8:00 p.m. Monday through Friday, except the following holidays: New Year's Day, Good Friday, Memorial Day, Independence Day, Labor Day, Thanksgiving Day, and Christmas Day. When a designated holiday occurs on Saturday, the preceding Friday will be designated a holiday. When a designated holiday occurs on Sunday, the following Monday will be designated a holiday.

The Mid-Peak period is defined as all hours not defined as On-Peak or Off-Peak periods.

The Off-Peak period is defined as those hours between midnight (12:00 a.m.) and 6:00 a.m. every day. N

(Continued on Sheet No. 5-35)

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DETERMINATION OF ON PEAK PERIOD DEMAND
The actual on peak period demand in kW shall be the greatest 15-minute load for the on peak period during the month for which the bill is rendered. The adjusted demand in kW for billing purposes shall be determined by dividing the actual on peak demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW. In no month shall the on peak billing demand be greater than the value in kW determined by dividing the kWh sales for the billing month by 100 hours per month. The greatest monthly adjusted on peak period demand in kW during the preceding 11 months shall not include the additional demand which may result from customer's use of standby capacity contracted for under the Standby Service Rider.

DETERMINATION OF MID PEAK PERIOD DEMAND
The actual mid peak period demand in kilowatts shall be the greatest 15-minute load for the combined mid peak and on peak periods during the month for which the bill is rendered rounded to the nearest whole kW. The adjusted demand in kW for billing purposes shall be determined by dividing the actual mid peak demand by the power factor expressed in percent but not more than 90%, multiplying the quotient so obtained by 90%, and rounding to the nearest whole kW. In no month shall the on peak billing demand be greater than the value in kW determined by dividing the kWh sales for the billing month by 100 hours per month. The greatest monthly adjusted mid peak period demand in kW during the preceding 11 months shall not include the additional demand which may result from customer's use of standby capacity contracted for under the Standby Service Rider.

DETERMINATION OF DISTRIBUTION DEMAND
The distribution demand will be the greatest 15-minute load, regardless of time of use period and not adjusted for power factor, which occurred during the past 12 months, including the current month. Unusual demands incurred after a failure on the Company's distribution system will not be included in the evaluation of distribution demand billing in kilowatts, at the Company's discretion.

POWER FACTOR
For three phase customers with services above 200 amperes, or above 480 volts, the power factor for the month shall be determined by permanently installed metering equipment. For all single phase customers and three phase customers with services 200 amperes or less, a power factor of 90% will be assumed. N

(Continued on Sheet No. 5-36)

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BILL PROTECTION
Billing charges considered for bill protection will include demand and energy charges. Bill protection will be considered only for customers beginning service on this tariff January 1, 2024 or later, based on the first 12 months of service on this tariff. Any Pilot program billing charge in excess of 5 percent of the corresponding billing charge that would have been applied had the customer been billed with the General Time of Use Service tariff will be credited to the customer’s account, including any applicable taxes. The bill protection in this paragraph will terminate after the first 12 months of service with this tariff.

COMPETITIVE SERVICE
Competitive Service is available under this schedule subject to the provisions contained in the Competitive Response Rider.

STANDBY SERVICE
Standby Service is available under this schedule subject to the provisions contained in the Standby Service Rider.

MINIMUM DEMAND TO BE BILLED
The monthly minimum on peak and mid peak period billing demands shall not be less than provided above.

TERMS AND CONDITIONS OF SERVICE
1. Alternating current service is provided at the following nominal voltages:
   a. Secondary Voltage: Single or three phase from 208 volts up to but not including 2,400 volts,
   b. Primary Voltage: Three phase from 2,400 volts up to but not including 69,000 volts,
   c. Transmission Transformed Voltage: Three phase from 2,400 volts up to but not including 69,000 volts, where service is provided at the Company's disconnecting means of a distribution substation transformer, or
   d. Transmission Voltage: Three phase at 69,000 volts or higher.

   Service voltage available in any given case is dependent upon voltage and capacity of Company lines in vicinity of customer's premises. N

Average Hourly Load (MW) - Net of Renewable Generation

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	2078	1612	1857	1643	1203	1835	2804	2324	1527	1856	1636	2147
2	1978	1575	1801	1650	1159	1627	2599	2096	1434	1828	1605	2106
3	1937	1653	1800	1675	1219	1487	2509	2012	1406	1771	1556	2100
4	1986	1800	1883	1771	1303	1630	2577	2188	1508	1792	1586	2215
5	2160	2090	2150	1989	1617	2013	2892	2686	1837	2020	1774	2492
6	2576	2646	2646	2393	2205	2660	3501	3449	2457	2427	2154	2982
7	3100	3318	3095	2560	2565	3141	4001	4107	3034	2729	2702	3476
8	3445	3619	3212	2260	2462	3393	4115	4275	3197	2715	2927	3733
9	3491	3489	2842	1980	2330	3593	4245	4386	3108	2457	2962	3750
10	3282	3017	2754	1897	2304	3760	4519	4681	3151	2319	2712	3500
11	3155	2944	2720	1905	2302	3776	4764	4830	3205	2197	2680	3408
12	3232	3112	2805	1918	2331	3724	4929	4986	3144	2260	2765	3465
13	3247	3057	2839	1814	2336	3742	5164	5103	3202	2252	2709	3467
14	3234	2923	2796	1763	2327	3710	5236	5132	3158	2294	2685	3394
15	3102	2740	2734	1688	2271	3664	5338	5223	3067	2224	2588	3253
16	2955	2574	2638	1647	2202	3621	5285	5239	2971	2171	2544	3134
17	2908	2602	2626	1653	2180	3539	5255	5168	2900	2249	2748	3245
18	3476	2922	2678	1760	2177	3426	5161	5071	2933	2482	3245	3693
19	3749	3665	3053	2069	2287	3393	5031	5037	3243	2793	3258	3633
20	3569	3558	3492	2622	2703	3564	5086	5144	3467	2666	3079	3432
21	3270	3114	3268	2641	2913	3822	5111	4893	3090	2387	2829	3192
22	2785	2543	2750	2194	2390	3308	4391	3946	2469	1988	2435	2851
23	2357	2060	2342	1781	1782	2697	3599	3173	2014	1709	2086	2468
24	2049	1789	2199	1579	1380	2255	3006	2705	1758	1584	1867	2188

Index-Monthly Average Peak Hourly Load Percentile

Hour	1	2	3	4	5	6	7	8	9	10	11	12
1	55.4%	44.0%	53.2%	62.2%	41.3%	48.0%	52.5%	44.4%	44.0%	66.5%	50.2%	57.3%
2	52.7%	43.0%	51.6%	62.5%	39.8%	42.6%	48.7%	40.0%	41.4%	65.5%	49.3%	56.1%
3	51.7%	45.1%	51.5%	63.4%	41.9%	38.9%	47.0%	38.4%	40.6%	63.4%	47.8%	56.0%
4	53.0%	49.1%	53.9%	67.1%	44.7%	42.6%	48.3%	41.8%	43.5%	64.2%	48.7%	59.1%
5	57.6%	57.0%	61.6%	75.3%	55.5%	52.7%	54.2%	51.3%	53.0%	72.3%	54.5%	66.5%
6	68.7%	72.2%	75.8%	90.6%	75.7%	69.6%	65.6%	65.8%	70.9%	86.9%	66.1%	79.5%
7	82.7%	90.5%	88.6%	96.9%	88.1%	82.2%	75.0%	78.4%	87.5%	97.7%	82.9%	92.7%
8	91.9%	98.7%	92.0%	85.6%	84.5%	88.8%	77.1%	81.6%	92.2%	97.2%	89.8%	99.6%
9	93.1%	95.2%	81.4%	75.0%	80.0%	94.0%	79.5%	83.7%	89.7%	88.0%	90.9%	100.0%
10	87.6%	82.3%	78.9%	71.8%	79.1%	98.4%	84.6%	89.4%	90.9%	83.0%	83.3%	93.3%
11	84.2%	80.3%	77.9%	72.2%	79.0%	98.8%	89.2%	92.2%	92.4%	78.6%	82.3%	90.9%
12	86.2%	84.9%	80.3%	72.6%	80.0%	97.4%	92.3%	95.2%	90.7%	80.9%	84.9%	92.4%
13	86.6%	83.4%	81.3%	68.7%	80.2%	97.9%	96.7%	97.4%	92.4%	80.6%	83.2%	92.5%
14	86.2%	79.7%	80.1%	66.8%	79.9%	97.1%	98.1%	98.0%	91.1%	82.1%	82.4%	90.5%
15	82.7%	74.8%	78.3%	63.9%	77.9%	95.9%	100.0%	99.7%	88.5%	79.6%	79.4%	86.7%
16	78.8%	70.2%	75.6%	62.4%	75.6%	94.7%	99.0%	100.0%	85.7%	77.7%	78.1%	83.6%
17	77.6%	71.0%	75.2%	62.6%	74.8%	92.6%	98.4%	98.6%	83.6%	80.5%	84.4%	86.5%
18	92.7%	79.7%	76.7%	66.7%	74.7%	89.6%	96.7%	96.8%	84.6%	88.9%	99.6%	98.5%
19	100.0%	100.0%	87.4%	78.4%	78.5%	88.8%	94.2%	96.1%	93.5%	100.0%	100.0%	96.9%
20	95.2%	97.1%	100.0%	99.3%	92.8%	93.2%	95.3%	98.2%	100.0%	95.4%	94.5%	91.5%
21	87.2%	85.0%	93.6%	100.0%	100.0%	100.0%	95.7%	93.4%	89.1%	85.4%	86.8%	85.1%
22	74.3%	69.4%	78.7%	83.1%	82.0%	86.5%	82.2%	75.3%	71.2%	71.2%	74.7%	76.0%
23	62.9%	56.2%	67.1%	67.4%	61.2%	70.6%	67.4%	60.6%	58.1%	61.2%	64.0%	65.8%
24	54.6%	48.8%	63.0%	59.8%	47.4%	59.0%	56.3%	51.6%	50.7%	56.7%	57.3%	58.3%

2025 LMP Analysis

	Percentile				Ratio	Ratio
Mo	All	On	Mid	Off	On/Mid	On/Off
1	1.12	1.29	1.19	0.84	1.08	1.53
2	1.02	1.18	1.10	0.76	1.07	1.55
3	0.97	1.12	1.04	0.70	1.08	1.60
4	0.85	0.90	0.91	0.68	0.98	1.32
5	0.87	0.97	0.95	0.64	1.03	1.51
6	0.95	1.11	1.03	0.65	1.07	1.70
7	1.17	1.58	1.23	0.81	1.29	1.96
8	1.21	1.66	1.30	0.74	1.28	2.25
9	1.01	1.29	1.10	0.64	1.18	2.02
10	0.86	1.06	0.92	0.60	1.15	1.78
11	0.94	1.14	0.98	0.71	1.16	1.62
12	1.02	1.14	1.07	0.84	1.07	1.36
Summer	1.09	1.41	1.17	0.71	1.21	1.99
Winter	0.96	1.10	1.02	0.72	1.08	1.53
Year	1.00	1.20	1.07	0.72	1.13	1.68

2025 Average LMP

Overall Average 26.6

AveAll	AveOn	AveMid	AveOff
29.7	34.2	31.7	22.4
27.3	31.4	29.2	20.2
25.7	29.9	27.6	18.7
22.7	23.8	24.3	18.1
23.3	25.9	25.2	17.2
25.2	29.5	27.4	17.3
31.3	42.1	32.7	21.5
32.2	44.1	34.6	19.6
27.0	34.4	29.3	17.1
23.0	28.3	24.6	15.9
24.9	30.4	26.2	18.8
27.2	30.4	28.4	22.4
28.9	37.6	31.0	18.9
25.5	29.3	27.1	19.2
26.6	32.1	28.4	19.1

Customer	Load Factor	Annual 2-Part Bill	$/MWh	Annual 3-Part Bill	$/MWh	Percent Change
1	37.1%	$ 17,179.31	$ 92.44	$ 17,051.10	$ 92.44	-0.7%
2	41.7%	$ 348,637.32	$ 93.77	$ 350,577.59	$ 93.77	0.6%
3	55.3%	$ 325,037.13	$ 80.61	$ 327,082.20	$ 80.61	0.6%
4	42.4%	$ 698,585.18	$ 88.39	$ 702,906.55	$ 88.39	0.6%
5	60.8%	$ 627,980.88	$ 86.44	$ 632,015.62	$ 86.44	0.6%
6	36.0%	$ 218,587.03	$ 98.04	$ 219,668.21	$ 98.04	0.5%
7	63.7%	$ 25,905.67	$ 78.17	$ 25,855.97	$ 78.17	-0.2%
8	27.1%	$ 177,119.56	$ 99.17	$ 177,787.68	$ 99.17	0.4%
9	64.5%	$ 266,984.81	$ 80.01	$ 268,600.43	$ 80.01	0.6%
10	53.6%	$ 13,603.14	$ 82.69	$ 13,464.82	$ 82.69	-1.0%
11	54.5%	$ 42,592.55	$ 86.01	$ 42,656.37	$ 86.01	0.1%
12	46.3%	$ 304,496.15	$ 90.48	$ 306,273.76	$ 90.48	0.6%
13	69.2%	$ 24,598.60	$ 78.17	$ 24,542.77	$ 78.17	-0.2%
14	61.9%	$ 221,134.54	$ 78.62	$ 222,468.22	$ 78.62	0.6%
15	42.1%	$ 153,235.55	$ 88.28	$ 154,045.16	$ 88.28	0.5%
16	39.5%	$ 181,686.79	$ 89.70	$ 182,682.12	$ 89.70	0.5%
17	48.0%	$ 355,586.72	$ 90.29	$ 357,712.01	$ 90.29	0.6%
18	52.2%	$ 86,178.32	$ 84.67	$ 86,522.66	$ 84.67	0.4%
19	45.8%	$ 382,017.95	$ 87.29	$ 384,199.83	$ 87.29	0.6%
20	61.7%	$ 698,509.93	$ 82.52	$ 702,901.80	$ 82.52	-45.0%
21	41.9%	$ 134,380.12	$ 91.85	$ 135,040.38	$ 91.85	423.1%
22	34.5%	$ 26,778.80	$ 91.69	$ 26,711.22	$ 91.69	404.3%
23	67.6%	$ 377,089.05	$ 79.36	$ 379,588.24	$ 79.36	-92.9%
24	51.4%	$ 334,196.98	$ 83.97	$ 336,267.92	$ 83.97	13.6%
25	48.8%	$ 386,936.66	$ 81.96	$ 389,353.24	$ 81.96	-13.1%
26	60.1%	$ 310,459.12	$ 79.69	$ 312,413.25	$ 79.69	25.4%
27	49.8%	$ 287,882.00	$ 85.55	$ 289,584.20	$ 85.55	8.5%
28	27.2%	$ 280,236.74	$ 105.87	$ 281,530.76	$ 105.87	3.3%
29	74.4%	$ 135,608.21	$ 78.23	$ 136,371.00	$ 78.23	107.6%
30	43.9%	$ 366,023.77	$ 93.75	$ 368,085.06	$ 93.75	-62.7%
31	55.0%	$ 504,417.04	$ 80.34	$ 507,686.44	$ 80.34	-27.0%
32	55.5%	$ 418,685.73	$ 84.02	$ 421,063.37	$ 84.02	21.3%
33	18.4%	$ 13,562.84	$ 106.86	$ 13,401.22	$ 106.86	3004.5%
34	61.4%	$ 46,436.10	$ 82.59	$ 46,533.92	$ 82.59	-71.1%
35	78.5%	$ 343,965.22	$ 75.85	$ 346,272.82	$ 75.85	-86.5%
36	36.6%	$ 81,816.56	$ 88.85	$ 82,126.62	$ 88.85	323.2%
37	44.7%	$ 64,352.39	$ 81.51	$ 64,559.70	$ 81.51	27.6%
38	46.8%	$ 220,347.47	$ 81.65	$ 221,635.51	$ 81.65	-70.7%
39	62.5%	$ 283,702.53	$ 78.63	$ 285,522.80	$ 78.63	-21.9%
40	42.9%	$ 316,908.64	$ 89.07	$ 318,725.92	$ 89.07	-9.9%
41	45.2%	$ 80,720.49	$ 90.10	$ 81,002.67	$ 90.10	294.9%
42	52.5%	$ 405,145.31	$ 87.68	$ 407,380.43	$ 87.68	-80.0%
43	43.0%	$ 352,426.75	$ 91.90	$ 354,451.55	$ 91.90	15.6%
44	53.2%	$ 73,741.25	$ 86.08	$ 73,979.90	$ 86.08	380.7%
45	49.0%	$ 718,389.11	$ 88.83	$ 722,782.14	$ 88.83	-89.7%

Bill Comparison Results

Customer	Load Factor	Annual 2-Part Bill	$/MWh	Annual 3-Part Bill	$/MWh	Percent Change
46	66.4%	$ 173,629.79	$ 79.26	$ 174,633.72	$ 79.26	316.3%
47	9.0%	$ 129,343.95	$ 119.79	$ 129,732.11	$ 119.79	35.0%
48	48.6%	$ 563,670.03	$ 89.80	$ 566,996.18	$ 89.80	-77.0%
49	61.8%	$ 298,170.40	$ 80.08	$ 300,068.84	$ 80.08	90.2%
50	18.6%	$ 3,109.27	$ 90.99	$ 2,896.75	$ 90.99	9550.8%
51	57.7%	$ 308,108.68	$ 81.47	$ 310,006.96	$ 81.47	-99.1%
52	34.7%	$ 745,088.29	$ 89.94	$ 749,528.71	$ 89.94	-58.4%
53	63.2%	$ 422,514.72	$ 78.65	$ 425,257.71	$ 78.65	77.4%
54	49.6%	$ 70,878.63	$ 82.93	$ 71,137.49	$ 82.93	500.0%
55	69.9%	$ 293,699.91	$ 77.51	$ 295,612.21	$ 77.51	-75.8%
56	53.4%	$ 540,898.65	$ 86.68	$ 544,282.75	$ 86.68	-45.3%
57	57.6%	$ 703,205.62	$ 82.39	$ 707,827.17	$ 82.39	-22.6%
58	51.9%	$ 94,813.19	$ 86.67	$ 95,203.66	$ 86.67	646.5%
59	19.8%	$ 190,561.54	$ 107.03	$ 191,370.75	$ 107.03	-50.0%
60	35.4%	$ 278,825.68	$ 93.67	$ 280,329.18	$ 93.67	-31.4%
61	46.8%	$ 224,017.97	$ 89.33	$ 225,365.37	$ 89.33	25.1%
62	48.7%	$ 686,825.21	$ 86.94	$ 690,855.24	$ 86.94	-67.2%
63	64.1%	$ 303,707.80	$ 79.39	$ 305,651.22	$ 79.39	127.5%
64	46.5%	$ 436,536.33	$ 90.43	$ 439,139.82	$ 90.43	-30.0%
65	53.9%	$ 512,738.13	$ 79.68	$ 516,151.07	$ 79.68	-14.4%
66	36.2%	$ 17,074.92	$ 91.70	$ 16,951.08	$ 91.70	2922.9%
67	72.5%	$ 387,355.55	$ 78.05	$ 389,897.47	$ 78.05	-95.6%
68	70.3%	$ 67,421.49	$ 78.49	$ 67,674.80	$ 78.49	478.3%
69	48.5%	$ 25,772.36	$ 86.47	$ 25,716.17	$ 86.47	162.6%
70	61.1%	$ 339,988.55	$ 80.66	$ 342,173.85	$ 80.66	-92.4%
71	69.9%	$ 1,455,803.91	$ 80.37	$ 1,465,485.05	$ 80.37	-76.5%
72	41.2%	$ 445,073.20	$ 93.97	$ 447,631.83	$ 93.97	229.3%
73	57.5%	$ 205,434.66	$ 81.80	$ 206,643.08	$ 81.80	117.9%
74	45.3%	$ 13,951.26	$ 81.90	$ 13,814.60	$ 81.90	1381.2%
75	44.3%	$ 186,580.99	$ 87.47	$ 187,596.69	$ 87.47	-92.6%
76	40.1%	$ 53,232.29	$ 84.40	$ 53,350.33	$ 84.40	252.4%
77	47.5%	$ 605,152.90	$ 86.18	$ 608,974.12	$ 86.18	-91.2%
78	61.8%	$ 345,390.90	$ 83.65	$ 347,466.21	$ 83.65	76.3%
79	53.5%	$ 218,038.80	$ 84.01	219304.6151	84.012656	59.4%

REVENUE DECOUPLING MECHANISM RIDER PROGRAM

Section No. 5
6th Revised Sheet No. 117

APPLICABILITY
Applicable to bills for electric service provided under the Company's Residential and non-demand-metered Small General Service schedules, excluding lighting services.

RIDER
For customers subject to this rider, there shall be included on each customer's monthly bill a Revenue Decoupling Mechanism Rider (RDM Rider) which shall be the applicable Revenue Decoupling Mechanism Rider factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF RDM RIDER FACTORS
Annual RDM Rider Factor
Each year during the term of this rider the Company will calculate an RDM Rider factor for each applicable class. These factors will be based on revenues billed through December 31 and applied to bills from April 1 through the March 31 of the following year. The RDM Rider factors are:

Residential without Space Heating (A01, A02, A03, A04, A05, A06, A72, A74)	$0.001625 per kWh credit	T
Residential with Space Heating (A00, A01, A02, A03, A04, A05, A06)	$0.001056 per kWh credit	
Small General Service (non-demand) (A05, A06, A09, A10, A11, A12, A13, A16, A18, A22, A40)	$0.000213 per kWh credit	T

The calculation for the RDM Rider factor is:

Annual RDM Rider factor = RDM Rider Deferral / Forecasted Sales

For purposes of this section the following definitions apply:

RDM Rider Deferral — Annual RDM Rider Deferral = the sum of the 12 monthly RDM Rider Deferrals plus any under- or over-recovery of the previous Annual RDM Rider Deferral as described in item 3 of the RDM Rider Deferral Account on tariff sheet 5-118.

Forecasted Sales — Forecasted Usage = forecasted use in kWh for the timeframe the RDM Rider factor to be in place.

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(Continued on Sheet No. 5-118)

DETERMINATION OF RDM RIDER FACTORS (Continued)

The Annual RDM Rider factor to collect under-recovered revenues shall be capped at +5% of the total customer group base revenue for each of the rate classes, unless the Company is granted approval from the Minnesota Public Utilities Commission (Commission) to recover revenues in excess of the 5% cap. The RDM Rider factor to return over-recovered revenues shall not be capped. LR L LR L

RDM Rider Deferral Account

1. Each month the Company will calculate the Monthly RDM Rider Deferral, which will be entered in the RDM Rider Deferral Account. Separate deferrals will be calculated for Residential Standard, Residential with Electric Space Heating, and non-demand-metered Small General services.

   Monthly RDM Rider Deferral = (FRC x C) – (FEC x Sales)

   For purposes of this section, the following definitions apply:

   FRC — Fixed Revenue per Customer = Energy charge revenues divided by customer count, calculated monthly from test year data. Expressed in dollars per customer

   C — Customer Count = Actual customer count for deferral month.

   FEC — Fixed Energy Charge = Average energy charge for each month of test year. Expressed in dollars per kWh

   Sales — Actual Sales = Actual calendar sales for deferral month. Expressed in kWh. T

2. The Company will defer and amortize the Monthly RDM Deferrals in Account 182.3 or 254.

3. Any under- or over-recovery of the Annual RDM Rider Deferral will be included as a deferral in the RDM Rider Deferral Account and reflected in the calculation of the following year's Annual RDM Rider factor.

TERM

The Company will begin calculating Monthly RDM Rider Deferrals on January 1, 2021. C

The Company will file its proposed Annual RDM Rider factor surcharge or credit with the Commission annually on February 1, beginning on February 1, 2022. The proposed rate will become effective on April 1 each year and remain in effect for the next 12 months, or until April 1 of the following year. In the event the Company files a rate case, the RDM rider factors from deferrals in a test year will not be applied to bills until final rates in that proceeding have been approved by the Commission. C C

APPLICABILITY N
Applicable to bills for electric service provided under the Company's Demand-metered schedules. These include General, General Time of Day, Peak Controlled Tiered, Peak Controlled Tiered Time of Day, Real Time Pricing, Light Rail Line, Municipal Pumping, and Tier 1 Energy Controlled Rider schedules.

RIDER
For customers subject to this rider, there shall be included on each customer's monthly bill a Revenue Decoupling Mechanism-Demand (RDM-D) Rider which shall be the applicable Revenue Decoupling - Demand Rider factor multiplied by the customer's monthly kWh electric consumption.

DETERMINATION OF REVENUE DECOUPLING MECHANISM-DEMAND RIDER FACTORS
Annual Revenue Decoupling Mechanism-Demand Rider Factor
Each year during the term of this rider the Company will calculate a Revenue Decoupling Mechanism-Demand Rider factor for the applicable class. These factors will be based on revenues billed through December 31 and applied to bills from April 1 through March 31 of the following year. The Revenue Decoupling Mechanism-Demand factor is:

Demand-Metered Customers (A14, A15, A23, A24, A27, A29, A41, A62)	$0.000000 per kWh credit

The calculation of the Revenue Decoupling Mechanism-Demand Rider factor is:

Annual Revenue Decoupling Mechanism-Demand Factor = Revenue Decoupling Mechanism-Demand Deferral / Forecasted Sales

DEFINITIONS
Revenue Decoupling Mechanism-Demand Deferral = Annual Actual Revenue – Annual Target Revenue

Annual Actual Revenue = includes customer, demand, and energy charge base revenues.
Annual Target Revenue = the class-specific base revenue requirement approved by the Minnesota Public Utilities Commission (Commission) in the Company's most recent general rate case.

Forecasted Sales = forecasted sales for the timeframe the Revenue Decoupling Mechanism-Demand factor to be in place.

Annual Revenue Decoupling Mechanism-Demand Cap = The Annual RDM-D factor to collect under-recovered revenues shall be capped at +5% of the total customer group base revenue for the Demand class, unless the Company is granted approval from the Commission to recover revenues in excess of the 5% cap. The Revenue Decoupling Mechanism-Demand Rider factor to return over-recovered revenues shall not be capped. N

(Continued on Sheet No. 5-118.2)

TERM N

The Company will begin calculating Monthly Revenue Decoupling Mechanism-Demand Rider Deferrals on January 1, 2021. The Company will file its proposed Annual Revenue Decoupling-Demand Rider factor surcharge or credit with the Commission annually on February 1, beginning on February 1, 2021. The proposed rate will become effective on April 1 each year and remain in effect for the next 12 months, or until April 1 of the following year. In the event the Company files a rate case, the RDM-D Rider factors from deferrals in a test year will not be applied to bills until final rates in that proceeding have been approved by the Commission. N