Volume 2B

Direct Testimony and Supporting Schedules:

David G. Prazak

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Prefiled Direct Testimony and Schedules of David G. Prazak - Volume 2B - Redacted
Otter Tail Power Company

Before the North Dakota Public Service Commission
State of North Dakota

In the Matter of the Application of Otter Tail Power Company
For Authority to Increase Rates for Electric Utility
Service in North Dakota

Case No. PU-23-

Exhibit___

RATE DESIGN AND TARIFF CHANGES

Direct Testimony and Schedules of

DAVID G. PRAZAK

PUBLIC DOCUMENT –

NOT PUBLIC (OR PRIVILEGED) DATA HAS BEEN EXCISED

November 2, 2023

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ATTACHED SCHEDULES

I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND CURRENT EMPLOYER.

A. My Name is David G. Prazak. I am employed by Otter Tail Power Company (OTP or the Company).

Q. PLEASE SUMMARIZE YOUR CURRENT RESPONSIBILITIES.

A. I am the Manager of Pricing and Rate Design. I am responsible for managing the design and implementation of retail pricing strategies for rate schedule and contract pricing, including rates and rate design and load research.

Q. HAVE YOU INCLUDED AN ATTACHMENT OF YOUR QUALIFICATIONS AND EXPERIENCE?

A. Yes. A summary of my qualifications and experience is included as Exhibit___(DGP-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. My Direct Testimony: (1) describes the rate structure objectives that were used in developing OTP's proposed rates; (2) explains the role of embedded and marginal costs in OTP's rate design; (3) describes the proposed rate design for OTP's rate schedules; (4) introduces new rate structure designs, and (5) supports the proposed language changes of OTP's rate schedule provisions.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF YOUR DIRECT TESTIMONY.

A. OTP's rate design provides a reasonable opportunity to achieve OTP's revenue requirement. The rate design is based on marginal costs, and, as such, promotes efficient use of resources.

Q. HOW IS YOUR DIRECT TESTIMONY ORGANIZED?

A. In Section III, I discuss OTP's rate design process, including the objectives that guide our rate design and the role of marginal costs in rate design. In Section IV, I discuss the rate restructuring initiative and rate changes since our last rate case, Section V identifies our rate design proposals for each customer class. Section VI identifies other rate offerings and Section VII identifies tariff changes other than rates.

Q. ARE YOU SPONSORING ANY OF THE ADDITIONAL SUPPORTING FINANCIAL DATA IN VOLUME 3 OF OTP'S APPLICATION?

A. Yes. I am sponsoring Schedules E-1 and E-2 included in Volume 3, both of which show operating revenues under present and proposed rates.[1]

Q. DID OTP IDENTIFY AN ISSUE WITH THE PROPOSED REVENUE DATA IN SCHEDULES E-1 AND E-2 AS IT FINALIZED THIS CASE FOR SUBMISSION?

A. Yes. OTP determined that credits associated with certain voluntary riders were treated incorrectly in the development of proposed operating revenues, resulting in proposed energy charges being slightly overstated. For context, the credits are equal to only approximately 0.50 percent of total proposed energy-charge revenue for the 2024 Test Year. OTP will correct this issue in the development of final rates.

III. RATE DESIGN PROCESS

A. Overall Rate Structure Objectives

Q. WHAT ARE THE RATE STRUCTURE OBJECTIVES THAT GUIDE OTP'S PROPOSAL IN THIS CASE?

A. OTP identified the following rate structure objectives:

- The rate design should give OTP a reasonable opportunity to achieve its revenue requirement. This implies rate structures that follow OTP's marginal cost structure, thereby allowing revenues to track costs.
- The rate design should promote efficient use of resources. This implies giving consumers price signals that reflect marginal costs, including seasonal differences and, where reasonably possible, time of day (TOD) differences.

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[1] Please note, Volume 3, Schedule E-2 excludes the billing determinants for the Super Large General Service (SLGS) rate and only shows total revenue, rather than its component parts (i.e., energy, demand, fixed) in order to protect an individual customer's data. As discussed in Schedule 2 to the Direct Testimony of OTP witness Ms. Tammy K. Mortenson, some present revenues are calculated using weighted composite prices. There can be slight differences between present revenues calculated using the composite pricing approach versus pricing rate code-level billing determinants. We have identified the effect of those differences in Volume 3, Schedule E-2, as the "Revenue Adjustment" line item. The cumulative difference of these adjustments is ($106,449), or less than 0.052% of total present base revenues.

- Rate design changes should be gradual where necessary to avoid abrupt bill impacts.
- The rate design should be based on structures that are reasonable and nondiscriminatory. This includes minimizing cross-subsidies within rate classes to the extent reasonably possible.
- The rate design should result in rates that are administratively feasible. This includes taking metering and billing system constraints into account and avoiding unnecessary complexity that might confuse customers.
- The rate design should preserve the attractiveness of load control/interruptible riders, as those riders provide substantial benefits to all OTP customers.

B. Role of Embedded and Marginal Costs in Rate Design

Q. PLEASE SUMMARIZE THE MAIN POINTS OF THIS PORTION OF YOUR DIRECT TESTIMONY.

A. This portion of my Direct Testimony makes two main points:

- Consistent with OTP's rate design objectives, I based our rate structures on OTP's marginal costs, tempered by the need to control bill impacts and maintain a suitable inter- and intra-class relationship between the regular rates and riders available to OTP's customers.
- The proposed intra-class revenue requirement allocation was determined by applying the Equal Percentage Marginal Cost (EPMC) methodology, where applicable. The EPMC method follows our rate structure objectives by improving the efficiency of price signals and reducing cross-subsidies.

Q. WHAT IS THE STARTING POINT FOR THE RATE DESIGN?

A. The rate design begins with the customer class base revenue responsibilities shown in Schedule 7 to the Direct Testimony of OTP witness Ms. Amber M. Stalboerger. I then take those class base revenue responsibilities and allocate them to rate classes. Finally, I develop the individual rate components (energy charges, demand charges, and fixed charges) for each rate class, based on marginal costs, which are designed to recover the overall revenue requirement.

Q. WHAT IS THE DIFFERENCE BETWEEN A CUSTOMER CLASS AND A RATE CLASS?

A. A customer class is a group of customers with similar usage patterns and electrical facilities. Customers within the customer class may have more than one rate option – or rate class. For example, the Residential customer class has two rates: a general service rate and a demand-controlled rate, each with their own applicability requirements.

Q. ARE THE CLASS REVENUE RESPONSIBILITIES DEVELOPED BY MS. STALBOERGER BASED ON EMBEDDED COSTS?

A. Yes. OTP's revenue requirement and class revenue responsibilities are calculated to recover the cost of service, which is measured by embedded costs.

Q. HOW ARE MARGINAL COSTS USED IN THE RATE DESIGN PROCESS?

A. Marginal costs are used in the process of allocating class revenue responsibilities to rate classes and in the development of individual rate components. I describe the allocation of class revenue responsibilities to rate classes in this section of my Direct Testimony and focus on the development of individual rate components in Section V, below.

Q. ARE THERE BENEFITS OF USING BOTH EMBEDDED AND MARGINAL COSTS IN RATE DESIGN?

A. Yes. Rates must give the utility the opportunity to recover its embedded costs. By using marginal costs to design those rates, OTP's rate design maintains the benefits of marginal cost price signals while still producing overall revenues that recover the cost of service. The benefits of marginal cost price signals include designing rates with seasonal, and where possible, time of day differences, and promoting the efficient use of electricity through appropriate price signals.

1. Marginal Cost Study

Q. WHAT IS THE DIFFERENCE BETWEEN MARGINAL COSTS AND EMBEDDED COSTS?

A. The most important difference between these two types of costs are historical costs (embedded) versus future costs (marginal). Marginal cost, as defined in OTP's marginal cost studies, is the change in total cost of service with respect to a small change in demand of a product or service. These marginal costs take into consideration changes in forecasted investments at various service levels and their impacts on utility system operations.

Q. HOW ARE MARGINAL COSTS DEVELOPED?

A. OTP engaged Ms. Amparo Nieto of Charles River Associates (CRA) to develop a marginal cost study covering the period 2024-2028 applicable to service in our three retail jurisdictions (the 2024 Marginal Cost Study). The 2024 Marginal Cost Study was developed with input from OTP staff regarding OTP's planning and operating practices, regional market price data, and system characteristics. OTP staff has also closely reviewed the 2024 Marginal Cost Study to make sure it does in fact reflect OTP's marginal costs. A copy of the 2024 Marginal Cost Study is included as Exhibit___(DGP-1), Schedule 2.

Q. HOW ARE THE RESULTS OF THE 2024 MARGINAL COST STUDY APPLIED TO THE RATE DESIGN PROPOSAL?

A. The 2024 Marginal Cost Study provides an accurate calculation of current marginal costs and was used to guide our rate design proposals. Notably, those marginal costs are very different from those calculated in the marginal cost study filed in our last rate case (the 2018 Marginal Cost Study), reflecting changes in the industry's marketplace.

Q. WHAT ARE THE MAIN DIFFERENCES IN THE RESULTS OF THE 2024 MARGINAL COST STUDY AND THE RESULTS OF THE 2018 MARGINAL COST STUDY?

A. All marginal energy costs have increased, and seasonal marginal capacity costs have decreased. For example:

- Annual, summer and winter marginal <u>energy</u> costs are higher in the 2024 Marginal Cost Study than they were in the 2018 Marginal Cost Study. Annual marginal energy costs have increased by 82 percent, winter marginal energy costs have increased by 88 percent and summer marginal energy costs have increased 70 percent.
- Annual marginal <u>capacity</u> costs have decreased 33 percent, with summer marginal capacity costs decreasing by 65 percent and winter marginal capacity costs slightly increasing by 6 percent.

Q. WHAT IS DRIVING THESE CHANGES?

A. There are two general drivers. First, marginal costs should reflect the wholesale marketplace. The wholesale market is influenced by any number of factors, including federal and state energy policies, various generation mixes, improvements in transmission capability, other infrastructure investment, and energy consumers themselves. These factors are combining in the Midcontinent Independent System Operator (MISO) market in a way that results in a general trend of higher energy prices and lower capacity costs for the near-term, primarily from higher natural gas prices.

The second driver is the allocation of marginal capacity costs both seasonally and in the time of day periods. Both summer and winter energy costs in the time of day periods increased similarly, with winter off-peak more than doubling. Summer generation capacity costs were reduced by about two-thirds, whereas winter capacity costs increases were fairly steady. Another marginal capacity cost, distribution substation and truckline feeder costs, has increased by 57 percent. This is not overly surprising, as supply chains for the utility sector were impacted during the COVID-19 pandemic and continue to be challenged. Additionally, the distribution substation probability of peak has moved from summer (2018 Marginal Cost Study) to winter (current study). The allocation of these winter costs is now more concentrated during the on-peak period.

2. Proposed Intra-Class Revenue Allocation

Q. PLEASE DESCRIBE THE PROCESS OF DEVELOPING INTRA-CLASS REVENUE ALLOCATIONS.

A. When the customer class has two or more rate classes, the class revenue responsibilities developed by Ms. Stalboerger must be further disaggregated to the rate class level before designing rates. We use a variety of methods to develop these intra-class revenue allocations, including the EPMC methodology.

Q. WHAT IS THE EPMC METHODOLOGY?

A. The EPMC method allocates the class revenue responsibilities to rate classes based on each rate class's marginal cost revenues. We determine marginal cost revenues for a rate class by multiplying the marginal cost times the rate class billing determinants. Exhibit___(DGP-1), Schedule 3 describes total marginal cost revenues by customer and rate class.

Q. CAN YOU PROVIDE AN EXAMPLE OF THE EPMC METHODOLOGY?

A. Yes. Table 1 below provides a simplified example of the "pure" version of the EPMC method, meaning it allocates class revenues to rate classes based entirely on the marginal cost revenues calculated using the results of the marginal cost study. The example is based on a customer class with two rate classes, where one rate class provides 80 percent of the overall marginal cost revenues for that customer class and the other rate class provides 20 percent of the overall marginal cost revenues for that customer class.

Table 1
Simplified EPMC Methodology Example

	Marginal Cost Revenue Percentage		Revenue Responsibility	
Rate Class A	80%	(a)		
Rate Class B	20%	(b)		
Class Revenue Responsibility			$100,000	(c)
Rate Class A			$80,000	[(a)*(c)]
Rate Class B			$20,000	[(b)*(c)]

Q. WHAT ARE THE BENEFITS OF THE EPMC METHODOLOGY?

A. The EPMC method is aligned with our rate structure objective to have efficient rates that reflect marginal costs. Using marginal cost-based revenues to allocate revenue from customer classes to rate classes sets efficient revenue targets for rates within a class.

Q. IS OTP RECOMMENDING USING THE PURE, OR UN-MODIFIED VERSION OF THE EPMC METHODOLOGY TO DEVELOP INTRA-CLASS REVENUE ALLOCATIONS IN THIS CASE?

A. Yes. As shown in Table 2, below, I recommend developing Controlled Service – Interruptible intra-class revenue allocations based on an un-modified application of the EPMC method.

Q. IS OTP PROPOSING TO USE A MODIFIED VERSION OF THE EPMC METHODOLOGY TO DEVELOP INTRA-CLASS REVENUE ALLOCATIONS FOR OTHER CUSTOMER CLASSES?

A. Yes. I recommend using a modified version of the EPMC methodology to develop intra-class revenue allocation for the General Service and Irrigation classes.

Q. WHY IS OTP PROPOSING TO USE A MODIFIED VERSION OF THE EPMC METHODOLOGY FOR THESE CLASSES?

A. The pure EPMC method can sometimes result in dramatic changes in rate class revenue responsibilities, which, in some cases, is necessary to minimize cross subsidization. However, using the modified version of the EPMC method allows us to balance the efficiency benefits of marginal cost-based rates with other important rate structure goals, like avoiding abrupt changes in intra-class revenue responsibilities. The modified EPMC method allows us to move a class more gradually towards cost, and away from cross-subsidization, without making too large a change to any one class or sub-class at any one time.

Q. PLEASE DESCRIBE THE MODIFIED VERSION OF THE EMPC METHODOLOGY YOU USED TO DEVELOP GENERAL SERVICE AND IRRIGATION INTRA-CLASS REVENUE RESPONSIBILITIES.

A. We developed General Service and Irrigation intra-class revenue responsibilities using a modified version of the EPMC method (referred to herein as EPMC Method 1). This method changes the results from strict application of EPMC within a class. Under this method, the target revenue for a rate class is 50 percent of the difference between: (1) the overall percentage revenue increase proposed by Ms. Stalboerger for the customer class; and (2) the percentage revenue increase that would result from applying EPMC to each rate class within the customer class. This approach also recognizes the goal of gradualism and takes into consideration the fact that the customer class as a whole is receiving a revenue increase.

Q. HOW WERE INTRA-CLASS REVENUE RESPONSIBILITIES DEVELOPED FOR OTHER CLASSES?

A. Intra-class revenue responsibilities for the other customer classes are based on the class-level base rate revenue increases proposed by Ms. Stalboerger. For example, Section 14.07 - Controlled Service Off Peak has a single rate schedule with three rate classes – secondary service under and over 100 kW and primary service. Ms.

Stalboerger's recommended base rate revenue increase for the Controlled Service Off Peak class is 26.52 percent. The resulting increases for two of the three rate classes that had customers were a result of the outcome of the rate designs based on marginal cost. In another example, rate classes were assigned increases equal to the base rate revenue increases prosed by Ms. Stalboerger, while others had different rate class increases. In all cases, whether we applied modified or regular EMPC, total customer class increases yielded the embedded cost revenue assignment.

Q. PLEASE IDENTIFY THE DIFFERENT APPROACHES USED TO DEVELOP INTRA-CLASS REVENUE ALLOCATIONS.

A. The table below identifies the different approaches for developing intra-class revenue allocations. Further details are provided in Schedule 3.

Table 2
Summary of Approaches to Developing Intra-Class Revenue Responsibilities for All 10 Customer Classes with Multiple Rate Classes

Customer Class	Method
Residential	Class Level Increase
Farm	Class Level Increase
General Service	EPMC Method 1
Large General Service	Class Level Increase
Irrigation	EPMC Method 1
Outdoor Lighting	Class Level Increase
Other Public Authority	Class Level Increase
Controlled Service - Interruptible	EPMC
Controlled Service - Deferred	Class Level Increase
Controlled Service – Off Peak	Class Level Increase

IV. RATE RESTRUCTURING

A. Rate Restructuring Initiative

Q. PLEASE DESCRIBE OTP'S RATE RESTRUCTURING INITIATIVE.

A. The rate restructuring initiative involved examination of rate offerings in the context of changes in the energy industry, customers, and business administration.

OTP assembled input from various departments in the Company to discuss the basics of what is, and what is not, needed – now and in the future.

Q. WHAT WAS OTP HOPING TO ACHIEVE THROUGH THE INITIATIVE?

A. OTP met to determine the goals of the initiative. Three goals emerged from our discussions:

- Achieve less complexity yet maintain flexibility;
- Recognize the balance of needs between costs/revenue requirements and customers; and
- Meet changing customer expectations.

Q. PLEASE DESCRIBE THE RESTRUCTURING FRAMEWORK DEVELOPED FROM THE GOALS.

A. The goals led us to develop five categories (5 Cs) to examine and consider during the restructuring efforts for our rate offerings.

1. *Class Structures*: examine and consider the number of customer classes utilized in our class cost of service study.
2. *Continuity/Uniformity*: examine and consider offering the same type of rate offerings in all our jurisdictions.
3. *Customer-Centric/Flexibility*: examine and consider rate offerings that address customer wants/needs, consistent with jurisdictional statutes.
4. *Consistency/Compatibility*: examine general rules and regulations as well as rate schedules to develop consistent language across jurisdictions to the extent possible under jurisdictional statutes and other requirements.
5. *Close Loopholes*: examine and consider rate offerings that reduce ambiguity and increase the intent of rate design and/or other compliance obligations.

Q. WHAT OTHER STEPS OCCURRED DURING OTP'S RATE RESTRUCTURING EFFORTS?

A. The rate restructuring team utilized the 5 Cs and assembled a list of measures to consider. The measures went through another screening step to aid in the selection of measures. The screening steps included identifying the appropriate regulatory proceeding for different measures, research, resources and other timing constraints, and items that would rely on outcomes of pending dockets. Sub-teams were assigned to examine and consider the best restructuring efforts to be included in this rate case consistent with the goals and 5 Cs framework.

Q. PLEASE DESCRIBE THE OUTCOMES OF THE RATE RESTRUCTURING EFFORTS INCLUDED IN OTP'S RATE CASE PROPOSAL.

A. The measures identified for inclusion in this rate case are as follows:

- Restructure the Residential Demand Control Rate;
- Combine two separate but related rate schedules into one (for example Small and Large Dual Fuel);
- Expand air conditioning control to additional months and increase compensation;
- Ensure consistent language among rates with billing demand/facilities charges;
- Propose customer rate schedule placement qualifications for General and Large General Service Customer rates;
- Create alignment of rate classes within the appropriate customer class;
- Review & revise allocation methodology for controlled service rates;
- Develop a special facility charge calculation to be used in Sections 5.02, 11.02 - Irrigation, and 14.12 - Bulk Interruptible;
- Examine and modify General Rules and Regulations for changing industry conditions; and
- Add a 3-month trial period to a time-differentiated rate.

Q. WHERE IN YOUR TESTIMONY DO YOU ADDRESS THE SPECIFICS OF THESE RESTRUCTURING MEASURES?

A. Changes to existing base rates due to the rate restructuring initiative are discussed in various parts of Sections V-VI. Changes to tariffs due to the rate restructuring initiative are discussed in Section VII.

B. New Rates Since Last Rate Case

Q. HAS OTP INITIATED ANY NEW BASE RATE OFFERINGS SINCE ITS LAST NORTH DAKOTA RATE CASE?

A. Yes. We added LED Street and Area Lighting Services in Case Nos. PU-21-76 and PU-22-190. Also, our Real Time Pricing and Large General Service Rider offering currently is pending in Case No. PU-23-290.

V. INDIVIDUAL RATE PROPOSALS

A. Residential Class

Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE RESIDENTIAL CLASS?

A. There are two rate schedules in the Residential Class: Residential Service (Section 9.01) and Residential – Controlled Demand (Section 9.02).

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 9.01 RESIDENTIAL SERVICE RATE.

A. We are proposing a single rate structure change for this rate: adding a fixed facility charge. This rate also includes a monthly customer charge, a minimum bill equal to the customer charge plus facilities charge, and a flat seasonally differentiated energy charge. The table below identifies proposed energy charges, which are purposely above marginal cost, but still provide a reasonably efficient price signal for residential customers. The proposed customer charge is about 100 percent of marginal cost. OTP developed marginal costs for facilities based on customer usage, a proxy for design demand, tied to transformer and other customer-related distribution equipment. The proposed fixed facility charge is $3.50/month, significantly less than marginal facilities charges under the 2024 Marginal Cost Study. By not collecting the balance of the facilities cost, about $12.00/month, OTP will collect these costs in the energy charge instead of fixed charges.

Table 3
Comparison of Current and Proposed 9.01 Residential Rate and Marginal Costs

Residential Service Section 9.01	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month		Energy Charge per kWh All Year	Summer	Winter
Current Rate	$14.00	Customer + Facilities			ENERGY	$0.08050	$0.05446
	$56.00		$0.00				
Seasonal Customer Charge				AC Credit(4 months)	-$8.25		
				Water Heating Credit	-$8.00		
Proposed Rate	$17.00	Customer + Facilities	$3.50		ENERGY	$0.07702	$0.08743
Seasonal Customer Charge	$68.00						
				AC Credit(5 months)	-$8.00		
				Water Heating Credit	-$8.00		
Marginal Costs	$17.07				All kWh	$0.05677	$0.06444
		URBAN	$15.55				
		RURAL	$87.06				

Q. ARE YOU RECOMMENDING AN INCREASE TO THE 9.01 RESIDENTIAL SERVICE RATE CUSTOMER CHARGE?

A. Yes. We are proposing a modest $3.00 per month increase in the 9.01 Residential Service customer charge.

Q. WHY DO YOU RECOMMEND AN INCREASE IN THE 9.01 RESIDENTIAL SERVICE RATE CUSTOMER CHARGE?

A. Our recommendation is informed by our rate structure objectives, specifically that rates reflect marginal costs, promote the efficient use of resources and minimize cross-subsidies within rate classes to the extent reasonably possible.

Q. HOW DOES THE PROPOSED CUSTOMER CHARGE FURTHER THESE OBJECTIVES?

A. First, the proposed customer charge moves rates essentially to marginal cost. The 2024 Marginal Cost Study indicates that marginal customer-related costs are $17.07/month. Second, when the customer charge is set below marginal cost, the balance of the costs the customer charge is designed to recover are instead recovered through volumetric charges. This means that customers with usage that exceeds the class average pay more than their fair share of the fixed cost of service. By setting the customer charge essentially at marginal cost, means that none of our customers in this class will be paying more than their fair share via volumetric charges.

Q. ARE THERE UNIQUE ELEMENTS OF OTP'S CUSTOMER POPULATION THAT MAKE INTRA-CLASS EQUITY ESPECIALLY IMPORTANT?

A. Yes. OTP's service territory is predominately rural in nature, and natural gas service is not available in many of our communities. Customers with electric heating are more likely to have usage that exceeds the class average, meaning they end up paying more than their fair share of the cost of service when customer charges are too low.

Q. WHAT ARE THE BASE RATE IMPACTS OF YOUR PROPOSED 9.01 RESIDENTIAL RATE?

A. To analyze base rate impacts from each of OTP's proposed rates, we computed an average customer's billing determinants for each customer duo-decile (20 equal segments) and calculated the base rate portion of that customer's bill under current base rates and under proposed rates for each rate schedule within each class, using 2024 Test Year forecasted billing information. We then created bar charts showing the average monthly bill changes for the duo-deciles (20 equal segments) of customers, ordered by average monthly kWh use. Each bar represents 5 percent of customer accounts in the class. It is important to keep in mind that the smallest one or two bars probably include significant numbers of customers who were not on the system for the entire year, are seasonal customers, or are anomalies such as customers who shifted from one rate to another (or shifted load to a rider) during the year.

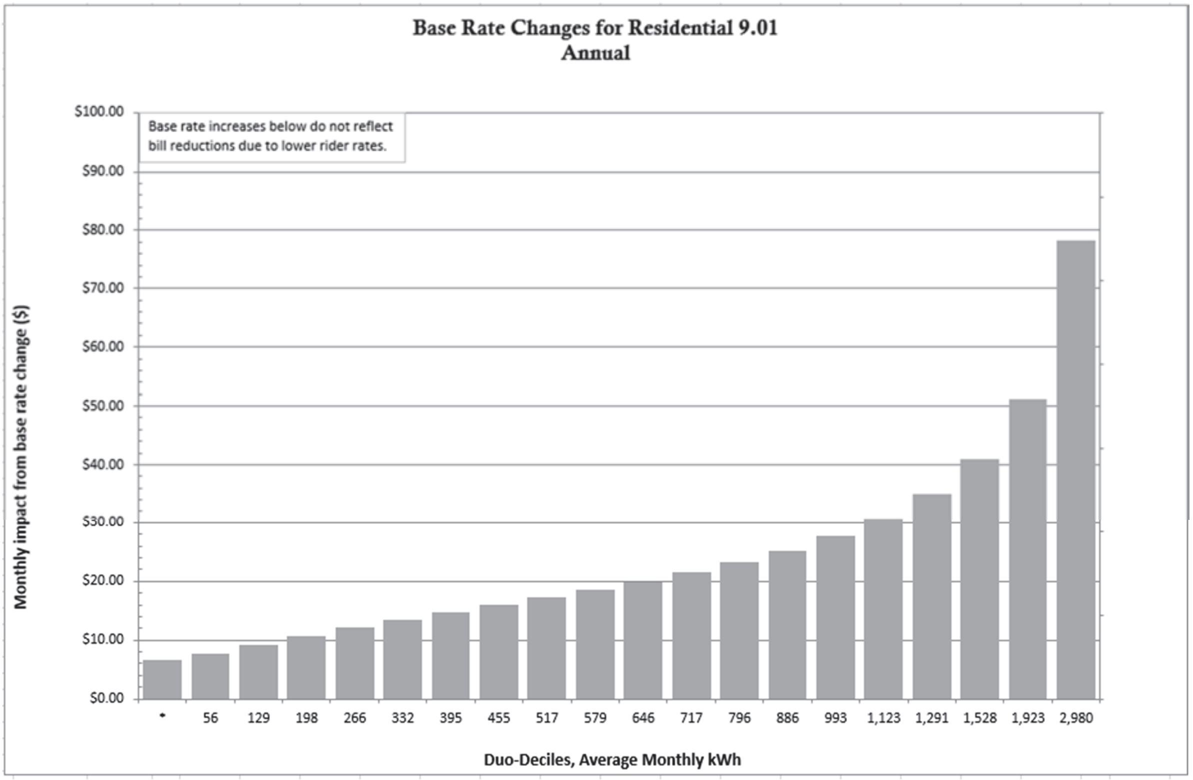
As shown in Figure 1, below, more than 75 percent of Residential customers will see the non-fuel base rate portion of their bill change by less than $30 per month.

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING THE BILL IMPACTS PRESENTED IN YOUR DIRECT TESTIMONY?

A. Yes. Figure 1 below and all subsequent duo-decile bill impacts figures *do not* account for costs moving out of base rates and associated changes to riders. They only show the base rate impact of the Company's proposals in this case. The actual *bill* impact will be lower than what is shown in the duo-decile figures due to the reduction of rider rates that is occurring as part of the movement of rider costs into base rates.[2]

[2] Volume 3, Schedule E-2 identifies the class-level net impact of the Company's proposals (i.e. increase of base rates and reduction of rider rates).

Figure 1



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 9.02 RESIDENTIAL-CONTROLLED DEMAND RATE.

A. OTP's proposed Residential Controlled Demand (RCD) rate is part of our restructuring efforts. The proposal changes how customers are charged in both the summer and winter seasons. First, summer demand charges are eliminated, and the summer energy charges are the same as the 9.01 Residential Service. Second, the proposed demand charges will continue to be levied with a 12-month ratchet, using only the winter season. The winter demand rates continue to be an important price signal as the rate is designed for reducing demand in the winter when OTP's system peaks.

As shown in the table below, the proposal continues with customer charges set near marginal costs. Similar to the Residential Service 9.01 rate, we are introducing a fixed facilities charge to collect a portion of the larger facilities costs needed for winter electric heating customers. Winter-only demand costs are set at marginal capacity costs. Lastly, the energy costs are set to obtain the remainder of the revenue requirement. The proposed energy charges, which are above marginal cost, still provide a reasonably efficient price signal. The present (i.e., current) and proposed rate components are identified in the table below.

Table 4
Comparison of Current and Proposed 9.02 Residential Controlled Demand and Marginal Costs

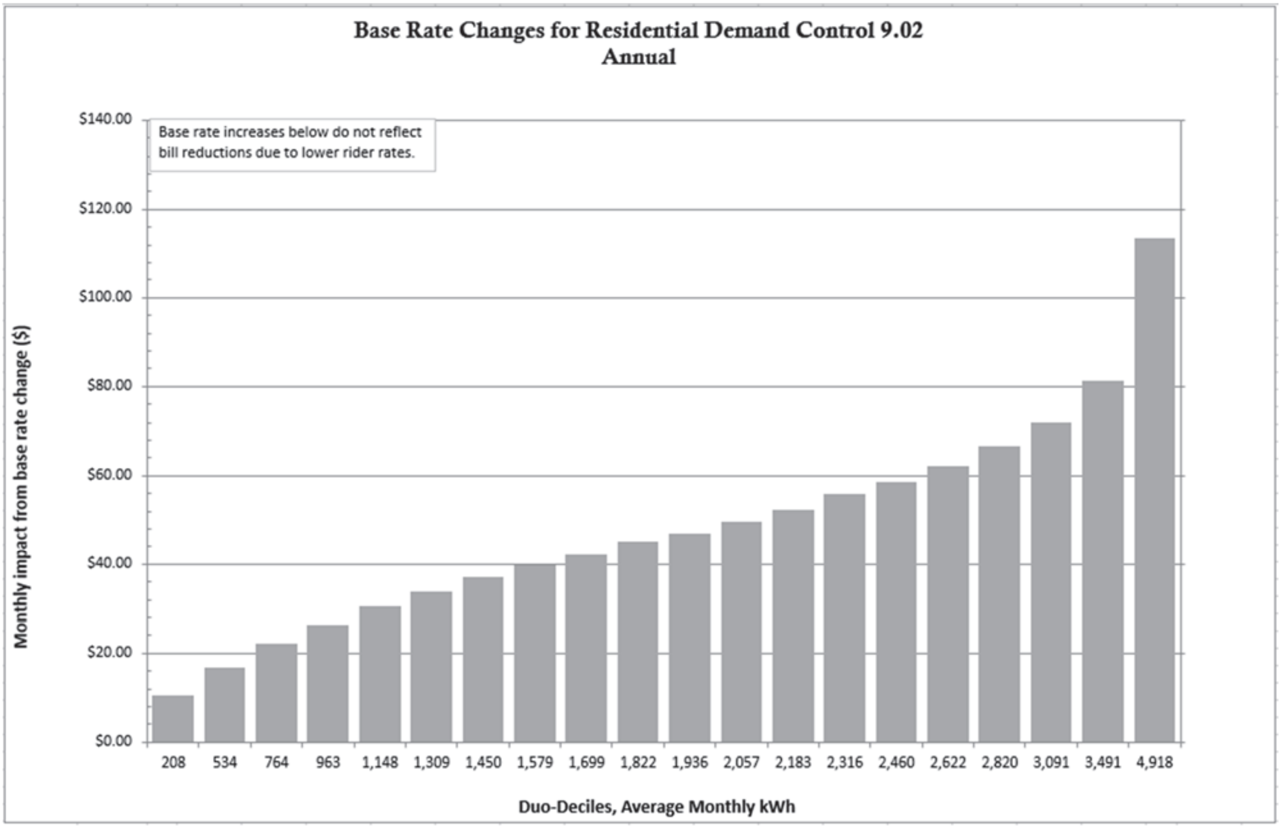
RESIDENTIAL DEMAND CONTROL SERVICE	Section 9.02									
		Customer Charge per month	Minimum Bill per month		Facilities Charge per month		Charge per kWh Summer	Charge per kWh Winter	Demand Charge per kW per mo. Summer	Demand Charge per kW per mo. Winter
Current Rate									per 12-mo. max monthly	
	Customer Charge per Month:	$20.10	Cust. + Facility + Demand Charges	Facilities Charge per Month All Customers:	$0.00	All kWh:	$0.03379	$0.03461	$8.00	$8.00
									per 12-mo. max monthly	
Proposed Rate							Summer	Winter	Summer	Winter
	Customer Charge per Month:	$21.00	Cust. + Facility + Demand Charges	Facilities Charge per Month	$7.00	All kWh:	$0.07702	$0.05106	$0.00	$11.00
							Energy Only:		Capacity Only	
Marginal Costs		$21.37					Summer	Winter	Summer	Winter
					$26.64		$0.05677	$0.05025	$0.00	$11.02

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED 9.02 RESIDENTIAL CONTROLLED DEMAND RATE?

A. The base rate impacts, shown in the figure below, result in more than 75 percent of RDC customers seeing the base rate portion of their bill change by less than $60 per month. For comparison purposes, the RDC 2024 Test-Year average customer usage is 2.5 greater than average Residential usage,[3] essentially unchanged since our last rate case.

[3] 9.02 monthly average usage: 1,969 kWh; 9.01 monthly average usage: 791 kWh.

Figure 2



B. Farm Class

Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE FARM CLASS?

A. There is one rate schedule in the Farm Class: Farm Service (Section 9.03).

Q. ARE YOU PROPOSING ANY RATE STRUCTURE CHANGES FOR THE FARM CLASS?

A. No. Our proposal includes increasing the customer charge to be slightly over marginal customer costs and increasing both facilities charges for single and three-phase customers. These charges are designed to collect a portion (less than 18 and 29 percent, respectively) of the fixed marginal costs to serve. The present and proposed rate components are identified in the table below.

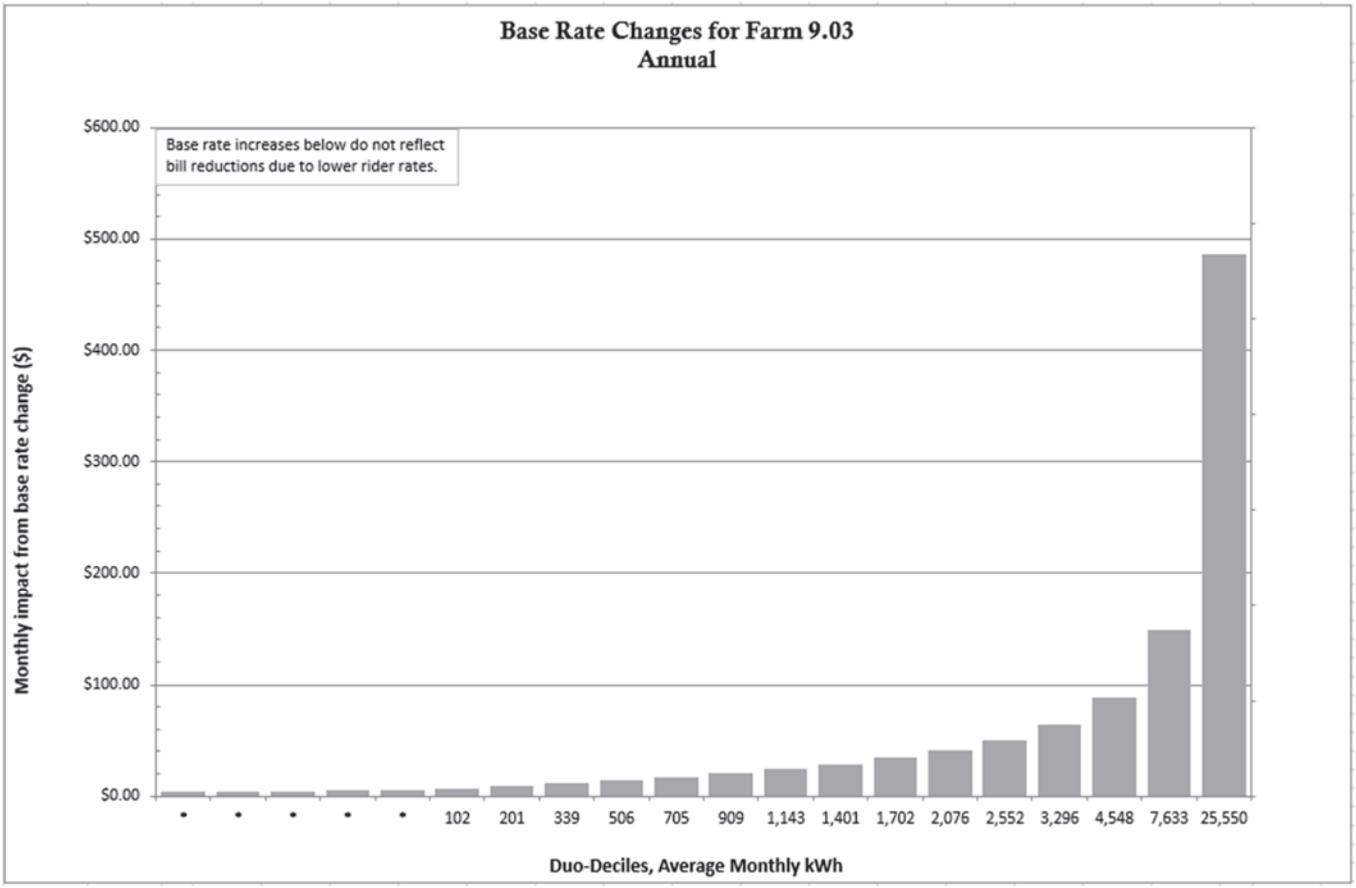
Table 5
Comparison of Current and Proposed 9.03 Farm Service and Marginal Costs

FARM SERVICE	Section 9.03						
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per kVA of Transformer			Energy per kWh Summer	Winter
Current Rates	$17.40	Cust + Fac	Facilities Charge per kVA of Transformer Single-Phase , per Month 3-Phase, per Month	 $10.00 $20.00	All kWh	$0.06793	$0.04595
Proposed	$22.00	Cust + Fac	Facilities Charge per kVA of Transformer Single-Phase , per Month 3-Phase, per Month	 $20.00 $40.00	All kWh	$0.06361	$0.07221
Marginal Costs	$21.71	Cust + Fac	Single-Phase Monthly Charge $ 3-Phase Underground > 25kVa $	112.19 139.56	All kWh	$0.05677	$0.06444

Q. WHAT ARE THE BASE BILL IMPACTS FROM YOUR PROPOSED FARM RATE?

A. As shown below, approximately 90 percent of customers (the first 18 duo-deciles) see monthly base bill increases of less than $95 per month.

Figure 3



C. General Service Class

Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE GENERAL SERVICE CLASS?

A. There are three rates within the General Service Class: Small General Service (Under 20 kW) (Section 10.01); General Service (20 kW or Greater) (Section 10.02); and General Service – Time of Use (Section 10.03).

Q. ARE YOU PROPOSING TO RESTRUCTURE RATES IN THE GENERAL SERVICE CLASS?

A. Yes, I propose structural changes to Sections 10.02 and 10.03, which I will discuss in more detail below. In summary, for both of these rates, I am proposing to close potential loopholes in these two rate schedules by limiting the ability of certain larger customers with lower load factors to move from the Large General Service rates to General Service rates, which by design has lower demand and higher energy costs.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 10.01 SMALL GENERAL SERVICE (UNDER 20 KW) RATE.

A. Changes to this rate include increasing all rate elements and adding a new fixed facilities charge per month to recover fixed charges. The customer charge is set at marginal cost, and the balance of the revenue requirement is collected in the energy charge. The present and proposed rate components are identified in the table below.

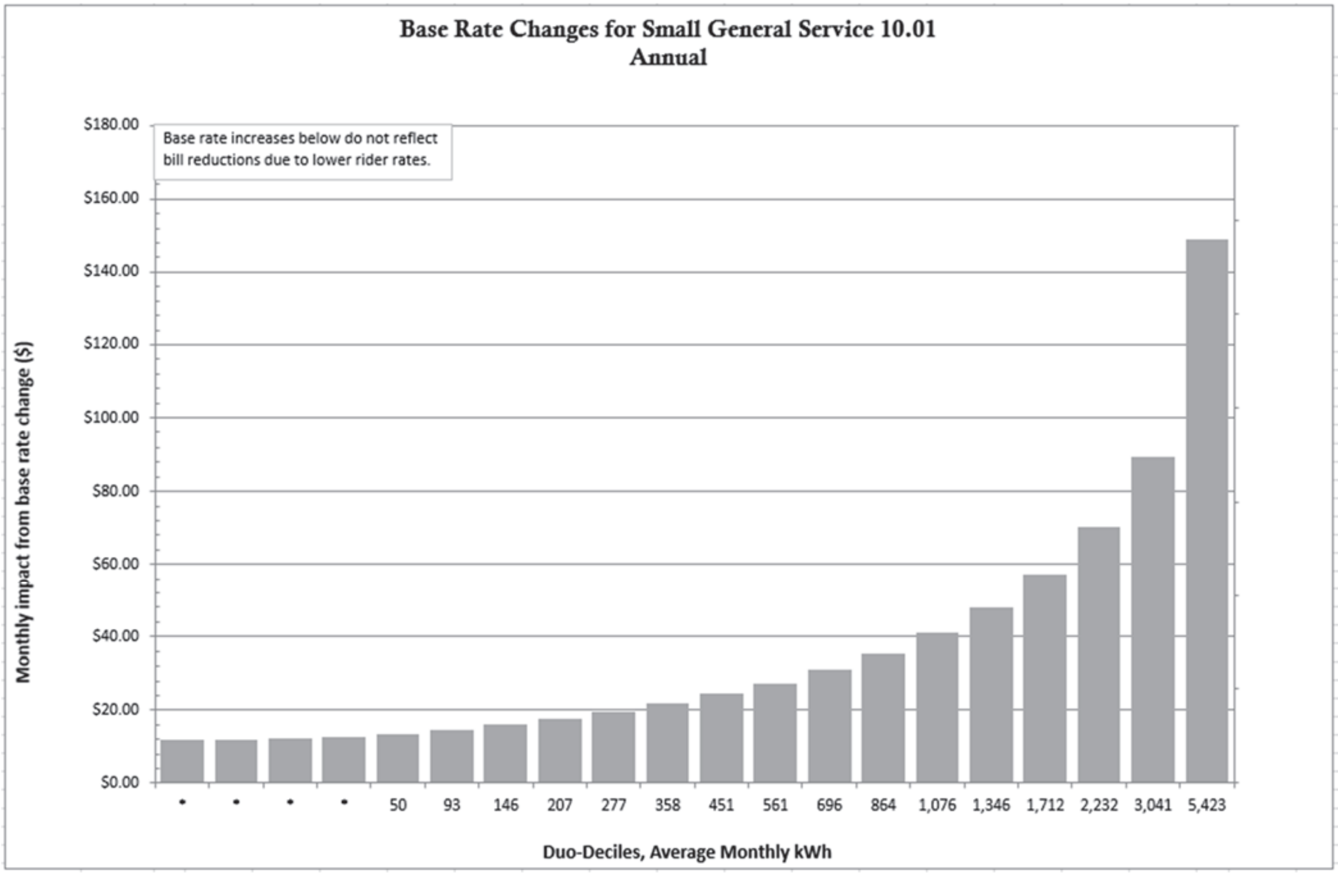
Table 6
Comparison of Current and Proposed 10.01 Small General Service (Under 20kW)
Rate and Marginal Costs

SMALL GENERAL SERVICE Under 20 KW — Section 10.01	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter
Current Rate GS					
Secondary Service	$24.90	Customer Charge & Facilities Charge	NA	$0.06682	$0.04521
Primary Service	$24.90	Customer Charge & Facilities Charge	NA	$0.06440	$0.04331
Proposed GS Rate					
Secondary Service	$24.90	Customer Charge & Facilities Charge	**$12.00**	$0.07117	$0.08079
Primary Service	$24.90	Customer Charge & Facilities Charge	**$12.00**	$0.06918	$0.07912
Marginal Costs					
Secondary Service	$24.19		$26.64	$0.05677	$0.06444
Primary Service	$24.19		$26.64	$0.05518	$0.06311

Q. WHAT ARE THE BASE BILL IMPACTS FROM YOUR PROPOSED 10.01 SMALL GENERAL SERVICE (UNDER 20 KW) RATE?

A. About 90 percent of the class (represented by the first 18 duo-deciles) will see an increase of about $70.00 per month or less.

Figure 4



Q. PLEASE DESCRIBE YOUR STRUCTURAL RATE DESIGN PROPOSAL FOR SECTIONS 10.02 AND 10.03.

A. Currently, Sections 10.02 and 10.03 have a 20kW demand threshold, whereby the customer must have a measured demand of at least 20 kW within the most recent 12-month period. Customers that do not achieve this demand threshold must take service under Schedule 10.01 (Small General Service). There is no maximum demand for Sections 10.02 and 10.03.

OTP proposes to introduce a maximum demand threshold of 200 kW to Sections 10.02 and 10.03. The addition of the maximum demand threshold is intended to prevent larger, low-load factor customers moving from Large General Service rates (which include relatively higher demand charges) to General Service rates.

Q. WHY IS OTP PROPOSING TO INTRODUCE A MAXIMUM DEMAND THRESHOLD TO ITS GENERAL SERVICE RATES?

A. The threshold is intended to close a potential loophole, whereby larger, low-load factors customers could migrate to General Service rates and achieve bill savings without any changes in electricity usage. It is important that rates be designed in a way that customer bill savings are coupled with behavioral changes that reduce system costs. Without that connection, customers can engage in rate arbitrage, eroding revenues while not producing commensurate cost savings. The shortfall ultimately would need to be borne by other customers.

Q. IS OTP PROPOSING TO ADD LANGUAGE TO SECTIONS 10.02 AND 10.03 OF ITS TARIFFS TO ADDRESS THE MAXIMUM DEMAND THRESHOLD?

A. Yes. OTP proposes to add the following language in both rate schedules:

> The Customer may remain on this schedule if the Customer's maximum monthly Billing Demand does not meet or exceed 200 kW for more than two of the most recent 12 months. If the Customer achieves an actual Billing Demand of 200 kW or greater for the third time in the most recent 12 months, the Customer will be placed by default on the Large General Service schedule (Section 10.04) in the next billing month. The Customer is also eligible for service on the Large General Service Time of Day (Section 10.05) but must direct the company to their applicable rate option.

Q. WILL THIS CHANGE BE APPLIED ON A PROSPECTIVE BASIS?

A. Yes. OTP proposes that customers on the Section 10.02 and 10.03 rates as of the date of the Commission’s final order in this proceeding be permitted to remain on the rate, even if their measured demand exceeds 200 kW. The maximum demand threshold would be applied only on a prospective basis.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR SECTION 10.02 GENERAL SERVICE.

A. OTP proposes to set the customer charge at slightly below marginal customer-related costs. The facilities charges are set at updated marginal facilities costs. Finally, we are introducing a demand charge per measured kW to improve cost assignments to customers, but at about 25 percent of marginal demand costs. The present and proposed rate components are identified in the table below.

Table 7
Comparison of Current and Proposed 10.02 General Service
(20kW or Greater)
Rate and Marginal Costs

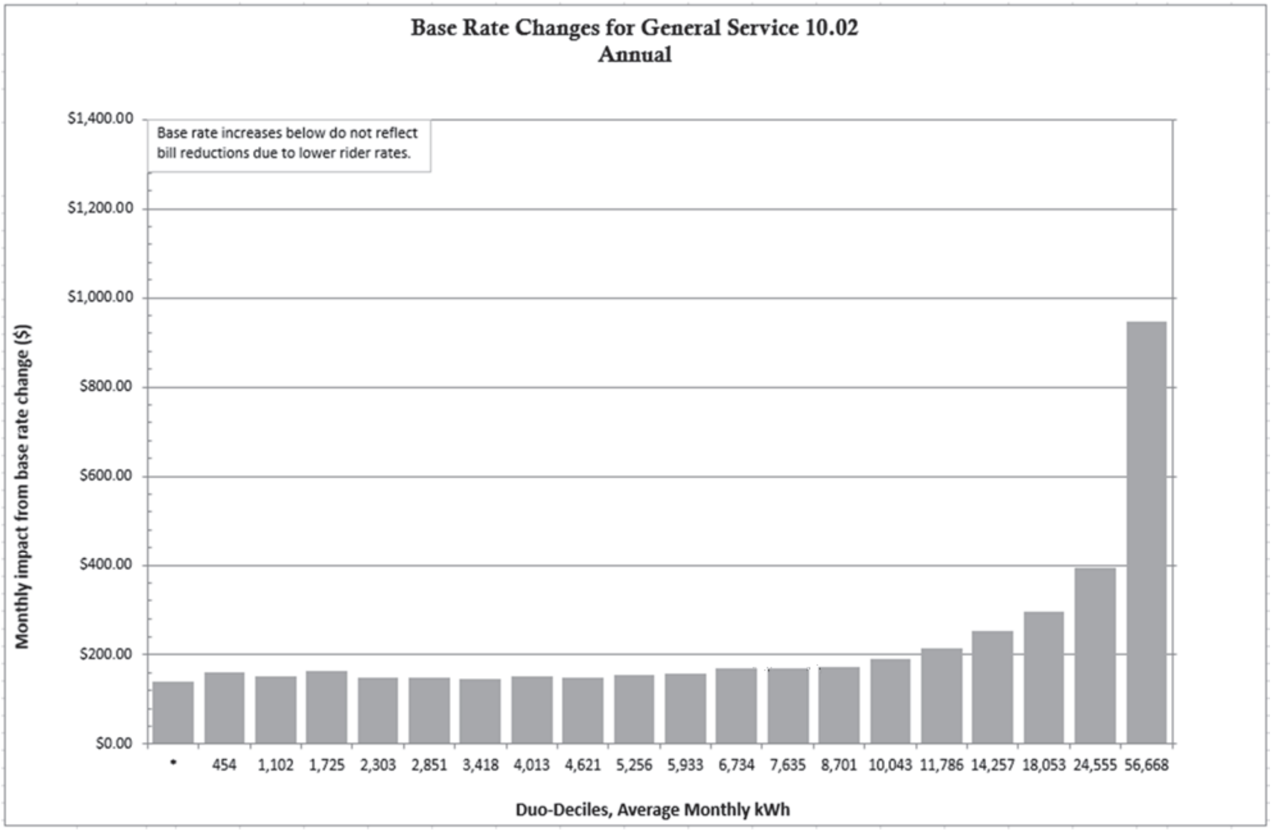
GENERAL SERVICE — Section 10.02
20 KW or Greater

	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
Current Rate							
Secondary	$31.90	Cust. + Facilities Charge	$0.98	$0.07506	$0.05078	$ -	$ -
Primary	$21.30	Cust. + Facilities Charge	$0.65 20 kW Minimum	$0.07233	$0.04865	$ -	$ -
Proposed Rate							
Secondary	**$54.00**	**Cust. + Facilities Charge**	**$2.12**	**$0.05259**	**$0.05934**	**$ 2.24**	**$ 2.75**
Primary	**$36.00**	**Cust. + Facilities Charge**	**$1.42** 20 kW Minimum	**$0.05131**	**$0.05757**	**$ 2.15**	**$ 2.62**
Marginal Costs							
Secondary	$54.23	Cust. + Facilities Charge	$2.12	$0.04453	$0.05025	$ 8.96	$ 11.02
Primary	$36.33	Cust. + Facilities Charge	$1.42	$0.04345	$0.04875	$ 8.59	$ 10.47

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED RATE CHANGES TO THIS RATE?

A. About 75 percent of customers have monthly base rate increases of about $200 per month or less.

Figure 5



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 10.03 GENERAL SERVICE-TIME OF USE RATE.

A. OTP is maintaining the customer charge, despite lower marginal customer costs, increasing distribution facilities charges to marginal cost levels, and not assigning a demand charge during the off-peak period. The present and proposed rate components are identified in the table below.

The proposed rate continues with seasonally differentiated charges and sets the on-peak (“declared peak”) energy charges at full marginal cost (i.e., energy plus demand) expected in the hours likely to be defined as system peak hours. The declared peak hours are proposed to move from approximately 100 hours per year to approximately 80 hours per year. The proposed mid-peak and off-peak energy charges are set below marginal energy costs to meet the revenue requirement not satisfied by other charges. This rate structure continues to give a strong, efficient, and transparent price signal to customers during critical hours.

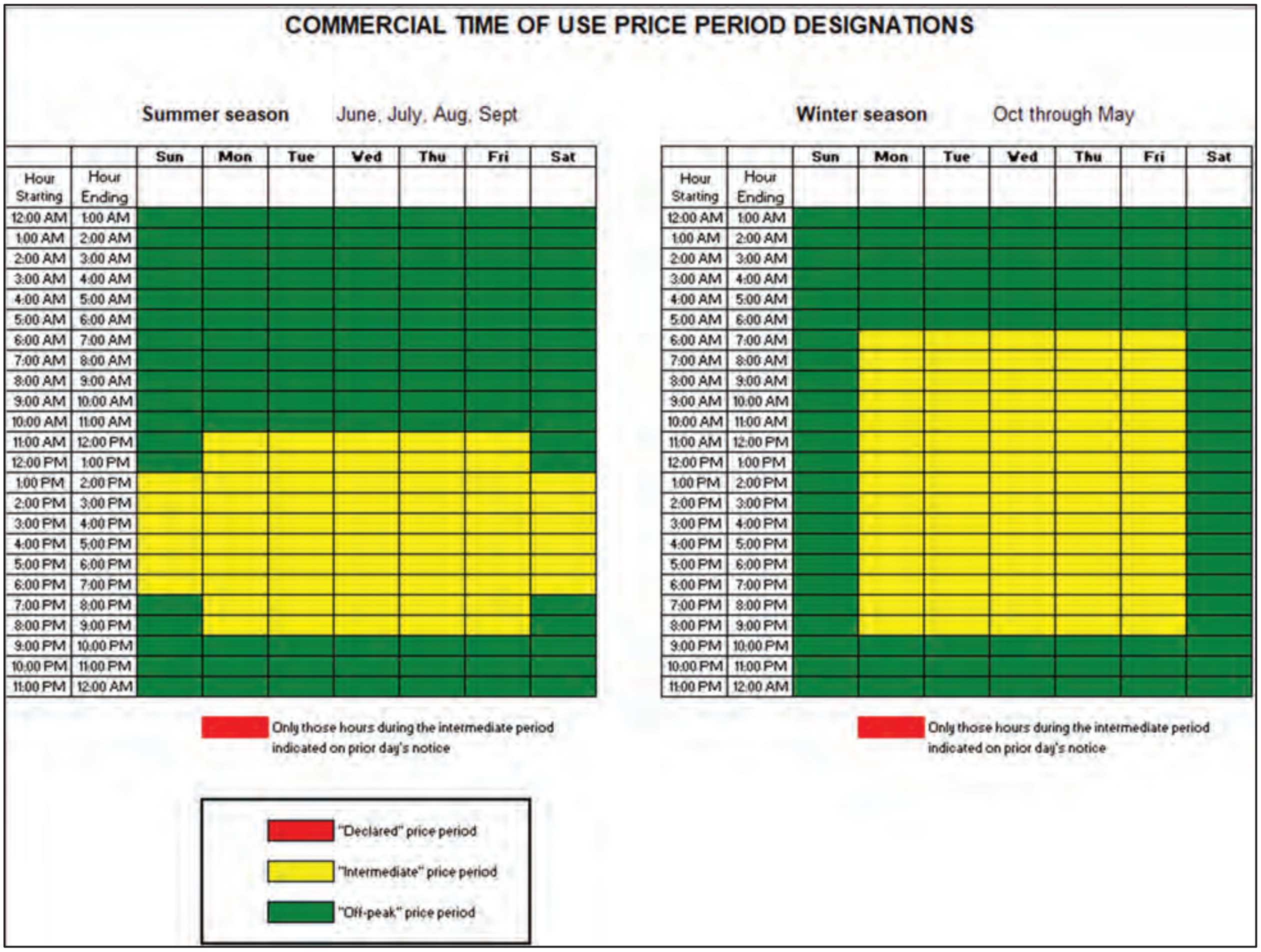
Table 8
Comparison of Current and Proposed 10.03 General Service
Time of Use
Rate and Marginal Costs

GENERAL SERVICE - TIME OF USE	Customer Charge per month	Minimum Bill per month	Facilities Charge per per KW month	Section 10.03	Charge per kWh Summer	Charge per kWh Winter	Demand Charge per kW per mo. Summer	Demand Charge per kW per mo. Winter
Current Rate							per seasonal max kW	
Seasonal Energy and Demand with Peak, Mid-Peak, Off Peak	$219.00	Cust+Fac. +min. Demand	$0.98	*Declared	$0.43264	$0.16259	NA	NA
				Intermediate	$0.02571	$0.02638	$3.44	$5.12
				Off-peak	$0.01702	$0.01845	$0.00	$0.00
Proposed							per seasonal max kW	
Seasonal Energy and Demand with Peak, Mid-Peak, Off Peak	$219.00	Cust+Fac. +min. Demand	$2.12	*Declared	$0.19539	$0.23215	NA	NA
				Intermediate	$0.03996	$0.04012	$2.57	$6.18
				Off-peak	$0.02607	$0.03452	$0.00	$0.00
					Marginal Energy		Marginal Capacity	
Marginal Costs				Declared	$0.19539	$0.23215	$0.00	$0.00
				Interm.	$0.05368	$0.05389	$2.01	$4.28
	$99.98		$2.12	Off	$0.03502	$0.04637	$0.56	$1.90

Q. ARE YOU PROPOSING TO CHANGE THE TIME OF USE PERIODS FOR THIS RATE?

A. Yes. The changes to the time of use periods are based on the results of the 2024 Marginal Cost Study. The new periods include increased off-peak and intermediate hours. The chart below shows a graphical representation of the new period definitions. Specific period definitions are included in the proposed rate schedule, which is part of Volume 2C.

Figure 6



Q. PLEASE PROVIDE A SUMMARY OF THE PROPOSED TIME PERIOD CHANGES IN THE SECTION 10.03 GENERAL SERVICE – TIME OF USE RATE.

A. The changes improve the correlation of expected market prices and the proposed time of day periods. Specifically:

- Summer weekday: added an additional off-peak hour (was shoulder) from 9pm-10pm
- Summer weekend: added additional off-peak hours (were shoulder) from 11am-1pm, 7pm-10pm
- Winter weekday: added additional off-peak (was shoulder) from 9pm-10pm
- Winter weekend: removed all shoulder, now is all off-peak (used to be 4 shoulder hours)

Q. WHAT ARE THE BASE BILL IMPACTS FROM THE PROPOSED 10.03 GENERAL SERVICE-TIME OF USE RATE?

A. A duo decile base bill impact graph was not prepared, as there is only one customer taking service on this rate.

D. Large General Service Class

Q. WHAT RATE SCHEDULES ARE INCLUDED IN THE LARGE GENERAL SERVICE CLASS?

A. There are seven rates within the Large General Service Class: Large General Service (Section 10.04), Large General Service Time of Day (Section 10.05), Super Large General Service (Section 10.06), Standby Service (Section 11.01), Real-Time Pricing Rider (Section 14.02), Large General Service Rider (Section 14.03), Economic Development Rate Rider – Large General Service (Section 14.13).

Q. ARE ANY PROPOSED RATES IN THIS CLASS A PART OF YOUR RATE RESTRUCTURING INITIATIVE?

A. Yes. Those rates include the Large General Service (10.04). Large General Service Time of Day (Section 10.05) and the Standby Rate (Section 11.01). I will address the specific restructuring items below.

Q. IS OTP ADDING ANY ADDITIONAL REQUIREMENTS TO THE LARGE GENERAL SERVICE RATES?

A. Yes: we are adding conditions that are intended to work in conjunction with the new 200 kW demand threshold proposed for Sections 10.02 and 10.03. As described earlier, these revisions are all intended to prevent inappropriate rate arbitrage by larger, low-load-factor customers.

Q. PLEASE DESCRIBE THE CONDITIONS BEING ADDED TO THE LARGE GENERAL SERVICE RATES.

A. OTP proposes to add the following language to both Section 10.04 and 10.05:

> The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW for more than two of the most recent 12 months. Customers on this schedule whose maximum monthly Billing Demand are less than 200 kW for less than 10 of the most recent 12 months, may take service on Section 10.02 or 10.03. If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule.

Q. PLEASE DESCRIBE YOUR BASE RATE DESIGN PROPOSAL FOR THE SECTION 10.04 LARGE GENERAL SERVICE RATE.

A. The present and proposed rate components are identified in the table below. The proposed Section 10.04 rate continues with single block seasonal demand and energy charges. These charges are based on marginal costs. Demand charges are increasing and are set 20 percent higher than marginal capacity cost. Customer charges remain unchanged, but also are higher than marginal customer-related costs. Finally, facilities charges are set at marginal costs, and the energy costs are below marginal energy costs in order to collect the remainder of the revenue requirement. The proposed rate retains the minimum demand at 80 kW, although there is an option for high-load factor customers under 80 kW to pay demand charges based on the minimum demand (80 kW) rather than their measured demand. This allows smaller customers who are unusually efficient to take advantage of a rate that better rewards their efficiency.

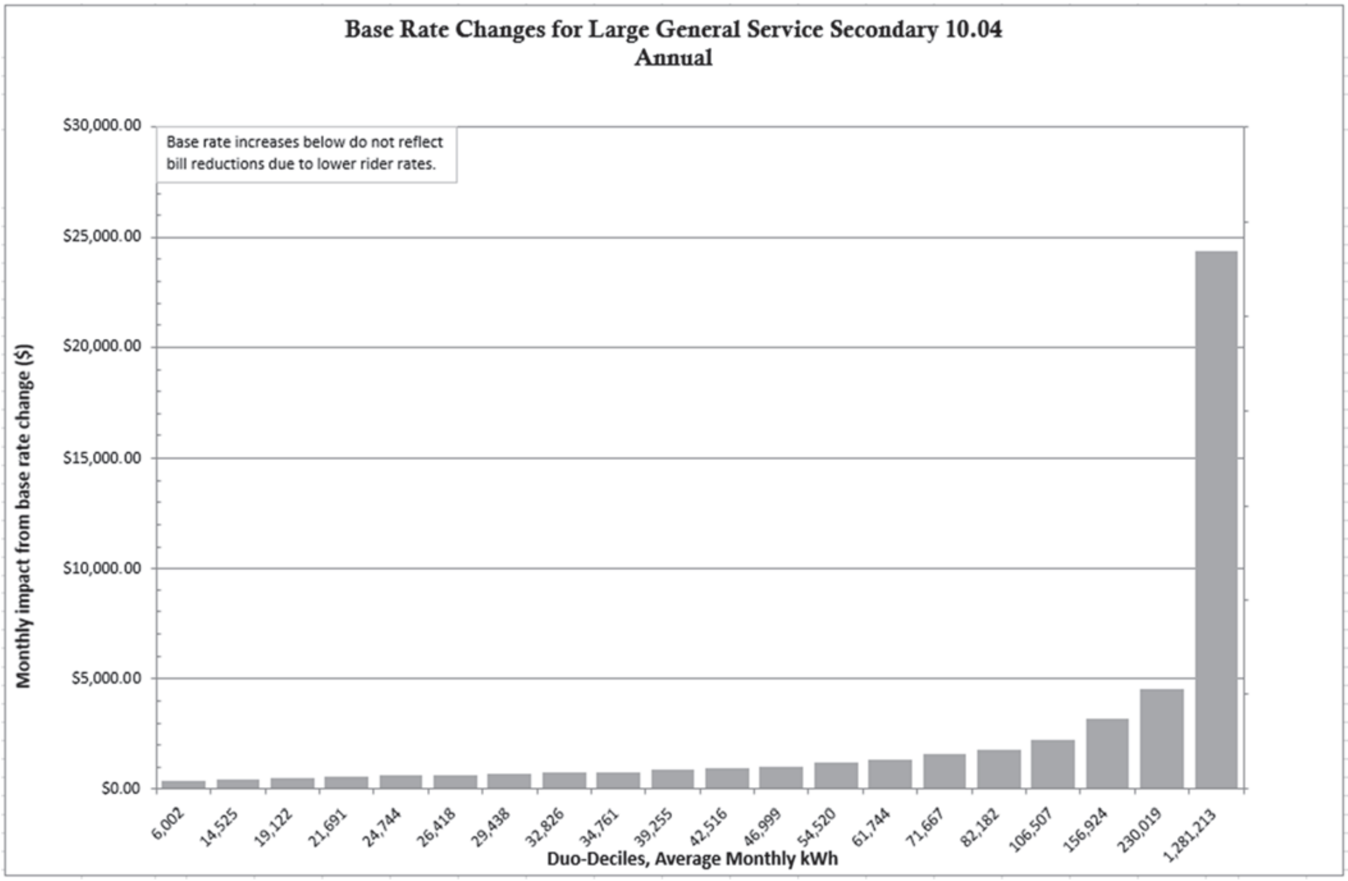
Table 9
Comparison of Current and Proposed 10.04 Large General Service Rate and Marginal

LARGE GENERAL SERVICE	Section 10.04								
	Customer Charge per month	Minimum Bill per month		Facilities Charge per annual max. kW (minimum 80 kw) per month		Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
SECONDARY 603									
Current Rate	$215.90	Cust+Fac+Demand			All Energy	$0.02286	$0.02341	$10.75	$8.54
			< 1000 kW:	$0.76					
			> 1000 kW:	$0.56					
Proposed - Secondary	$215.90	Cust+Fac+Demand			All Energy	$0.03045	$0.04042	$10.75	$13.22
			< 1000 kW:	$0.75					
			> 1000 kW:	$0.52					
Marginal Costs	$113.62		< 1000 kW:	$0.75		$0.04453	$0.05911	$8.96	$11.02
			> 1000 kW:	$0.52					
PRIMARY 602						Summer	Winter	Summer	Winter
Current Rate	$282.00	Cust+Fac+Demand		($ per kVA-Month) $0.48	All Energy	$0.02224	$0.02264	$10.35	$8.15
Proposed - Primary	$282.00	Cust+Fac+Demand		$0.52	All Energy	$0.02971	$0.03333	$10.31	$12.57
Marginal Costs	$239.31			$0.52		$0.04345	$0.04875	$8.59	$10.47
TRANSMISSION 632						Summer	Winter	Summer	Winter
Current Rate	$282.00	Cust+Fac+Demand		$0.00	All Energy	$0.02103	$0.02121	$8.85	$7.30
Proposed - Transmission	$282.00	Cust+Fac+Demand		$0.00	All Energy	$0.02901	$0.03237	$9.54	$6.68
Marginal Costs	$239.31			$0.00		$0.04242	$0.04734	$7.95	$5.57

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED 10.04 LGS RATE?

A. The base rate impacts for this class of large customers are in the range of a few hundred to a few thousand dollars. About 80 percent of the customers on the secondary rate will see an increase of about $2,000 or less per month. Due to the small number of customers, no base rate impacts will be shown for the primary voltage customers.

Figure 7



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 10.05 LARGE GENERAL SERVICE –TIME OF DAY RATE.

A. OTP's proposal for the Large General Service Time of Day (LGS TOD) rate generally continues with the current design. The present and proposed rate components are identified in the table below. The time-differentiated energy and demand charges are adjusted in a similar fashion as those discussed in the Large General Service Section 10.05 rate.

Table 10
Comparison of Current and Proposed 10.05 Large General Service Time of Day Rate and Marginal Costs

LARGE GENERAL SERVICE - TIME OF DAY			Section 10.05													
Customer #	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)		Energy Charge per kWh Summer			Winter			Demand Charge per kW Summer			Winter		
SECONDARY					PK 611	MP 615	OP 613	PK 611	MP 615	OP 613	PK 611	MP 615	OP 613	PK 611	MP 615	OP 613
Current Rate	$215.90	Cust. + Facilities	$0.76	< 1,000 kW	$0.03527	$0.02683	$0.01776	$0.03090	$0.02753	$0.01925	$7.31	$3.44	$0.00	$5.29	$3.25	$0.00
			$0.57	>=1,000 kW												
Rate 1	$215.90	Cust. + Facilities	$0.76	< 1,000 kW	**$0.04847**	**$0.03948**	**$0.02576**	**$0.04348**	**$0.03964**	**$0.03411**	**$7.67**	**$3.08**	**$0.00**	**$5.81**	**$7.41**	**$0.00**
			$0.57	>=1,000 kW												
Marginal Costs	$108.29		$0.75 $0.65		$0.06589	$0.05368	$0.03502	$0.05911	$0.05389	$0.04637	$6.40	$2.01	$0.56	$4.84	$4.28	$1.90
PRIMARY					PK 610	MP 614	OP 612	PK 610	MP 614	OP 612	PK 610	MP 614	OP 612	PK 610	MP 614	OP 612
Current Rate	$282.00	Cust. + Facilities	$0.48		$0.03422	$0.02612	$0.01738	$0.02981	$0.02665	$0.01871	$7.05	$3.29	$0.00	$5.03	$3.12	$0.00
Rate 1	$282.00	Cust. + Facilities	$0.48		**$0.04717**	**$0.03852**	**$0.02517**	**$0.04207**	**$0.03844**	**$0.03312**	**$7.36**	**$2.96**	**$0.00**	**$5.53**	**$7.04**	**$0.00**
Marginal Costs	$239.31		$0.65		$0.06413	$0.05237	$0.03422	$0.05719	$0.05226	$0.04503	$6.13	$1.93	$0.54	$4.61	$4.06	$1.81
TRANSMISSION					PK 639	MP 637	OP 640	PK 639	MP 637	OP 640	PK 639	MP 637	OP 640	PK 639	MP 637	OP 640
Current Rate	$282.00	Cust. + Facilities	$0.00		$0.03213	$0.02465	$0.01653	$0.02775	$0.02494	$0.01760	$6.11	$2.74	$0.00	$4.58	$2.72	$0.00
Rate 1	$282.00	Cust. + Facilities	$0.00		**$0.04600**	**$0.03760**	**$0.02460**	**$0.04076**	**$0.03732**	**$0.03219**	**$6.80**	**$2.74**	**$0.00**	**$2.54**	**$4.14**	**$0.00**
Marginal Costs	$239.31		$0.00		$0.06253	$0.05112	$0.03344	$0.0554	$0.0507	$0.0438	$5.67	$1.78	$0.50	$2.12	$2.50	$0.95

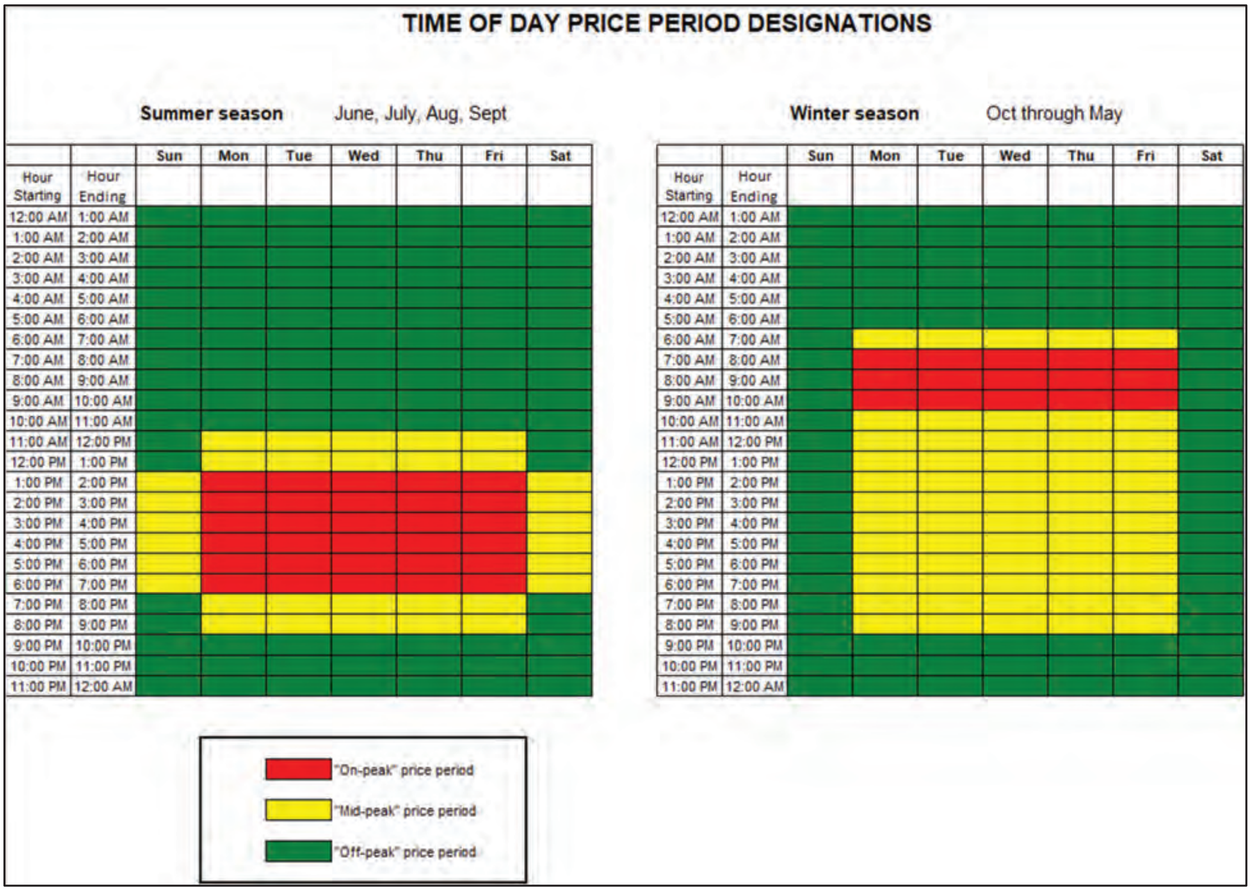
Q. HAVE YOU INCLUDED A BILL IMPACTS ANALYSIS FOR THE 10.05 LARGE GENERAL SERVICE – TIME OF DAY RATE?

A. No. There is currently one customer taking service on this rate. Individualized bill analysis would compromise the privacy of this customer.

Q. ARE YOU PROPOSING TO CHANGE THE TIME OF USE PERIODS FOR THIS RATE?

A. Yes. The changes to the time of use periods are based on the results of the 2024 Marginal Cost Study. The new periods include decreased on-peak hours and increased off-peak and mid-peak (was shoulder) hours. The chart below shows a graphical representation of the new period definitions. Specific period definitions are included in the proposed rate schedule, which are part of Volume 2C.

Figure 8



Q. PLEASE PROVIDE A SUMMARY OF CHANGES TO THE TIME OF USE PERIODS FOR THE SECTION 10.05 RATE.

A. The changes improve the correlation of expected market prices and the proposed time of day periods. Specifically:

- Summer weekday: added an additional off-peak hour (was mid-peak, formerly known as shoulder) from 9pm-10pm
- Summer weekend: added additional off-peak hours (were mid-peak) from 11am-1pm, 7pm-10pm
- Winter weekday:
    - added additional mid-peak, (was on peak) from 10am-11am
    - added additional off-peak (was mid-peak) from 9pm-10pm
- Winter weekend: removed all shoulder, now is all off-peak (used to be 4 mid-peak hours).

Q. IS OTP PROPOSING A TRIAL PERIOD FOR THE SECTION 10.05 LARGE GENERAL SERVICE – TIME OF DAY RATE?

A. Yes. This is another example of our rates restructuring efforts. The proposal offers interested customers a 3-month trial period on this rate. This restructuring proposal is based on one of the five restructuring efforts: Customer-centric/flexibility. The proposed language is included in our proposed rates, and for convenience, shown below:

<u>Proposed Optional Trial Service: Large General Service Time of Day</u>

- Customers may elect Time of Day service for a trial period of three months.
- If a Customer chooses to return to non-time of day service after the trial period, the Customer will pay a charge of $60.00 for removal of time of day metering equipment.
- If a Customer chooses to change from this schedule after the three-month trial period, the customer must notify the Company within 15 days after the trial period ends. Otherwise, the Customer will remain on this schedule for the minimum of one year as described in the General Rules and Regulations Section 1.02.
- The Company will remove the time of day metering equipment and switch the customer to a different applicable rate within 45 days of receipt of written notice of termination of the trial period.

Q. ARE THERE ANY OTHER RESTRUCTURING CONSIDERATIONS FOR YOUR LARGE GENERAL SERVICE RATE DESIGNS NOT INCLUDED IN YOUR TESTIMONY?

A. Yes. Due to the number of large customers with high load factors, OTP continues to examine the potential for a high-load-factor rate design class in the future.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 11.01 STANDBY RATE.

A. OTP proposes to continue with the current design, based on marginal costs, with updated rate levels. The proposed Standby Service rate provides three services under one rate schedule. These services are Backup, Scheduled Maintenance, and Supplemental Service:

- Backup Services is the energy and demand supplied by the utility during unscheduled outages of a Customer's generator.
- Scheduled Maintenance Service is the energy and demand supplied by the utility during scheduled outages of a Customer's generator.
- Supplemental Service is the energy and demand supplied by the utility in addition to the capability of the on-site generator.

Table 11
Comparison of Current and Proposed Standby Service
Rate and Marginal Costs

Standby Service		11.01													
	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh						Demand Charge per kW					
				Summer			Winter			Summer			Winter		
				PK	SH	OP	PK	SH	OP	PK	SH	OP	PK	SH	OP
SECONDARY															
Current Rate	$242.24	Cust. + Facilities	$0.55000	0.05351	0.03507	0.00950	0.04074	0.03557	0.01596	$0.54794	$0.00	$0.00	$0.43005	$0.00	$0.00
		Reserve Charge per kW		$0.6564			$0.2235			$0.5479			$0.4301	$ per kW per day	
Proposed	$105.33	Cust+Reservation+Facilities	$1.0260	$0.03462	$0.02935	$0.01995	$0.03540	$0.03313	$0.02539	$0.6577	$0.00	$0.00	$0.4117	$0.00	$0.00
		Reserve Charge per kW		$1.7535			$0.0400			$0.6577			$0.4117	$ per kW per day	
Marginal Costs	$105.33		$1.03	$0.03385	$0.02870	$0.01950	$0.03462	$0.03240	$0.02483	$0.66	$0.00	$0.00	$0.41	$0.00	$0.00
PRIMARY															
Current Rate	$304.33	Cust. + Facilities	$0.45000	$0.05063	$0.03305	$0.00851	$0.03784	$0.03307	$0.01443	$0.5246	$0.00	$0.00	$0.4080	$0.00	$0.00
		Reserve Charge per kW		$0.1604			$0.0510			$0.5246			$0.4080	$ per kW per day	
Proposed	$437.30	Cust+Reservation+Facilities	$0.6915	$0.03370	$0.02859	$0.01951	$0.03425	$0.03212	$0.02465	$0.6838	$0.00	$0.00	$0.7003	$0.00	$0.00
		Reserve Charge per kW		$1.6786			$0.0380			$0.6297			$0.3904	$ per kW per day	
Marginal Costs	$437.30		$0.69	$0.03295	$0.0280	$0.01908	$0.03350	$0.03141	$0.02411	$0.63	$0.00	$0.00	$0.39	$0.00	$0.00
TRANSMISSION															
Current Rate	$304.33	Cust. + Facilities	$0.00	$0.04604	$0.02982	$0.00690	$0.03333	$0.02916	$0.01202	$0.6367	$0.00	$0.00	$0.6433	$0.00	$0.00
		Reserve Charge per kW		$0.5842			$0.1990			$0.4881			$0.3742	$ per kW per day	
Proposed	$437.30	Cust+Reservation+Facilities	$0.00	$0.03286	$0.02790	$0.01911	$0.03323	$0.03121	$0.02399	$0.4881	$0.00	$0.00	$0.3742	$0.00	$0.00
		Reserve Charge per kW		$1.5607			$0.0349			$0.5858			$0.3578	$ per kW per day	
Marginal Costs	$437.30		N/A	$0.0321	$0.02729	$0.01869	$0.0325	$0.0305	$0.0235	$0.59	$0.00	$0.00	$0.36	$0.00	$0.00

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED 11.01 STANDBY SERVICE RATES?

A. OTP has one North Dakota customer currently taking Standby Service. Again, individualized bill analysis would compromise the privacy of the customer.

Q. IS OTP PROPOSING ANY OTHER REVISIONS TO THE SECTION 11.01 RATE?

A. Yes. OTP is proposing minor language restructuring improvements to the Standby rate schedule, including:

- Included Supplemental Demand charges in the rate versus referencing the Large General Service Time of Day (10.05) rate schedule;
- Added language to ensure contracted backup demands are kept current and both company and customer are engaged in changes occurring with the services provided; and
- Added additional definitions.

In Section VII, below, I also address changes related to Standby service regarding partial requirements customers.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 10.06 SUPER LARGE GENERAL SERVICE RATE.

A. OTP's Super Large General Service (SLGS) rate offering primarily is targeted at attracting high-load-factor large commercial customers to OTP's service territory. Qualifying customers have access to individual contract pricing based on OTP's marginal cost of service, though that pricing must ensure net benefits to other customers. OTP currently has one customer, APLD Hosting, LLC, a wholly owned affiliate of Applied Digital, Inc. ("Applied") (formerly known as Applied Blockchain), taking service under the SLGS tariff.[4] We are proposing to update Applied's individual contract pricing for the reasons discussed by OTP witness Mr. Bruce G. Gerhardson in his Direct Testimony. Given the proprietary nature of Applied's pricing, the updated rates are being provided directly to Applied, though the resulting revenue change can be identified in Schedule E-2 of Volume 3, Supporting Information.

Q. HOW DID YOU DEVELOP THE UPDATED INDIVIDUALIZED PRICING FOR THE CUSTOMER TAKING SERVICE UNDER THE SLGS RATE?

A. Contract pricing offered under the SLGS tariff is customized for the individual customer based on their specific load characteristics and investment needed to serve the customer. SLGS customers pay rates based on marginal costs rather than embedded costs. We developed individualized pricing for Applied based on these principles and that pricing was approved by the Commission in Case No. PU-21-366.

The revised pricing for Applied continues to adhere to the principles of the SLGS tariff in that it reflects Applied's specific load characteristics and investment needed to serve the customer. It also reflects updated marginal costs, as measured in the 2024 Marginal Cost Study. Finally, the revised pricing maintains approximately the same allocation of net benefits between Applied and other customers that was present in Case No. PU-21-366.

[4] *See* Case Nos. PU-21-364, 21-365, 21-366.

E. Irrigation Class

Q. WHAT RATE SCHEDULES ARE IN THE IRRIGATION SERVICE CLASS?

A. There is only one rate schedule in the Irrigation Class, the Irrigation Service (Section 11.02). However, there are two service options offered under this rate.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.02 IRRIGATION SERVICE RATE.

A. The present and proposed rate components are identified in the table below.

Table 12
Comparison of Current and Proposed 11.02 Irrigation Service Option 1 & 2 Rate and Marginal Costs

Section 11.02

Irrigation Option #1 | Irrigation Option #2

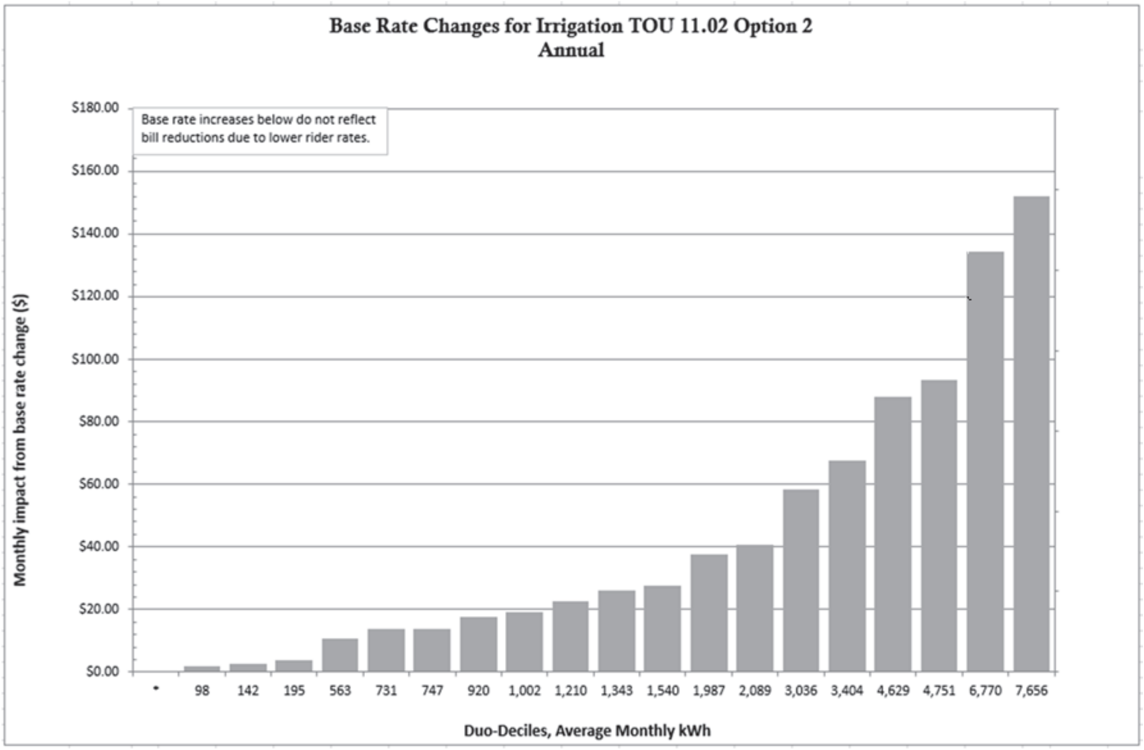
SECONDARY	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per HP Summer	Demand Charge per HP Winter
Current Rate OPTION 1	$24.30	Cust +Fac	Customer Specific	$0.04533	$0.02633	N/A	N/A
Proposed Rate	$24.30	Customer + Facilities	Customer Specific	$0.06073	$0.04173	N/A	N/A
Marginal Costs	$35.62			$0.05677	$0.08444	N/A	N/A

OPTION 2	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Summer Declared Peak (per kWh)	Summer Intermediate (per kWh)	Summer Off-Peak (per kWh)	Winter Declared Peak (per kWh)	Winter Intermediate (per kWh)	Winter Off-Peak (per kWh)	Summer Declared Peak (per kW)	Summer Intermediate (per kW)	Summer Off-Peak (per kW)	Winter Declared Peak (per kW)	Winter Interme diate (per kW)	Winter Off-Peak (per kW)
Current Rate	$24.30	Cust +Fac	Customer Specific	$0.17685	$0.03274	$0.01420	$0.12867	$0.03050	$0.01457	N/A	N/A	N/A	N/A	N/A	N/A
Proposed Rate	$24.30	Cust +Fac	Customer Specific	$0.18683	$0.05653	$0.03085	$0.22632	$0.05960	$0.04348	N/A	N/A	N/A	N/A	N/A	N/A
Marginal Costs	$35.62			$0.18683	$0.06648	$0.03628	$0.22632	$0.07009	$0.05113						

Q. WHAT ARE THE BASE RATE IMPACTS FROM YOUR PROPOSED IRRIGATION SERVICE RATE (SECTION 11.02)?

A. The base rate impacts for Option 1 (non-time of use) are not provided in order to protect the privacy of the customers (fewer than 20) on this rate option Option 2 is a time of use rate which allows irrigation customers to participate in the same manner as described in Section 10.03 rate. The base rate impacts for this rate result in 75 percent of the customers with impacts less than $60. Like the discussion in Section 10.03, all customer impacts can vary depending upon the mid-peak and off-peak usage of the customers. Because the impacts represented in the graph are determined based on customers' usage patterns and because the purpose of time of use rates such as this one are to incentivize customer usage based on the price signals being sent by the particular rate design, it is reasonable to expect that actual customer impacts may be less than represented here by responding to the price signals incorporated into the rate.

Figure 9



Q. IS ONE OF YOUR RESTRUCTURING PROPOSALS CHANGING HOW NEW IRRIGATION CUSTOMERS PAY FOR THEIR UNIQUE FACILITIES?

A. Yes. I will provide further details of the special facilities charge proposal later in my testimony.

F. Outdoor Lighting Class

Q. WHAT RATE SCHEDULES ARE IN THE LIGHTING SERVICE CLASS?

A. There are three rates in the Outdoor Lighting Class: Outdoor Lighting – Energy Only (Section 11.03), Outdoor Lighting (Section 11.04), and LED Street and Area Lighting – Dusk to Dawn (Section 11.07).

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 11.03 OUTDOOR LIGHTING-ENERGY ONLY RATE (RATE CODES 748 AND 749).

A. OTP's proposal is shown in the table below.

Table 13
Comparison of Current and Proposed 11.03 Outdoor Lighting Energy-Only Rate and Marginal Costs

ND Energy Only Lighting - 11.03	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh
Metered				
Current Rate	$2.00	$2.00	$0.00	0.06681
Proposed Rate	$2.00	$2.00	$0.00	0.07821
Marginal Costs	$3.59		$0.00	$0.04934
Non-Metered				
Current Rate	Connected kW x	$22.83	Current rate * 4100 hrs in year / 12 months	
Proposed Rate	Connected kW x	$23.42	Current rate * 4100 hrs in year / 12 months	

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED 11.03 OUTDOOR LIGHTING-ENERGY ONLY RATE?

A. The overall base rate impacts for the rate are 2.61 percent.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.04 OUTDOOR LIGHTING RATE.

A. The 11.04 Outdoor Lighting Rate proposal continues to operate as a closed rate since these are non-LED services. OTP is continuing its LED change-out program and is scheduled to complete all LED installations by end of 2028. The table below contains expected current base and proposed base revenues for non-LED fixtures. Note that these amounts do not reflect bill reductions due to lower rider rates.

Table 14

ND Energy Only Lighting - 11.04		
	STREET, AREA, and FLOOD LIGHTING	
Current Revenue	Proposed Revenue	Increase
$ 900,453	$ 950,046	$ 49,593

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 11.04 OUTDOOR LIGHTING RATE?

A. The base rate impacts for each current lighting fixture are the same, 5.51 percent (i.e., different than overall revenue as we have different light fixture types and quantities).

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 11.07 OUTDOOR LIGHTING RATE?

A. The base rate impacts for each closed and current lighting fixture are the same, 0.92 percent (i.e., different than overall revenue as we have different light fixture types and quantities). Note that these amounts do not reflect bill reductions due to lower rider rates.

Table 15

ND LED STREET and AREA LIGHTING - DUSK TO DAWN 11.07		
	STREET, AREA, and FLOOD LIGHTING	
Current Revenue	Proposed Revenue	Increase
1,558,539	1,572,920	$14,866

G. Other Public Authority Service Class

Q. WHAT RATE SCHEDULES ARE IN THE OTHER PUBLIC AUTHORITY SERVICE CLASS?

A. There are two rates in the Other Public Authority Class: Municipal Pumping Service (Section 11.05) and Civil Defense – Fire Siren Service (Section 11.06).

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE MUNICIPAL PUMPING SERVICE.

A. The present and proposed rate components are identified in the table below.

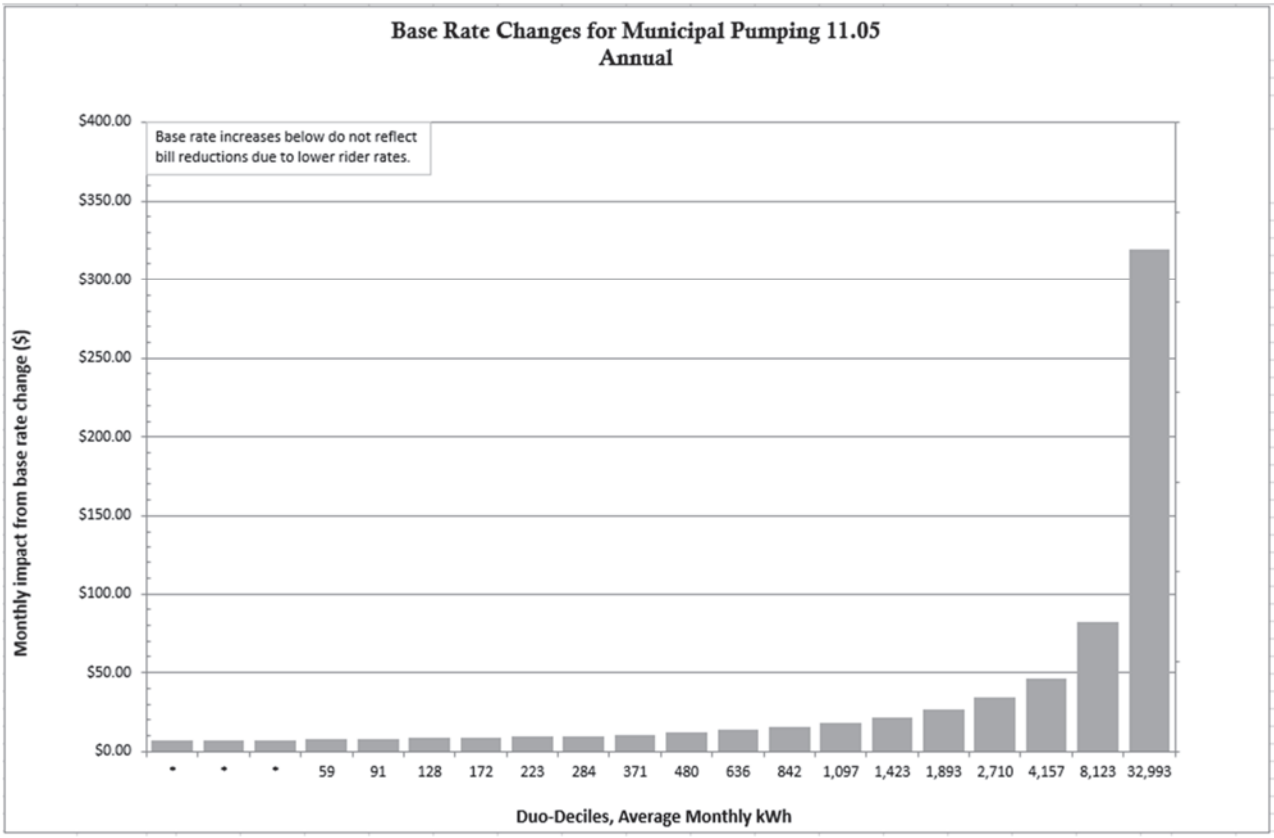
Table 16
Current and Recommended 11.05 Municipal Pumping
Rates and Marginal Costs

Municipal Pumping	Section 11.05						
Comparison of Current Rate, Recommended Rate and Marginal Cost Municipal Pumping							
		Customer $ per month	Minimum Bill $ per month		Facilities Charge $ per month	Summer $ per kWh	Winter per month
Current Rate	Secondary	$26.50	Cust + Fac	per kW	$0.65	$0.04599	$0.03111
	Primary	$26.50	Cust + Fac	per kW	$0.65	$0.04432	$0.02981
Proposed Rate	Secondary	$33.45	Cust + Fac	per KW	**$2.12**	$0.04209	$0.04778
	Primary	$33.45	Cust + Fac	per KW	**$1.42**	$0.04091	$0.04679
Marginal Costs		$33.45		Secondary	$2.12		
				Primary	$1.42		
					Energy & Demand		
All Season				Secondary	$0.05677	$0.06444	
				Primary	$0.05518	$0.06311	

Q. WHAT ARE THE BASE RATE IMPACTS OF YOUR RECOMMENDED SECTION 11.05 MUNICIPAL PUMPING RATE?

A. Base rate impacts vary, as the consumption levels of customers vary significantly under this rate. About 90 percent (18 duo-deciles) of customers have base rate impacts of less than $50.00 per month.

Figure 10



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 11.06 CIVIL DEFENSE-FIRE SIREN SERVICE RATE.

A. The proposed Civil Defense-Fire Siren Rate components are shown below.

Table 17
Current and Recommended 11.06 Civil Defense-Fire Sire Service Rate and Marginal Cost

Section 11.06 ND Civil Defense Fire Sirens				
SECONDARY	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Charge per HP
Current Rate	$1.00	Customer Charge	$0.00	$0.53193
Proposed Rate	$1.22	Customer Charge	$0.00	$0.71789
Marginal Costs	$0.30			$0.04687 $/kWh

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED CIVIL DEFENSE-FIRE SIREN SERVICE RATE SCHEDULE?

A. The base rate impacts are presented in a simple monthly bill comparison in below. The greatest monthly base rate bill dollar impact is $5.77 per month. Note that these amounts do not reflect bill reductions due to lower rider rates.

Table 18
Monthly Base Bill Impacts – 11.06 Civil Defense-Fire Siren Service

Siren HP	Monthly Impacts			
	Current Bill	Proposed Bill	Difference	% Change
12.5	$ 6.59	$ 10.19	$ 3.60	55%
1	$ 1.65	$ 1.94	$ 0.29	17%
1.5	$ 1.86	$ 2.30	$ 0.43	23%
10	$ 5.52	$ 8.40	$ 2.88	52%
2	$ 2.08	$ 2.66	$ 0.58	28%
2.5	$ 2.29	$ 3.01	$ 0.72	31%
20	$ 9.81	$ 15.58	$ 5.77	59%
3	$ 2.51	$ 3.37	$ 0.86	34%
3.5	$ 2.72	$ 3.73	$ 1.01	37%
4.5	$ 3.15	$ 4.45	$ 1.30	41%
5	$ 3.37	$ 4.81	$ 1.44	43%
6.5	$ 4.01	$ 5.89	$ 1.87	47%
7	$ 4.23	$ 6.25	$ 2.02	48%
7.5	$ 4.44	$ 6.60	$ 2.16	49%

H. Controlled Service Deferred Load Class

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE DEFERRED LOAD SERVICE CLASS?

A. There are two rates in the Controlled Service Deferred Load Class, the Water Heating – Controlled Service Rider (Section 14.01) and Controlled Service – Deferred Load Rider (Section 14.06).

Q. ARE ANY PROPOSED RATES IN THIS CLASS A PART OF YOUR RATE RESTRUCTURING INITIATIVE?

A. Yes. Both rates were placed into one customer class to create alignment of rate classes within the appropriate customer class. They are better aligned in one customer class because of the nature of their operations during control periods and similarities in their load profiles. This also results in improved cost allocations.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.01 WATER HEATING-CONTROLLED SERVICE RIDER.

A. The proposal for the Metered Water Heating Control Service shown in the table below increases the customer charge to approximately 78 percent of marginal cost, retains the current method for calculating the minimum bill, and sets both seasonal energy charges at levels necessary to match rate revenues to the rate's revenue requirement. A facilities charge was added to collect a portion (under 10 percent) of the marginal facilities costs. The marginal costs of providing service to customers on this rate are lower than the marginal cost for standard rates because OTP controls the water heaters during high-cost periods.

Table 19
Current and Proposed 14.01 Water Heating-Controlled Service Rider
Rate and Marginal Costs

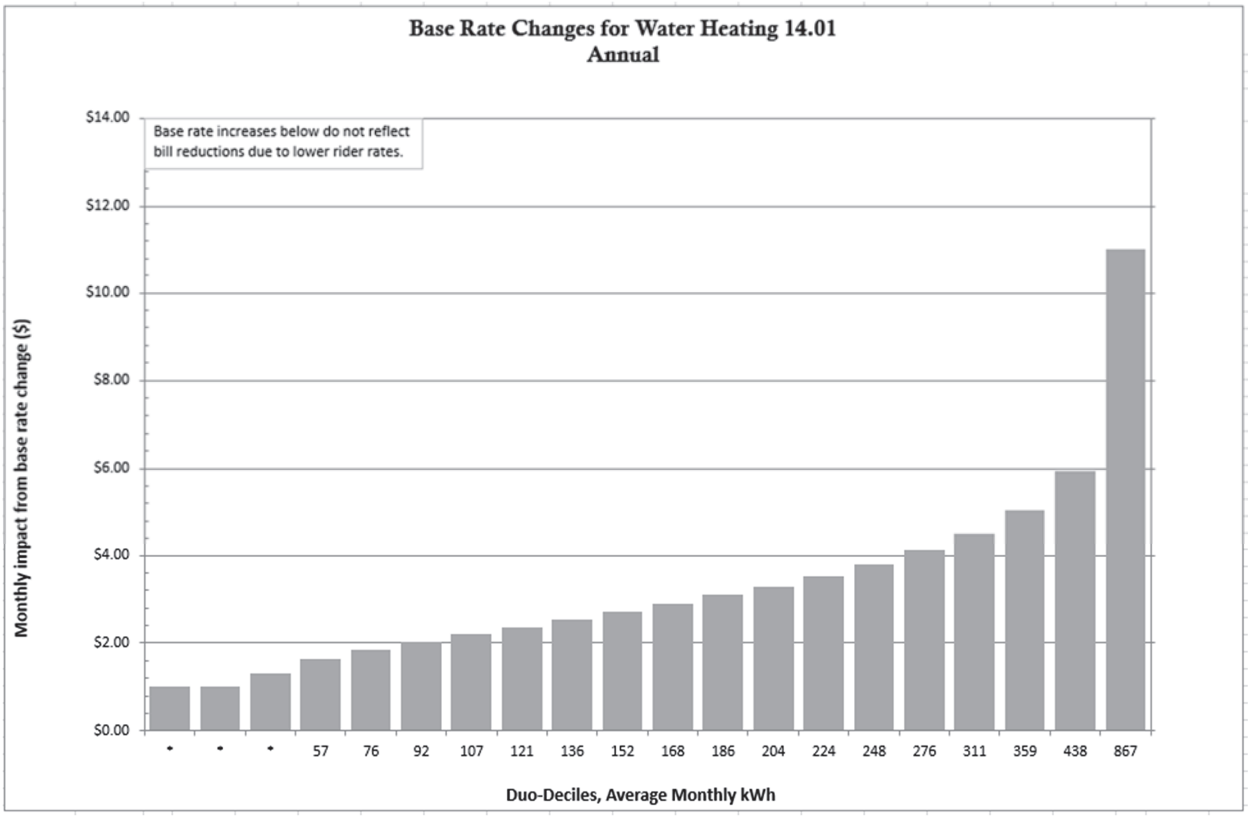
Water Heating Control (Off-Peak)		Section 14.01				
		Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter
Current	Customer Charge, Seasonal Energy	$4.00	Cust. + Facilities	$2.00	$0.03078	$0.02661
Proposed Rate	Customer Charge, Seasonal Energy	$5.00	Cust. + Facilities	$2.00	$0.03813	$0.03950
Marginal Costs		$6.45		$24.87	$0.05825	$0.06035

The Water Heating Control Service Credit (Rate Code 192) is essentially a direct load-control program similar to direct load-control of central air conditioners. Under the rate, in exchange for allowing OTP to interrupt the water heating service during high-cost periods, OTP compensates the customer in the form of a bill credit. The credit continues at $8.00 per month.

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED 14.01 WATER HEATING-CONTROLLED SERVICE RIDER?

A. Under OTP's proposal, shown in the figure below, 95 percent of Metered Water Heating Control Service customers see a monthly increase of about $6.00. The base rate impacts for the Water Heating Control Service Credit (Rate Code 192), not shown in the figure below, will continue to reduce the customers' standard firm service total bill by $8.00 per month. The impact of the $8.00 credit is reflected in the duo-deciles for the appropriate firm service rates (*e.g*. Residential Service, Figure 1, above).

Figure 11



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.06 CONTROLLED SERVICE – DEFERRED LOAD RIDER

A. The proposal for the Controlled Service – Deferred rate is shown in the table below. It increases the customer charge to approximately 60 percent of marginal cost, retains the current method for calculating the minimum bill, and sets both seasonal energy charges at levels necessary to match rate revenues to the rate's revenue requirement. The facilities charge remains unchanged. The marginal costs of providing service to customers on this rate are similar to the water heating marginal costs.

Table 20

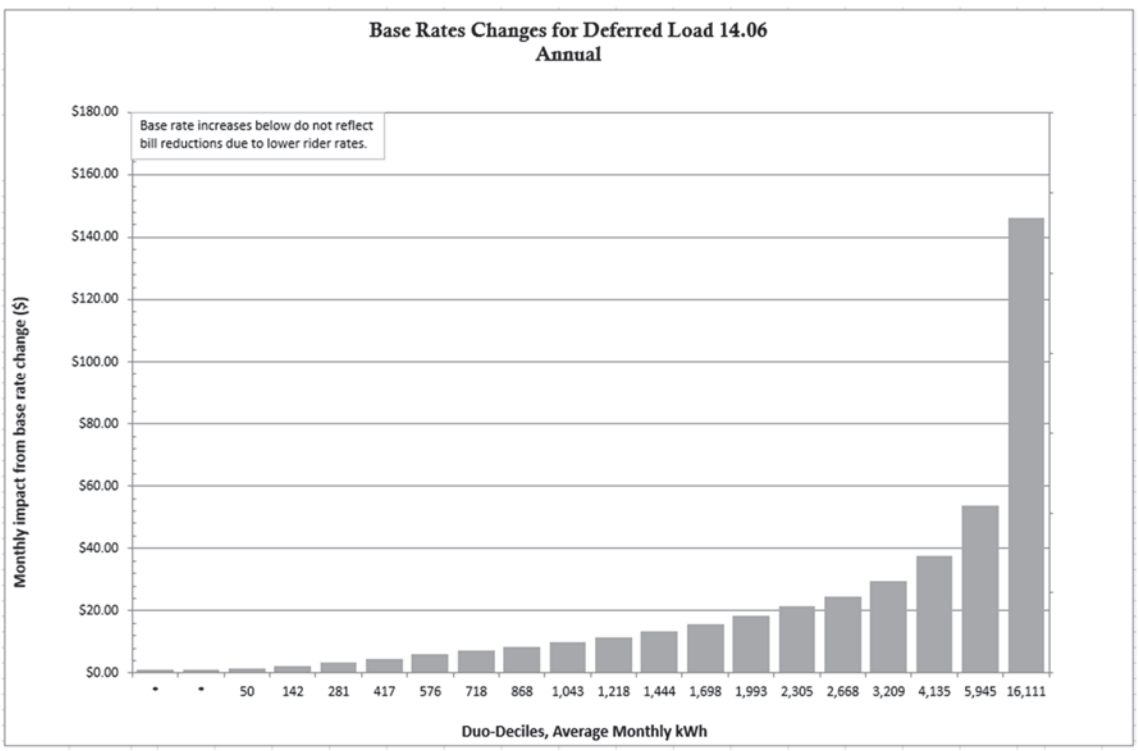
Current and Proposed 14.06 Controlled Service – Deferred Load
Rate and Marginal Costs

Controlled Service - Deferred Load	Section 14.06						
	Customer Charge per month	Monthly Minimum Bill per month		Facilities Charge per month	Energy Charge per kWh	Summer	Winter
Current Deferred Load Rate	$8.80	Customer Charge+Facilities	Flat charge per month	$11.60	All kWhs	$0.02602	$0.02371
					Penalty kwhs	$0.35916	$0.16537
Proposed Rate	$10.00	Customer Charge+Facilities	Flat charge per month	$11.60	All kWhs	$0.04346	$0.03190
					Penalty kwhs	$0.17726	$0.18221
Marginal Costs	$16.76		Urban	$14.93		$0.05486	$0.04026
			Rural	$49.75		$0.17726	$0.18221

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED 14.06 DEFERRED-CONTROLLED SERVICE RIDER?

A. Under OTP's proposal, shown in the figure below, 80 percent of the customers will see less than a $22 per month increase. The average customer in this rate class uses more than 5 times the amount of energy as compared to the Water Heater rate class.

Figure 12



I. Controlled Service – Interruptible Class

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE CONTROLLED SERVICE - INTERRUPTIBLE CLASS?

A. There are two current rates in the Interruptible Service Class: Controlled Service – Interruptible Load CT Metering (Section 14.04) Rider and Controlled Service – Interruptible Load Self-Contained Metering (Section 14.05) Rider.

Q. ARE ANY PROPOSED RATES IN THIS CLASS A PART OF YOUR RATE RESTRUCTURING INITIATIVE?

A. Yes. We are proposing to combine Schedules 14.04 and 14.05 into a single rate schedule for customer convenience and simplicity. Therefore, Section 14.05 is proposed to be removed as described in the Matrix of Tariff Changes included as Exhibit___(DGP-1), Schedule 4.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.04 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (CT METERING) RIDER, OPTION 1.

A. The proposed Controlled Service – Option 1 Rider, shown in the table below, includes increases to customer and facilities charges. The facilities charge is set at 100 percent of marginal costs. The energy rate is at about 95 percent of marginal costs. The penalty rate for energy consumed during control periods is based on the total marginal cost over a year and separated into summer and winter seasons. The penalty rate per kWh has been calculated based on the hourly marginal costs during periods usage would be controlled. Fundamentally, the penalty rate charges customers for unauthorized use during control periods.

Table 21
Current and Proposed
Option 1 Controlled Service-Interruptible Load (CT Metering) Rider 14.04
Rate and Marginal Costs

Large Dual Fuel - Option 1	Section 14.04					
Controlled Service - Interruptible - (assumes all customers have CT metering)						
	Customer Charge per month	**Monthly Minimum Bill per month**	**Facilities Charge**		**Energy Charge per kWh Summer**	**Winter**
Current Rate	$20.20	Cust. + Facilities	$0.76 per kW	All kWh	$0.01064	$0.01009
				Penalty kWh	$0.41350	$0.14322
Proposed Rate	$20.20	Cust. + Facilities	$2.12 per kW	All kWh	$0.01388	$0.01203
				Penalty kWh	$0.18412	$0.20847
Marginal Costs	$16.76	<300 kW	$2.12	All kWh	$0.01462	$0.01268
		>=300 kW	$2.12	Penalty kWh	$0.18412	$0.20847

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.04 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (CT METERING) RIDER, OPTION 2.

A. As shown in the table below, the facilities charge is set at 100 percent of marginal costs, while the energy rate is at about 95 percent of marginal costs. The penalty rate described above in reference to Option 1 also applies to Option 2 for unauthorized use during control periods.

Table 22
Current and Proposed
Option 2 Controlled Service-Interruptible Load (CT Metering) Rider
Section 14.04
Rate and Marginal Costs

Large Dual Fuel - Option 2 | Section 14.04

Controlled Service-Interruptible (assumes all customers have CT metering)

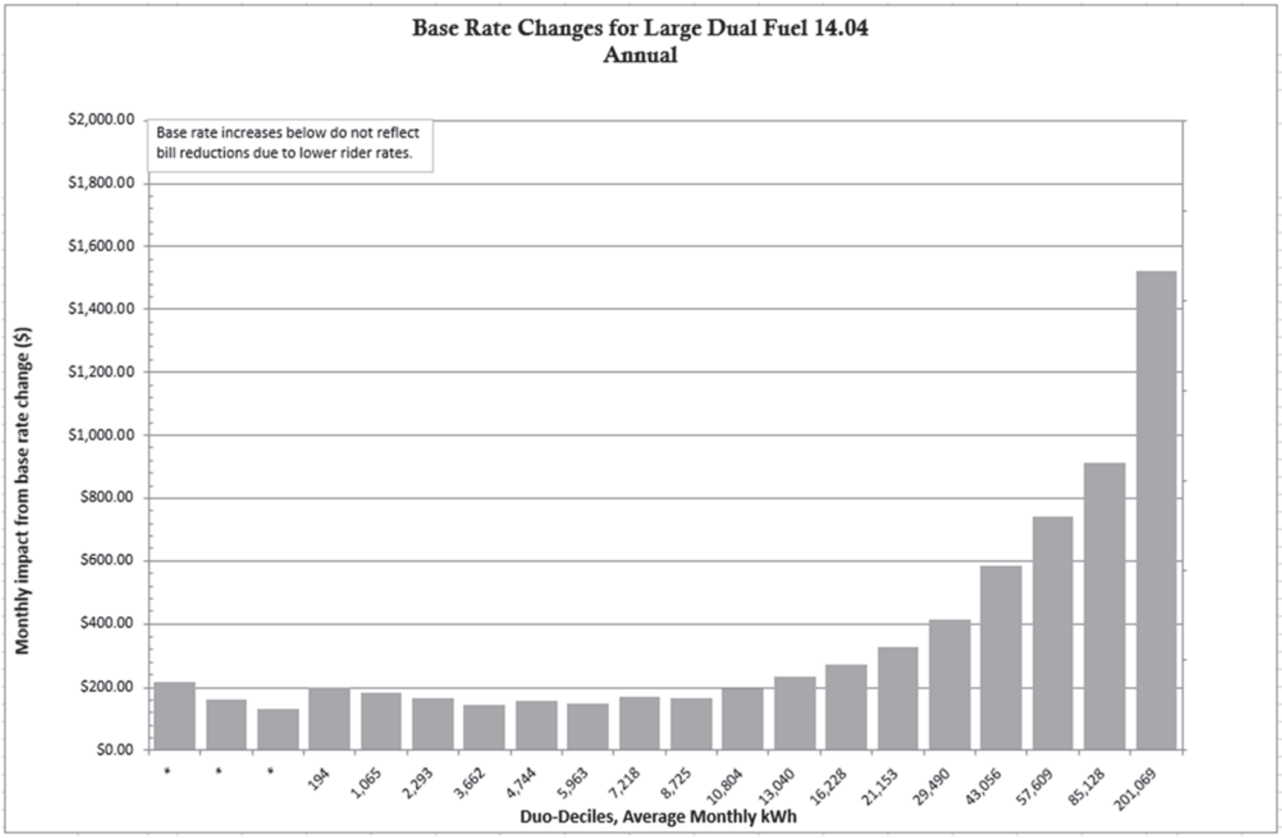
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
CURRENT RATE OPTION 2							
Secondary Seasonal Energy, kW Facilities All kWh	$20.20	Customer + Facilities charge per kW	($ per Month) $0.76	$0.01064	$0.01009	$11.30	$8.49
SECONDARY							
Proposed Rate	$20.20	Customer + Facilities charge per kW	per annual max. kW per month $2.12	$0.01388	$0.01203	$10.75	$13.22
Marginal Costs	$16.76	<300 kW >=300 kW	$2.12 $1.42	$0.01462 (Plus 5% firm energy charge)	$0.01268	$ 8.96	$ 11.02

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 14.04 CONTROLLED INTERRUPTIBLE LOAD (CT METERING) RIDER – OPTIONS 1 AND 2?

A. As shown in the figure below, the proposed rate for Option 1 shows 65 percent of the customers with average annual monthly increases around $200.

The proposed rate for Option 2 shows a rate class increase of 79 percent. Only 11 customers represent this rate class, so no duo decile is available.

Figure 13



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION14.05 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (SELF-CONTAINED METERING) RIDER.

A. OTP's proposal for this rate, as shown in the table below, maintains the customer and facilities charges, and sets both seasonal energy charges below marginal costs. The penalty for energy used during a control period is intended to deter customers from unauthorized use during control periods.

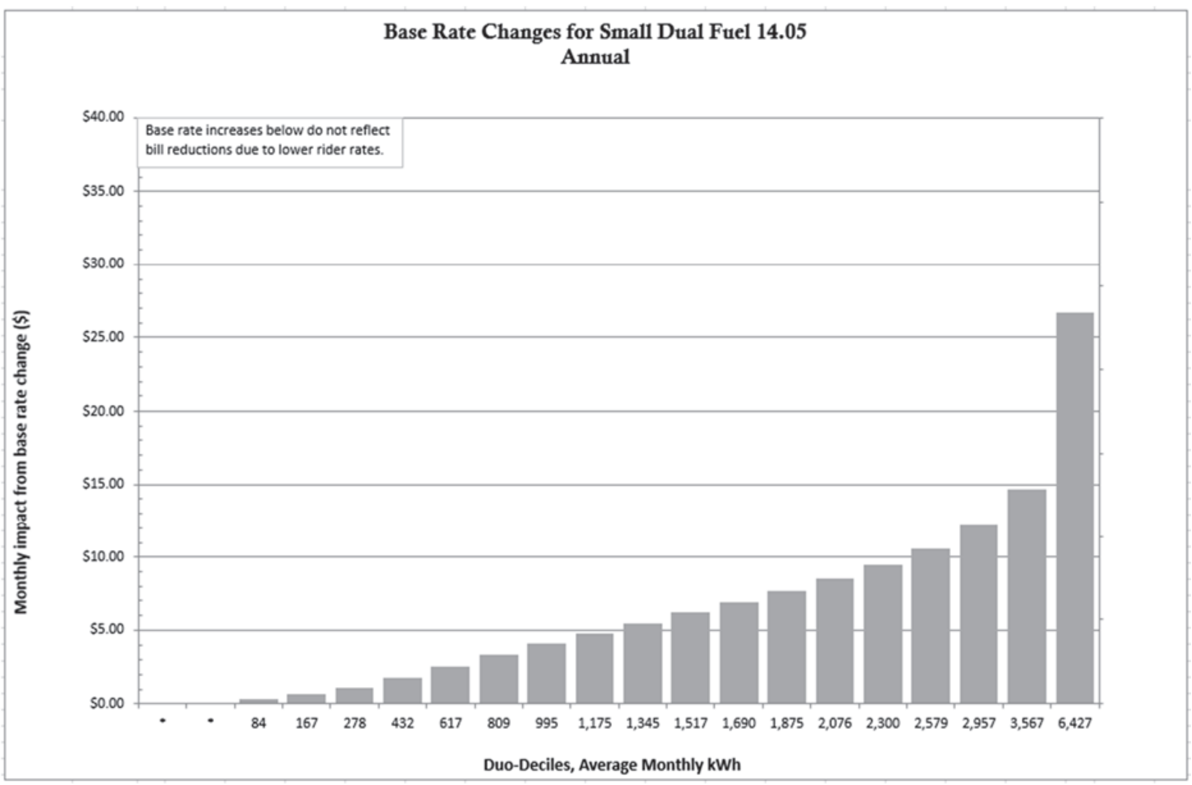
Table 23
Current and Proposed 14.05 Controlled Service-Interruptible Load (Self-Contained) Rider
Rate and Marginal Costs

Small Dual Fuel - Self Contained Metering	Section 14.05						
Controlled Service - Interruptible - SDF, Self-Contained: (assumes all customers do not have CT metering)							
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per customer per month		Energy Charge per kWh	Summer	Winter
Current Rate	$8.50	Cust. + Facilities Charge	Fixed Facilities	$11.70	All kWhs	$0.00911	$0.00850
					Penalty kWhs	$0.41350	$0.17038
Proposed Rate	$8.50	Cust. + Facilities Charge	Fixed Facilities	$11.70	All kWhs	$0.01441	$0.01249
					Penalty kWhs	$0.18412	$0.20847
Marginal Costs	$5.74		<5000 kWh in all months	$11.69	All kWhs	$0.01462	$0.01268
			> 5000 kWh in any month	$46.11	Penalty kWhs	$0.18412	$0.20847

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 14.05 CONTROLLED INTERRUPTIBLE LOAD (SELF-CONTAINED) RIDER?

A. The figure below shows about 80 percent of the class customers have annual average base rate impacts under $10.00 per month.

Figure 14



J. Controlled Service Off-Peak Class

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE SECTION 14.07 FIXED TIME OF SERVICE RIDER.

A. The proposed Fixed Time of Service rider increases customer charges for all voltages, bringing those charges closer to marginal costs. As shown in the table below, the seasonal energy charges are approximately equal to marginal costs expected in the hours when customers will receive service under the rider.

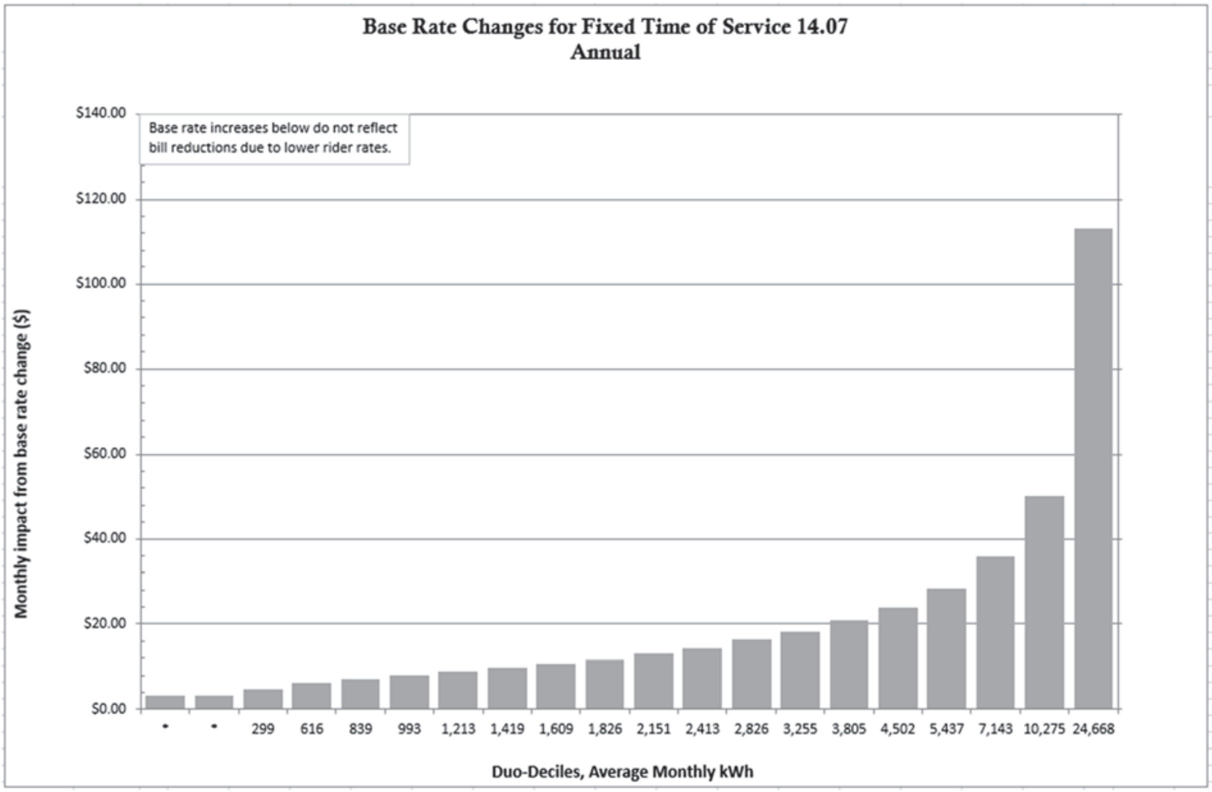
Table 24
Current and Recommended 14.07 Fixed Time of Service Rider Rate and Marginal Costs

Fixed Time of Service	Section 14.07					
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per Customer per month		Energy Charge per kWh	
Current Rate		Customer + Facilities Charge			Summer	Winter
Secondary Self-Contained Metering (301)	$6.70		$6.00		$0.01439	$0.01591
				Penalty kWh	$0.06736	$0.04602
Secondary CT Metering (302)	$6.70		$38.00		$0.01439	$0.01591
				Penalty kWh	$0.06736	$0.04602
Primary (303)	$6.70		$18.00		$0.01433	$0.01585
				Penalty kWh	$0.06736	$0.04602
Proposed Rate		Customer + Facilities Charge			Summer	Winter
Secondary Self-Contained Metering (301)	$10.00		$6.00		$0.01560	$0.02056
				Penalty kWh	$0.07432	$0.07601
Secondary CT Metering (302)	$10.00		$38.00		$0.01560	$0.02056
				Penalty kWh	$0.07432	$0.07601
Primary (303)	$10.00		$18.00		$0.01554	$0.02048
				Penalty kWh	$0.07432	$0.07601
Marginal Costs			$ per a month			
Secondary Self-Contained Metering (301)	$16.76		$21.25		$0.02588	$0.03411
				Penalty kWh	$0.07432	$0.07601
Secondary CT Metering (302)	$16.76		$106.72		$0.02588	$0.03411
				Penalty kWh	$0.07432	$0.07601
Primary (303)	$16.76		$74.77		$0.02578	$0.03398
				Penalty kWh	$0.08986	$0.09649

Q. WHAT ARE THE BASE RATE IMPACTS OF THE PROPOSED SECTION 14.07 FIXED TIME OF SERVICE RIDER?

A. The figure below shows varied base rate impacts for all customers on the proposed Fixed Time of Service Rider, most of the customers will see a bill increase of less than $20 per month.

Figure 15



Q. ARE THERE RESTRUCTURING EFFORTS IN 14.08 - AIR CONDITIONING CONTROL RIDER?

A. Yes. In addition to updating the credit payment, OTP proposes to create an extended cooling season for energy and demand control in order for the Company to control costs further and provide those benefits to participating customers.

Q. PLEASE FURTHER DESCRIBE YOUR PROPOSAL.

A. OTP proposes to increase the monthly energy curtailment from four months (June-September) to six months (May – October) and increase the compensation credit frequency from four months to five months. Total compensation will increase from $32 for four months to $40 for six months.

VI. OTHER RATE OFFERINGS

Q. ARE THERE ANY OTHER PROPOSED RATES IN YOUR RATE RESTRUCTURING INITIATIVE?

A. Yes. OTP is proposing certain revisions to Section 5.02 – Special Facilities that will impact service under two retail rate schedules: Sections 11.02 -Irrigation and 14.02 - Bulk Interruptible Service.

Q. PLEASE DESCRIBE SECTION 5.02 – SPECIAL FACILITIES.

A. Section 5.02 – Special Facilities addresses charges to customers for unique extensions and certain non-standard equipment installation to provide service to our customers.

Q. WHAT CHANGES IS OTP PROPOSING TO THE SPECIAL FACILITIES CHARGE RATES?

A. OTP is proposing to implement a rate formula to recover costs associated with equipment installations. The rate formula includes the following cost components:

1. Operations and Maintenance expense for distribution function assets, including allocated administrative and general expenses to support distribution function assets.
2. General and Common Depreciation Expenses allocated to support distribution function assets.
3. Taxes other than income taxes for distribution function assets.
4. Depreciation expense for distribution assets.
5. Income taxes
6. Return on rate base calculated with the approved capital structure.

The inputs for the formula rate template come from FERC Form 1, while the income tax inputs come from MISO Attachment O using actual results for the prior year, which aligns with the FERC Form 1 reporting.

Q. HOW IS THIS DIFFERENT THAN THE CURRENT PRACTICE?

A. The existing practice is to request rate changes only during rate cases.

Q. WHY IS THIS CHANGE BEING PROPOSED?

A. OTP files rate cases relatively infrequently. For example, this is only OTP's third rate case since 2000. Due to changing economic conditions, having an annual rate update through a formula template is more reflective of the actual costs being incurred and subsequently requested for recovery.

Q. IF APPROVED, HOW OFTEN WILL THE RATES BE UPDATED?

A. The proposed formula rates will be calculated and filed by each July 1. The calculated rates will be applied to any ESAs entered into between July 1st and June 30th of the following year. The initial rate applied to the ESA will exist for the life of the ESA. In accordance with Section 5.02, the customer has the option to prepay the Excess Expenditure amount and then in lieu of the calculated charge for Special Facilities, pay an annual fixed charge for the recovery of operations and maintenance expenses related to the Excess Expenditure amount, billed in 12 equal monthly installments. The operations and maintenance expense rate is a subcomponent of the Special Facilities charge described herein.

VII. TARIFF CHANGES OTHER THAN RATES

Q. IS OTP PROPOSING ANY CHANGES TO ITS TARIFF SCHEDULES OTHER THAN THOSE RELATING TO RATES?

A. Yes. In its last rate case, OTP made several improvements and updates to its rate book. In this case, OTP is expanding on those improvements and is making additional changes, mainly to provide clarity of service conditions and requirements for customers and OTP. Many of the changes are common to all rate schedules, while others are specific to individual rate schedules. All of the changes are reflected in the Matrix of Tariff Changes included as Exhibit___(DGP-1), Schedule 4.

Q. IS OTP MAKING ANY SUBSTANTIVE CHANGES TO ITS TARIFFS THAT GO BEYOND CLARIFICATION?

A. Yes. The most major changes relate to new challenges OTP has experienced since the last rate case. There were several changes made to address the effect partial requirements customers have on OTP's system and the effect of adding new high-interconnection cost customers to the system. Changes to address these new challenges include changes to Contracts and Agreements, Special Facilities, Standby Service, and other more minor changes. In addition, there are other tariffs supported by other OTP witnesses in this case.

Q. WHY IS OTP MAKING CHANGES TO ITS TARIFFS TO ADDRESS PARTIAL REQUIREMENTS CUSTOMERS?

A. Since OTP's last rate case, we have seen an increasing interest in our service territory of customers interested in behind-the-meter generation, largely due to recently enacted federal incentives. When OTP commissioned its Standby Tariff in the early 1990's, it was designed to accommodate new customers being added to the system who might need standby services – such as back-up power, maintenance and supplemental power. It was not designed to deal with existing customers who move from full to partial requirements service. OTP's proposed revisions are designed to reflect current market conditions where customers are moving from full to partial requirements service. When full-requirements customers move from their current tariff to a standby tariff, different requirements are necessary to protect OTP's other customers from absorbing extra costs. The proposed changes also ensure that certain benefits that primary meter customers have, like combining multiple points of interconnection on one account with one meter charge, are not available to partial-requirements customers. Each change is summarized in the Matrix of Tariff Changes included as Exhibit___(DGP-1), Schedule 4, and the full redlined text is available in Volume 2C.

Q. WHY IS OTP MAKING CHANGES TO ADDRESS HIGH-INTERCONNECTION-COST CUSTOMERS?

A. Another change that we have seen since the last rate case is potential new customers interested in connecting to OTP's system that have unusually high interconnection costs. To protect other customers from having to subsidize these unusually high interconnection costs, OTP has updated its standard contracts and special facilities tariffs to provide more security for cost outlays OTP makes to connect customers.

Q. ARE THERE ANY OTHER CHANGES OF NOTE?

A. Yes. OTP is making a number of improvements to its general rules and regulations to add glossary definitions, clarify that certain tariffs are only available to qualifying customers, identifying with increased specificity rate qualifications, and other enhancements, in addition to the changes discussed above. These improvements are also included in Exhibit___(DGP-1), Schedule 4.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?
A. Yes, it does.

Mr. David G. Prazak
Manager, Pricing & Rate Design
Regulatory Economics
215 South Cascade Street
Fergus Falls, Minnesota 56537
218-739-8595

CURRENT RESPONSIBILITIES (2012 – Present)

Manage the design and implementation of retail pricing strategies for rate schedule and contract pricing, including rates, rate design, and load research.

PREVIOUS POSITIONS

Otter Tail Power Company

2022-Present	Manager, Pricing & Rate Design
2019-2022	Supervisor, Pricing
2012-2019	Supervisor, Pricing & Tariff Administration
2000– 2012	Supervisor, Pricing
1997-2000	Senior Pricing Analyst

EPS Solutions

1990-1997	Associate I & II: Consultant in demand-side management planning, evaluation, and training

Northern States Power

1989-1990	Demand-Side Management (Intern): Aided in DSM activities

EDUCATION

Walden University	Masters of Public Administration, 2012
Minnesota State University, Moorhead	B.S., Energy Management, concentration in Industrial Technologies

Otter Tail Power Company

MARGINAL COST OF SERVICE STUDY

October 4, 2023

CRA Charles River Associates

Amparo Nieto
Principal

TABLE OF CONTENTS

1 INTRODUCTION

Charles River Associates was retained to prepare a Marginal Cost of Service Study (MCOS) on behalf of Otter Tail Power Company. This report summarizes the study approach to estimate OTP's overall marginal costs of service applicable during the period 2024 to 2028.

In electricity ratemaking, marginal costs are critical to design rates that incentivize economically efficient consumption patterns. A MCOS study informs the appropriate rate structure, differences in the hourly marginal cost associated with an additional kW of usage, appropriate time-of-use periods and price differentials across periods.

OTP's electricity marginal cost analysis required a review of the Midwest Independent System Operator (MISO)'s wholesale energy and capacity market rules and prices, expected near-term capacity conditions in the MISO region, transmission tariffs, Company's planned distribution substations and feeders, local connection costs, customer data.

2 TOU PERIODS

The costing Time of Use (TOU) periods used in this study were decided in consultation with the Company, upon review of hourly total marginal cost profiles for typical weekdays and weekends in each month. Table 1 below summarizes the new Time of Day (TOD) periods.

Table 1. OTP Time of Day and Seasonal Costing Periods

Summer: June – September	
Peak:	Monday - Friday, 1 pm - 7 pm
Shoulder	Monday - Friday, 11 am - 1 pm , 7 pm - 9 pm Weekends, 1 pm - 7 pm
Off-Peak	Monday - Friday, 9 pm to 11am Weekends, 7 pm - 1 pm
Winter: All other months	
Peak:	Monday - Friday, 7 am - 10 am
Shoulder:	Monday - Friday, 6 am - 7 am, 10 am - 9 pm
Off-Peak:	Monday - Friday, 9 pm - 6 am Weekends, all hours

In order for rates to provide efficient price signals to customers, the analysis of time periods must consider the prevailing conditions in the years when rates are expected to be in effect. The first step in our analysis was to compute all hourly marginal costs that change with time of day. These include generation, transmission and upstream primary distribution marginal costs. The analysis aims to group together hours with similar hourly marginal costs.

The TOU periods were defined for the seasons that the Company currently has in its existing rates. Modelling of hourly generation capacity cost involved a review of hourly net system loads in MISO during the prior 3 years and evaluating additions of solar and wind generation, expected during the upcoming 3 years (through 2026). Longer-term views will require reviewing the impact of future additions of renewable-based resources on MISO load profiles during the 2027-2030 timeframe, where cumulative wind, solar as well as storage capacity on-line will be expected to significantly increase in MISO and potentially shift peak period further into the evening, particularly for the summer months.[1] We recommend revisiting the TOU periods again at the next rate case. At that point, further granularity in seasons will be examined, given MISO's exposure to MISO seasonal construct. Decisions on TOU periods also evaluated probability of annual peak for every hour on the transmission and distribution systems.

3 MARGINAL GENERATION COSTS

3.1 Marginal Energy Costs

In a competitive electricity market, the marginal cost of generation is the market price of energy, as well as the market price of capacity if the change in demand occurs at a time of system peak demand. Estimating the hourly marginal generation capacity cost requires an estimate of annual capacity market prices in the MISO region, the target planning reserve margins by seasons, and cost allocation factors that are based on MISO's new reserve adequacy rules.

An increment of native load in any hour requires OTP to purchase more energy at the prevailing market prices or sell less to the market if OTP is a net seller in that hour. As a member of MISO's electricity wholesale market, OTP buys and sells on an hourly basis as needed to achieve the lowest cost of serving its retail customers. To update OTP's marginal energy costs, we relied on the latest forecast available of MISO's forward monthly peak and off-peak prices for the period January 2024 through December 2028. Forward market prices reflect MISO forward market energy prices for the Intercontinental Exchange (ICE), measured at the OTP node, based on historical hourly price differentials between the Indiana node and OTP's node. We converted the monthly energy peak and off-peak forward prices into hourly prices based on average variation in hourly day-ahead LMPs during the two-most recent years.

1 "Preliminary MTEP23 Review", September 12, 20023. About 31 GW of solar generation has been approved for interconnection in MISO, as well as 6 GW of wind, and 2 GW of energy storage, according to MISO's interconnection queue as of July 9 and approved projects. *Retrieved from Midcontinent Independent System Operator on September 14, 2023*

To convert market prices to energy marginal costs at customers' meters, market prices were adjusted for the financial cost of working capital required and marginal energy losses incurred from the OTP hub to customer meters. Section IX presents the resulting 2024-2028 marginal energy costs averaged by costing periods.

3.2 Marginal Generation Capacity Costs

MISO currently has a new seasonal resource adequacy capacity construct that replaced its single annual resource adequacy requirement with four seasonal resource adequacy requirements. The new seasons include summer, fall, winter and spring seasons, each with 3-month duration. To develop marginal capacity costs. OTP's marginal cost of generation capacity is triggered by changes in OTP's capacity obligation under MISO resource adequacy rules. The regional market capacity price represents OTP's opportunity costs when an OTP customer increases his usage at the time of MISO's seasonal coincident peak. MISO conducts a Loss of Load Expectation (LOLE) study that determines the required resources and Planning Reserve Margin (PRM) required to achieve the target LOLE level by season. MISO calculates seasonal PRMs calibrated to a LOLE is 1 day in 10 years.

OTP's marginal generation capacity cost in any hour on a planning basis is a function of the forecast seasonal capacity market price, which varies with the expected level of capacity surplus in MISO-wide region, the required PRM, which is applied to OTP's expected load coincident with the MISO seasonal peak, and the probability that each hour is MISO's system seasonal peak hour. This required a probability of peak analysis conducted for each of the four seasons defined under MISO seasonal construct. For the initial year of the timeframe, the seasonal capacity market prices reflect Zone 1 auction results from the 2023/2024 MISO capacity auction.

To estimate marginal generation capacity costs for the remaining period, the study uses a forecast of annual MISO capacity market prices developed by Wood McKenzie. Annual prices were apportioned to each of the four seasons based on MISO predictions of evolution of PRM and relative LOLE by season, which data published by MISO for the period 2023 - 2028.

We allocated the quarterly market capacity prices to each month within the season based on hourly probability of being the season's peak hour, using a profile of hourly MISO-net system peak loads in recent years In the final step, the monthly probabilities of peak were combined in order to obtain the market capacity price estimates according to the Company's preferred seasonality in its retail rates, i.e., two seasons, summer (June-Sep) and winter (Oct – May). Table 2 in Section 7 summarizes the marginal generation capacity cost averaged for the five-year planning period.

3.3 Marginal Transmission Costs

OTP operates in a joint pricing zone within the Midwest ISO. OTP's transmission system consists of 345 kV, 230 kV, 115 kV, 69 kV and 41.6 kV facilities. Any transmission lines above 100 kV are under the functional control and planning of MISO and included as part of the Network Upgrade Charge (NUC). OTP has operational control of its transmission facilities at or below 100 kV. These facilities, plus those projects above 115 kV that are below $5 million, are considered by FERC in setting MISO Network Integration Transmission Service (NITS) rate for its Control Area. OTP's control area NITS rate also includes the transmission facilities of Great River Energy (GRE). Both the MISO NITS and NUC charges are constant every month, reflecting 1/12 of the applicable annual revenue requirement per kW.

Network Integration Transmission Service Rate

The NITS rate is recovered from each transmission user in the OTP Pricing Zone based on their monthly coincident peak loads. An increase in monthly coincident peak triggers an increase in MISO transmission bill, thus the NITS rate represents a financial marginal cost to OTP. Forecasting annual changes to OTP's NITS rate requires a review of OTP's transmission budgets for 115-kV below $5 million, 41.6 kV and 69 kV projects expected to come into service in the period 2022-2026, excluding projects that qualify for recovery through the transmission cost rider (TCR). We applied MISO's estimates of annual carrying charge to OTP's transmission investment to compute an annual incremental revenue requirement for the OTP Pricing Zone's NITS. Projections of 12 monthly OTP's control area CPs were used to estimate annual changes to OTP's NITS charge.

The forecasted monthly NITS rates for the period 2022-2026 were allocated to hours based on the probability that a given hour is the monthly peak on OTP's Control Area. The hourly transmission costs were adjusted by marginal losses and summarized by costing period. Section 7 provides the time-differentiated marginal transmission costs, averaged for 2024-2028 and stated both on a per-kWh and a per-kW basis.

Network Upgrade Charge

To estimate the second component of the financial transmission marginal cost, the NUC rate, we relied on MISO's calculation of projected annual revenue requirement as per Schedule 26. The cost of all new projects rated 345 kV and above with a project cost of $5M or greater is allocated through a hybrid method, so that 20% of the costs are allocated on a system-wide basis and the remaining 80% are allocated to planning sub-regions (West, Central and East) and pricing zones under a method that differs between economic and reliability projects. Costs of transmission projects rated below 345-kV, get allocated on a zonal basis based on each pricing zone's contribution to MISO's average 12 CPs.

To estimate the NUC charges corresponding to the OTP Pricing Zone for the period 2024 through 2028, MISO's NUC-related annual transmission revenue requirements allocated to OTP's pricing zone were divided by the sum of 12 CPs in the OTP zone to establish the corresponding NUC rate. The projected NUC charges were time-differentiated using the probability of peak analysis of OTP's control area.

Multi-Value Projects

In addition to the NITS and NUC charges, MISO included a transmission project rate category designated to recover the cost of Multi-Value Projects. These projects are driven by energy policy mandates and can address various reliability and/or economic issues, affecting multiple transmission zones. FERC determines, on an annual basis, a Multi-Value Project Usage Rate (MUR) on a per-MWh basis to recover these costs. OTP is required to pay these costs for every kWh of its native load and therefore it is a financial marginal cost component. The MCOS study calculates the MUR rate adjusted by energy losses at each voltage level of service.

Marginal Ancillary Service Costs

OTP must procure ancillary services in MISO markets to meet OTP's incremental net load in a given hour. The two types of ancillary services considered in the analysis are regulation and operating reserves (spinning and supplemental). The MCOS study relies on a forecast of average annual hourly cost stated in dollars per MWh, for each type of reserve estimated for year 2024-28. The expected average hourly cost was adjusted by marginal losses at each service voltage level and working capital, and time-differentiated using as a proxy hourly variation of energy market prices.

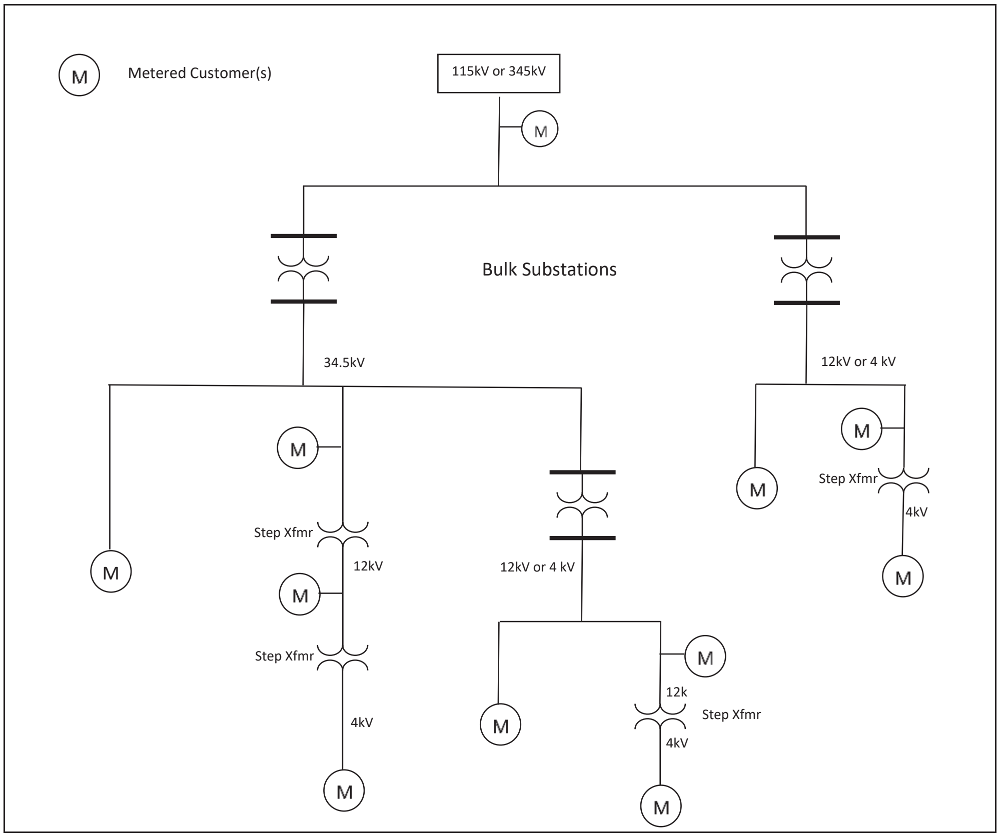
4 MARGINAL DISTRIBUTION COSTS

For purposes of estimating marginal costs of delivery, it is important to understand the configuration of the grid and determine what drives new investment. From this point of view, the costs of service can be grouped in four main categories:

1. Upstream distribution substations that are fed from the transmission system (115kV) and typically convert power to 34.5 kV.
2. Distribution substations that generally convert the power from 34.5 kV to 12 kV or directly 4 kV, and trunk-line primary feeders.
3. Local distribution facilities (line transformers, local primary taps, and secondary conductors)
4. Customer-related facilities and functions, including:
    a) Meters and service drops
    b) Customer-related services (*e.g.*, meter-reading, billing, accounting, customer information and customer service).

Figure 1 is a simplified diagram of OTP's electric distribution system.

Figure 1. OTP's Illustrative Electric Delivery System Diagram



4.1 Distribution Substation and Trunkline Feeder Costs

The distribution stations and trunkline feeders from the substation to the point where the line branches to create a primary tap line are expanded as the distribution area peak demands grow. Estimating the marginal cost of distribution substation and trunkline feeder cost per kW of demand required identifying the budgeted growth-related investments in OTP's most recent capital expansion plan. The sum of OTP's growth-related investment (stated in 2024 dollars) was divided by the estimated total growth in distribution substation non-coincident peak demands over the same period to obtain marginal investment per kW.

Distribution O&M expenses are a component of marginal distribution cost, since they grow with the amount of plant in service. OTP's annual distribution station O&M expenses during the period 2020-2022, stated in 2024 dollars, were divided by historical non-coincident peak demands across substations. After reviewing the trend in expenses per kW (in constant dollars), the four-year average of O&M expense per kW was considered a reasonable proxy for the marginal substation O&M expense.

To time differentiate the annualized distribution substation cost, the relative probability of distribution peak for months, day-types (weekdays, Saturday, and Sunday) were estimated based on historical hourly loads across OTP distribution substations. The analysis accounted for the relative lower carrying capability of this equipment in summer months as compared to the winter months. Peak demand loss factors were developed from OTP's 2020 loss study.

4.2 Local Distribution Facility Costs

The local distribution facilities, including secondary lines, line transformers, and local primary taps, are less extensively shared than the distribution substations. OTP engineers decide on the type of the required facilities using sizing standards that take into consideration the number of customers who are expected to use those facilities, their maximum loads over the service life of the facilities and other parameters such as the level of maximum transformer loading that can be expected to be safe. Thus, the marginal cost of local distribution facilities is strongly influenced by the connected customers' "design demands", i.e., the maximum long-term load that customers may impose on the transformer and conductor. Fluctuations of actual customer demand from month to month or even year to year are not expected to require a change in the installed facility.

Local distribution facility costs were estimated for residential, commercial and industrial customers and type of customer within each major rate class. The analysis used different connection scenarios. OTP provided transformer size and conductor costs from OTP's work order system, as well as an estimate of number of customers typically connected under each scenario. Marginal facilities costs were estimated as the monthly distribution cost per kW of customer's design demand. The design demands for various scenarios are affected by density (rural versus urban areas), whether it is a single customer vs. multi-unit building, and whether customers connected use all electric appliances instead of relying partially on gas. Design demand and cost of facilities also vary depending on whether the installation is underground or overhead, single-phase or three-phase.

To obtain an estimate of residential customer design demand, we reviewed the typical transformer sizes used for different types of customer connections and divided transformer capacity by the number of customers expected to be served, adjusted by a percentage of typical transformer utilization level provided by OTP to state the cost as a dollar per kW of long-term maximum demand as opposed to cost per required capacity. The streetlighting marginal distribution feeder cost was estimated on a per-fixture basis.

The marginal distribution facility O&M expenses were estimated using recent historical data, since a forecast of O&M expenses was not available. The average expense per kW of design demand averaged 2020 -2022 was used as the estimated future distribution facilities O&M expense going forward. The total design demand was the product of customer counts and per-customer average design demand estimates by rate.

5 MARGINAL CUSTOMER COSTS

5.1 Meter and Service Costs

OTP provided 2023 installed cost of a typical AMI meter, since OTP expects full deployment of smart meters over the next two years. The average per-meter O&M expense from recent years was used to represent the marginal level of these expenses. The MCOS study separately calculated meter requirements for small power producers, which vary with the specific rider and/or jurisdictional legislation. When a bi-directional and/or a generation meter are required for reporting purposes, there are incremental installed meter costs compared to the standard meter. The MCOS study includes a calculation of these incremental costs by DG rate category.

5.2 Customer Accounts and Customer Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are a function of customers on the system. OTP's FERC Form 1 recent customer account and service expense levels were divided by class weighted customers to obtain an estimate of customer accounts expense per weighted customer. We estimated that the marginal customer service and informational expenses, which include the costs of disseminating information to consumers, vary with the number of customers on the system and are, therefore, marginal. Expenses associated with CIP and EEP, programs mandated by MN and SD to promote demand side measures, were omitted from the study since they are not marginal with respect to customer additions. Other non-marginal customer account and customer service and informational subaccounts were also excluded. The same procedure was used to allocate customer accounts expenses using the class weights developed for these expenses in embedded cost of service study. The average of 2020 through 2022 values was considered a reasonable proxy of the future marginal per-customer expense.

6 ANNUALIZED MARGINAL COSTS

The MCOS annualized marginal cost for each component of service by multiplying all marginal investment by an annual economic carrying charge, expressed as a percentage, and adjusting the investment per unit by the general plant loading factor and a plant-related A&G loading factor. To these costs, marginal O&M, adjusted by non-plant related A&G expenses, and revenue requirements for working capital, were added to obtain the total annualized marginal unit cost. A summary of the calculation of these components is provided below.

6.1 Loaders

Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. The MCOS estimated loading factors, in particular, plant-related A&G, non-plant-related A&G and general plant loading factors. Accounts not marginal with respect to other expenses or plant were excluded. The MCOS uses a non-plant-related A&G loader estimated based on the average ratio of non-plant-related A&G expenses (FERC Accounts 926 and 408.1) to O&M expenses over the period 2012-2022.

For plant-related A&G, two A&G FERC accounts were identified to vary with the amount of plant in service: FERC Account 935 and FERC Account 924. Account 935 was regressed on cumulative net additions to total electric plant, all in constant dollars. Average property and terrorism insurance rate, which applies to distribution substations only, was used to estimate insurance loading factor. General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. These may grow with electric plant expansion. The MCOS uses a General Plant loader based on a regression of cumulative net additions to general plant on cumulative net additions to total plant (less General plant). Since 1996 there has been very little change in OTP's general plant.

6.2 Economic Carrying Charges

To convert estimates of marginal distribution plant investment into annual costs requires estimating an economic carrying charge that reflects the elements of OTP's revenue requirement associated with incremental plant. Inputs to the economic carrying charge calculation include: the utility's incremental cost of capital (mix of debt and equity and their respective long-term market costs), the expected inflation rate for that type of plant, net of technical progress, and the average service life and patterns of failure ("Iowa curve") for each type of plant.

OTP foresees financing of incremental investment through a combination of debt and sales of common stock (about 47 percent and 53 percent, respectively). The ECC calculation uses the average long-term incremental cost of debt and the long-term incremental cost of equity over the next ten years.

6.3 Working capital

The computation of working capital includes cash, materials, supplies and prepayments. The revenue requirement associated to working capital reflects OTP's weighted average cost of capital plus an income tax component that recognizes the taxable equity portion of the return on capital.

7 SUMMARY OF MARGINAL COSTS

7.1 Marginal costs time-differentiated by season and time of day

The time-differentiated marginal costs (including energy, generation capacity, transmission and distribution substation costs), in 2024$, were averaged over the 2024-2028 timeframe for each of the current periods in TOD rates. Tables 2 and 3 show the results on a per-kWh basis and on a per-kW basis, respectively.

Table 2. Summary of 2024-2028 Time-differentiated Marginal Costs ($ per-kWh)

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	---------------------------- (2024 Cents per kWh) --------------------------					
Secondary						
Energy	6.3262	5.1235	3.2859	5.6545	5.1415	4.4008
Generation Capacity	1.6417	0.5813	0.0219	0.2120	0.1725	0.0190
Op. Reserves	0.0929	0.0755	0.0485	0.0822	0.0750	0.0643
Transmission NITS/NUC	3.2249	0.6904	0.1036	3.5720	0.9346	0.2629
Transmission MUR	0.1698	0.1686	0.1677	0.1741	0.1726	0.1718
Distribution Substation	0.0340	0.0088	0.0001	3.5469	0.5129	0.1945
Total TOU	**11.4896**	**6.6481**	**3.6277**	**13.2417**	**7.0092**	**5.1132**
Primary						
Energy	6.1574	4.9961	3.2087	5.4679	4.9828	4.2706
Generation Capacity	1.5739	0.5575	0.0210	0.2010	0.1645	0.0181
Op. Reserves	0.0904	0.0734	0.0472	0.0799	0.0729	0.0625
Transmission NITS + NUC	3.0901	0.6618	0.0992	3.3531	0.8781	0.2467
Transmission MUR	0.1653	0.1670	0.1664	0.1711	0.1700	0.1694
Distribution Substation	0.0328	0.0085	0.0001	3.4254	0.4954	0.1879
Total TOU	**11.1099**	**6.4643**	**3.5426**	**12.6983**	**6.7636**	**4.9552**
Transmission						
Energy	6.0039	4.8798	3.1381	5.3006	4.8399	4.1532
Generation Capacity	1.4670	0.5199	0.0196	0.1841	0.1520	0.0167
Op. Reserves	0.0880	0.0715	0.0460	0.0776	0.0709	0.0608
Transmission NITS/NUC	2.8776	0.6166	0.0924	3.0256	0.7935	0.2225
Transmission MUR	0.1611	0.1605	0.1601	0.1632	0.1625	0.1621
Total	**10.5975**	**6.2483**	**3.4562**	**8.7512**	**6.0187**	**4.6154**

Table 3. Summary of 2024-2028 Time-Differentiated Marginal Capacity Costs ($ per-kW)

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	($/kW-mo)					
Secondary						
Monthly Costs per kW						
Generation Capacity	$2.14	$0.91	$0.10	$0.14	$0.46	$0.08
Transmission	$4.21	$1.08	$0.46	$2.36	$2.47	$1.05
Distribution Substation	$0.04	$0.01	$0.00	$2.34	$1.35	$0.78
Total TOU MC	**$6.40**	**$2.01**	**$0.56**	**$4.84**	**$4.28**	**$1.90**
Monthly Average, seasonal	**$8.96**			**$11.02**		
Monthly Average, year-round	**$10.33**					
Primary						
Monthly Costs per kW						
Generation Capacity	$2.05	$0.88	$0.09	$0.13	$0.43	$0.07
Transmission	$4.03	$1.04	$0.44	$2.21	$2.32	$0.98
Distribution Substation	$0.04	$0.01	$0.00	$2.26	$1.31	$0.75
Total TOU MC	**$6.13**	**$1.93**	**$0.54**	**$4.61**	**$4.06**	**$1.81**
Monthly Average, seasonal	**$8.59**			**$10.47**		
Monthly Average, year-round	**$9.85**					
Transmission						
Monthly Costs per kW						
Generation Capacity	$1.91	$0.82	$0.09	$0.12	$0.40	$0.07
Transmission	$3.76	$0.97	$0.41	$2.00	$2.09	$0.89
Total TOU MC	**$5.67**	**$1.78**	**$0.50**	**$2.12**	**$2.50**	**$0.95**
Monthly Average, seasonal	**$7.95**			**$5.57**		
Monthly Average, year-round	**$6.36**					

7.2 Marginal Local Distribution Facilities Costs

Table 4 summarizes the monthly marginal local distribution facilities costs, stated as a fixed monthly cost per kW of customer’s design demand (which may be the basis for a per-contract or customer-specific subscription demand). It is also stated as a fixed per customer cost by class, using the average customer design demand. Local distribution facilities cost in the fixed charge assumes that the average kW of transformer capacity required per customer is representative of the majority of the customers in the same class.

Table 4: Monthly Marginal Local Distribution Facilities Costs

Customer Class	Monthly Facility Cost per kW of Design Demand	Estimate of Typical Design Demand by Customer	Monthly Facility Cost per Customer
	($/kW)	kW	($/customer/mo.)
Residential			
Single Family Urban	$1.87	8.0	$14.93
Single Family Rural	$4.97	10.0	$49.75
Apartment Gas	$2.03	5.0	$10.13
Apartment Electric	$1.48	7.0	$10.33
Farm	$5.61	20.0	$112.19
Small Commercial			
Stand-Alone customer 1-ph, OH	$1.48	18.0	$26.64
Stand-Alone customer 3ph, OH	$1.48	45.0	$66.58
Shared-customer 3ph, OH	$1.39	25.0	$34.83
Stand-Alone customer 1ph, UG	$3.17	24.0	$76.07
Stand-Alone 3ph, UG	$3.10	45.0	$139.56
Large Commercial (Secondary)			
101-150kVa, 3ph	$1.45	125.0	$181.65
151-300kVa, 3ph	$1.14	230.0	$263.26
301-500kVa, 3ph	$0.92	400.0	$369.26
501-1000 kVa, 3ph	$0.75	775.0	$579.48
Large Commercial (Primary)			
101-500kVa, 3ph	$0.52	500.0	$262.40
501-1000 kVa, 3ph	$0.75	1,000.0	$747.72
Very Large Commercial (Secondary)			
1001-1500 kVa, 3ph	$0.72	1,250.0	$896.66
1501-2000 kVa, 3ph	$0.65	1,750.0	$1,132.08
Very Large Commercial (Primary)			
3000 kVa (LGS), 3ph	$0.53	2,500.0	$1,319.93
5000 kVa (LGS TOU), 3ph	$0.46	4,000.0	$1,821.72

7.3 Marginal Monthly Customer Costs

Table 5 summarizes the monthly marginal customer cost by customer class. Table 6 summarizes the monthly marginal cost for small power producers by rate class.

Table 5. Summary of Monthly Marginal Customer Costs

		Monthly Marginal Customer Cost (2024 $/acc/mo.)
	Residential	
9.01	Residential Service	$17.07
9.02	Residential Demand Control	$21.37
9.04	Residential Service Time of Day	$18.60
14.01	Residential Water Heating Control Rider	$6.45
14.04	Residential Controlled Service - Large Dual Fuel Rider	$25.99
14.05	Residential Controlled Service - Small Dual Fuel Rider	$6.40
14.06	Residential Controlled Service - Deferred Load Rider	$9.10
14.07	Residential Fixed Time of Service Rider	$6.34
	Commercial and Industrial	
9.03	Farm Service	$21.71
10.01	Small General Service <20 kW	$24.19
10.02	General Service >= 20 kW	$54.23
10.03	General Service - Time of Use	$99.98
10.04	Large General Service (Secondary)	$113.62
	Large General Service (Primary)	$239.31
10.05	Large General Service - Time of Day (Secondary)	$108.29
	Large General Service - Time of Day (Primary)	$239.31
14.01	Commercial Water Heating Control Rider	$5.16
14.02	LGS - Real Time Pricing Rider (Secondary)	$86.97
	LGS - Real Time Pricing Rider (Primary)	$213.49
14.04	Commercial Controlled Service - Large Dual Fuel Rider	$33.41
14.05	Commercial Controlled Service - Small Dual Fuel Rider	$5.74
14.06	Commercial Controlled Service - Deferred Load	$16.76
14.07	Commercial Fixed Time of Service Rider	$16.76
	Miscellaneous	
11.05, 11.06	Other Public Authority	$33.45
11.02	Irrigation Service	$35.62
11.03	Outdoor Lighting	$3.59
11.03 11.04	Outdoor Lighting (unmetered)	$1.41

Table 6. Monthly Marginal *Incremental* Customer Cost of Small Power Producers by Rate Class

	Monthly *Incremental* Small PP Customer Cost (2024 $ /acc./mo.)
Residential Small Power Producer	
Residential	$0.87
Residential Demand Control	$0.99
Residential Water Heating Control Rider	$0.82
Residential Controlled Service - Deferred Load	$0.91
Commercial and Industrial Small Power Producer	
Small General Service <20 kW	2.21
General Service >= 20 kW	1.67
Farm Service	1.27
General Service - Time of Use	1.39
Large General Service (Secondary)	1.87
Large General Service (Primary)	1.07
Large General Service - Time of Day (Secondary)	1.12
Large General Service - Time of Day (Primary)	1.07
Commercial Controlled Service - Large Dual Fuel Rider	1.60
Commercial Controlled Service - Small Dual Fuel Rider	0.69
Miscellaneous	
Other Public Authority	1.38
Irrigation Service	1.50

Customers under the Small Power Producer Rider are responsible for the one-time marginal cost incurred by OTP when processing and energizing the interconnection. The MCOS estimated the cost of reviewing the application form filled out by the customer, performing a site inspection and interconnection study, and conducting a final site visit prior to the energizing of the generator. The resulting cost was adjusted for loaders and cash working capital. Table 7 reflects this calculation.

Table 7. One-Time Interconnection Expense per Small Power Producer

Small Power Producer Rider	Interconnection Labor Cost (2024$)
Average Annual Salary of Technical & Admin Personnel Involved	$115,245.40
Annual hours net of paid vacation & holiday	1,880.00
Hourly average labor cost	$61.30
Hours required per interconnection	$20.00
Expense per Interconnection Request	$1,226.01
With Non-Plant Related A&G	$1,275.18
Working Capital	
Cash Working Capital	85.05
Revenue Requirement for Working Capital	$7.55
Total One-time Incremental Cost to Process and Energize Interconnection	$1,282.73

APPENDIX A: DERIVATION OF ANNUALIZED MARGINAL COSTS

Tables A.1.1 through A.1.7 show the steps used in the derivation of the annualized marginal distribution substation and trunkline feeder costs, annualized marginal cost of local distribution facilities, and the annualized marginal customer-related costs.

Table A.1.1. Annualized Distribution Substation Costs

	2024 $/kW
Marginal Investment per kW	$336.45
With General Plant Loading	355.59
Annual Economic Carrying Charge Related to Capital Investment	8.10%
A&G Loading (plant related)	0.14%
Total Annual Carrying Charge	8.24%
Annualized Costs	29.30
O&M Expenses	3.10
With A&G	3.20
Subtotal	32.50
Material, Supplies and Prepayments	3.87
Cash Working Capital Allowance	0.21
Revenue Requirement for Working Capital	0.36
Total Distribution Substation Annual Cost	$32.86

Table A.1.2 Annualized Distribution Facilities Costs, Residential, Farm, Small Commercial

	Residential & Farm					Small Commercial				
	Single Family Urban	Single Family Rural	Apartment Gas	Apartment Electric	Farm	Stand-Alone customer 1-ph, OH	Stand-Alone customer 3ph, OH	Shared-customer 3ph, OH	Stand-Alone customer 1ph, UG	Stand-Alone 3ph, UG
Marginal Investment per kW of Design Demand	$223.00	$720.66	$248.51	$160.49	$822.24	$161.27	$161.16	$147.37	$431.67	420.77
General Plant Loading	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569
Annual Economic Carrying Charge Related to Capital Investment	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%
A&G Loading (plant-related)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Total Annual Carrying Charge	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Annualized Costs	$16.49	$53.29	$18.38	$11.87	$60.80	$11.93	$11.92	$10.90	$31.92	$31.11
Annual O&M Expense per kW of Design Demand	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45
With A&G Loading x 1.0337	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64
Subtotal Distribution Facilities Marginal Costs	$22.13	$58.93	$24.02	$17.51	$66.44	$17.56	$17.56	$16.54	$37.56	$36.75
Working Capital Rev. Req.										
Material, Supplies and Prepayments	$0.23	$0.74	$0.25	$0.16	$0.84	$0.16	$0.16	$0.15	$0.44	$0.43
Cash Working Capital Allowance	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
Total Annualized Marginal Facilities Cost per kW of Design Demand ($/kW-yr	**$22.39**	**$59.70**	**$24.30**	**$17.70**	**$67.31**	**$17.76**	**$17.75**	**$16.72**	**$38.03**	**$37.22**

Table A.1.3. Annualized Distribution Facilities Costs, Large Commercial

	Large Commercial (Secondary)				Large Commercial (Primary)		Very Large Commercial (Secondary TOU)		Very Large Commercial (Primary)	
	101-150kVa, 3ph	151-300kVa, 3ph	301-500kVa, 3ph	501-1000 kVa, 3ph	101-500kVa, 3ph	501-1000 kVa, 3ph	1001-1500 kVa, 3ph	1501-2000 kVa, 3ph	3000 kVa (LGS), 3ph	5000 kVa (LGS TOU), 3ph
Marginal Investment per kW of Design Demand	$156.95	$107.55	$72.10	$44.02	$8.34	$13.91	$39.16	$27.89	$38.06	$26.45
General Plant Loading	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569	1.0569
Annual Economic Carrying Charge Related to Capital Investment	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%	6.98%
A&G Loading (plant-related)	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%	0.02%
Total Annual Carrying Charge	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%	7.00%
Annualized Costs	$11.61	$7.95	$5.33	$3.26	$0.62	$1.03	$2.90	$2.06	$2.81	$1.96
Annual O&M Expense per kW of Design Demand	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$5.45	$3.35	$3.35
With A&G Loading x 1.0337	5.64	5.64	5.64	5.64	5.64	5.64	5.64	5.64	3.46	3.46
Subtotal Distribution Facilities Marginal Costs	$17.24	$13.59	$10.97	$8.89	$6.26	$6.67	$8.53	$7.70	$6.28	$5.42
Working Capital Rev. Req.										
Material, Supplies and Prepayments	$0.16	$0.11	$0.07	$0.05	$0.01	$0.01	$0.04	$0.03	$0.04	$0.03
Cash Working Capital Allowance	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.02	$0.02
Total Annualized Marginal Facilities Cost per kW of Design Demand ($/kW-yr)	**$17.44**	**$13.74**	**$11.08**	**$8.97**	**$6.30**	**$6.71**	**$8.61**	**$7.76**	**$6.34**	**$5.47**

Table A.1.4. Annualized Customer-Related Marginal Costs for Residential Customers

	Residential							
	Residential Service	Residential Demand Control	Residential Service Time of Day	Residential Water Heating Control	Residential Controlled Service - Large Dual	Residential Controlled Service - Small Dual	Residential Fixed Time of Service Rider	Residential Controlled Service - Deferred
nstalled Meter Cost	$126.79	$572.40	$275.44	$428.48	$2,038.37	$435.69	$437.51	$766.00
With General Plant Loading	$134.01	$604.97	$291.12	$452.86	$2,154.35	$460.48	$462.40	$809.58
Subtotal Annualized Meter Costs	$12.63	$57.01	$27.43	$42.67	$203.01	$43.39	$43.57	$76.29
With A&G Loading (Plant Related)	$12.65	$57.13	$27.49	$42.77	$203.44	$43.48	$43.67	$76.45
Meter O&M Expenses	$10.57	$16.91	$13.74	$10.57	$81.22	$10.57	$10.57	$10.57
Meter O&M with A&G loading	$10.93	$17.48	$14.20	$10.93	$83.96	$10.93	$10.93	$10.93
Sub-total Meter Installed Cost	**$23.58**	**$74.61**	**$41.70**	**$53.69**	**$287.41**	**$54.41**	**$54.59**	**$87.38**
nstalled Service Cost	$1,239.94	$1,239.94	$1,239.94	-	-	-	-	-
With General Plant Loading x 1.0569	$1,310.49	$1,310.49	$1,310.49	-	-	-	-	-
Annualized Service Drop Costs	$91.43	$91.43	$91.43	-	-	-	-	-
Subtotal Service with Plant-related A&G	**$91.69**	**$91.69**	**$91.69**	-	-	-	-	-
ustomer services								
Customer Accounts Expenses	$75.33	$75.33	$75.33	$22.25	$21.02	$21.02	$20.19	$20.19
Customer Service & Informational Expenses	$9.44	$9.44	$9.44	$0.02	$0.06	$0.06	$0.03	$0.03
Sub-total Cust. Expenses with A&G Loading	**$87.63**	**$87.63**	**$87.63**	**$23.02**	**$21.79**	**$21.79**	**$20.90**	**$20.90**
Working Capital Rev. Req.								
Material, Supplies and Prepayments	$1.40	$1.85	$1.55	$0.44	$2.08	$0.45	$0.45	$0.78
Cash Working Capital	$0.58	$0.62	$0.60	$0.20	$0.61	$0.19	$0.19	$0.19
Total Annual Marginal Customer Costs ($ /account/yr)	**$204.88**	**$256.40**	**$223.16**	**$77.35**	**$311.89**	**$76.84**	**$76.13**	**$109.25**

Table A.1.5. Annualized Customer-Related Marginal Costs for Commercial Customers

	General Service			Farm	Large General Service	
	Small General Service <20 kW	General Service >= 20 kW	General Service - Time of Use	Farm Service	Large General Service (Secondary)	Large General Service (Primary)
Installed Meter Cost	$390.43	$2,136.46	$1,700.25	$633.55	$2,378.96	$6,037.96
With General Plant Loading	$412.64	$2,258.02	$1,797.00	$669.60	$2,514.32	$6,381.52
Subtotal Annualized Meter Costs	$38.89	$212.78	$169.34	$63.10	$236.93	$601.35
With A&G Loading (Plant Related)	$38.97	$213.23	$169.70	$63.23	$237.44	$602.63
Meter O&M Expenses	$16.91	$129.96	$259.92	$16.91	$259.92	$1,299.59
Meter O&M with A&G loading	$17.48	$134.34	$268.68	$17.48	$268.68	$1,343.39
Sub-total Meter Installed Cost	**$56.45**	**$347.57**	**$438.37**	**$80.72**	**$506.11**	**$1,946.02**
Installed Service Cost	$1,505.34	$2,397.10	$2,397.10	$1,437.95	$3,352.78	$4,132.21
With General Plant Loading x 1.0569	$1,590.99	$2,533.50	$2,533.50	$1,519.77	$3,543.55	$4,367.33
Annualized Service Drop Costs	$111.00	$176.75	$176.75	$106.03	$247.22	$304.69
Subtotal Service with Plant-related A&G	**$111.31**	**$177.26**	**$177.26**	**$106.33**	**$247.93**	**$305.56**
Customer services						
Customer Accounts Expenses	$107.02	$107.02	$107.02	$60.11	$129.76	$129.76
Customer Service & Informational Expenses	$8.89	$8.89	$449.21	$8.47	$449.21	$449.21
Sub-total Cust. Expenses with A&G Loading	**$119.82**	**$119.82**	**$574.97**	**$70.89**	**$598.48**	**$598.48**
Working Capital Rev. Req.						
Material, Supplies and Prepayments	$1.94	$4.63	$4.19	$2.12	$5.86	$10.40
Cash Working Capital	$0.81	$1.48	$4.95	$0.52	$5.08	$11.24
Total Annual Marginal Customer Costs ($ /account/yr)	**$290.33**	**$650.76**	**$1,199.74**	**$260.58**	**$1,363.46**	**$2,871.70**

Table A.1.6. Annualized Customer-Related Marginal Costs Large Commercial Customers

	Large General Service				Commercial Riders				
	LGS - Real Time Pricing Rider (Secondary)	LGS - Real Time Pricing Rider (Primary)	Large General Service - Time of Day (Secondary)	Large General Service - Time of Day	Commercial Water Heating Control Rider	Commercial Controlled Service - Large Dual	Commercial Controlled Service - Small Dual	Commercial Controlled Service - Deferred	Commercial Fixed Time of Service Rider
nstalled Meter Cost	$1,700.25	$6,037.96	$1,700.25	$6,037.96	$275.44	$2,419.04	$290.78	$437.51	$437.51
With General Plant Loading	$1,797.00	$6,381.52	$1,797.00	$6,381.52	$291.12	$2,556.69	$307.32	$462.40	$462.40
Subtotal Annualized Meter Costs	$169.34	$601.35	$169.34	$601.35	$27.43	$240.93	$28.96	$43.57	$43.57
With A&G Loading (Plant Related)	$169.70	$602.63	$169.70	$602.63	$27.49	$241.44	$29.02	$43.67	$43.67
Meter O&M Expenses	$259.92	$1,299.59	$259.92	$1,299.59	$10.57	$129.96	$16.91	$129.96	$129.96
Meter O&M with A&G loading	$268.68	$1,343.39	$268.68	$1,343.39	$10.93	$134.34	$17.48	$134.34	$134.34
Sub-total Meter Installed Cost	**$438.37**	**$1,946.02**	**$438.37**	**$1,946.02**	**$38.42**	**$375.78**	**$46.50**	**$178.01**	**$178.01**
nstalled Service Cost	-	-	$3,412.60	$4,132.21	-	-	-	-	-
With General Plant Loading x 1.0569	-	-	$3,606.77	$4,367.33	-	-	-	-	-
Annualized Service Drop Costs	-	-	$251.63	$304.69	-	-	-	-	-
Subtotal Service with Plant-related A&G	**-**	**-**	**$252.35**	**$305.56**	**-**	**-**	**-**	**-**	**-**
ustomer services									
Customer Accounts Expenses	$129.76	$129.76	$129.76	$129.76	$22.25	$21.02	$21.02	$21.02	$21.02
Customer Service & Informational Expenses	$449.21	$449.21	$449.21	$449.21	$0.02	$0.06	$0.06	$0.03	$0.03
Sub-total Cust. Expenses with A&G Loading	**$598.48**	**$598.48**	**$598.48**	**$598.48**	**$23.02**	**$21.79**	**$21.79**	**$21.76**	**$21.76**
Working Capital Rev. Req.									
Material, Supplies and Prepayments	$1.74	$6.17	$5.23	$10.40	$0.28	$2.47	$0.30	$0.45	$0.45
Cash Working Capital	$5.08	$11.24	$5.08	$11.24	$0.20	$0.90	$0.23	$0.90	$0.90
Total Annual Marginal Customer Costs	**$1,043.68**	**$2,561.92**	**$1,299.52**	**$2,871.70**	**$61.92**	**$400.94**	**$68.82**	**$201.11**	**$201.11**

Table A.1.6. Annualized Customer-Related Marginal Costs - Irrigation and Lighting

	Other Rates			
	Irrigation Service	Other Public Authority	Outdoor Lighting	Outdoor Lighting (unmetered)
Installed Meter Cost	$1,379.30	$584.01	$275.44	-
With General Plant Loading	$1,457.78	$617.24	$291.12	-
Subtotal Annualized Meter Costs	$137.37	$58.16	$27.43	-
With A&G Loading (Plant Related)	$137.66	$58.29	$27.49	-
Meter O&M Expenses	$81.22	$129.96	$0.00	-
				-
Meter O&M with A&G loading	$83.96	$134.34	$0.00	-
Sub-total Meter Installed Cost	**$221.63**	**$192.63**	**$27.49**	-
Installed Service Cost	$1,420.82	$1,605.91	$124.11	$145.47
With General Plant Loading x 1.0569	$1,501.67	$1,697.29	131.17	$153.74
Annualized Service Drop Costs	$104.76	$118.41	9.15	$10.73
Subtotal Service with Plant-related A&G	**$105.06**	**$118.75**	**9.18**	**$10.76**
Customer services				
Customer Accounts Expenses	$84.01	$74.95	$4.71	$4.71
Customer Service & Informational Expenses	$9.70	$8.73	$1.02	$1.02
Sub-total Cust. Expenses with A&G Loading	**$96.87**	**$86.50**	**$5.92**	**$5.92**
Working Capital Rev. Req.				
Material, Supplies and Prepayments	$2.86	$2.24	$0.41	$0.15
Cash Working Capital	$1.05	$1.28	$0.04	$0.04
Total Annual Marginal Customer Costs ($ /account/yr)	**$427.47**	**$401.40**	**$43.04**	**$16.86**

Test Year 2024 Operating Revenue Summary Comparison with Marginal Cost Revenue - By Rate Schedule

Line No.	CCOSS or EPMC Method	Rate Schedule	Operating Revenues: Present	Operating Revenues: Proposed	Difference	Change in Base Revenues	2024 Average Revenue 100% Marginal Cost	2024 Proposed Revenue as % of 100% MC	Marginal Revenue Allocation
1	Class Level Increase	9.01 Residential Service (Rate 101)	$ 32,153,465	$ 44,251,924	$ 12,098,459	37.63%	$ 43,489,167	101.75%	85.9%
2		9.02 Residential Demand Control (Rate 241)	$ 4,780,572	$ 6,672,708	$ 1,892,136	39.58%	$ 7,127,595	93.62%	14.1%
3		**Total Residential:**	**$ 36,934,037**	**$ 50,924,632**	**$ 13,990,595**	**37.88%**	**$ 50,616,763**	**100.61%**	**100.0%**
4									
5	Class Level Increase	9.03 Farm Service (Rate 361)	$ 1,830,773	$ 2,565,269	$ 734,495	40.12%	$ 3,168,715	80.96%	100.0%
6		**Total Farm:**	**$ 1,830,773**	**$ 2,565,269**	**$ 734,495**	**40.12%**	**$ 3,168,715**	**80.96%**	**100.0%**
7									
8		10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)	$ 7,779,957	$ 11,454,106	$ 3,674,148	47.23%			
9		10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)	$ 1,645	$ 1,882	$ 237	14.41%			
10		**10.01 Small General Service - Under 20 kW**	**$ 7,781,602**	**$ 11,455,988**	**$ 3,674,385**	**47.22%**	**$ 11,383,603**	**100.64%**	**31.8%**
11	EPMC Method 1	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)	$ 19,521,819	$ 26,524,434	$ 7,002,615	35.87%			
12		10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)	$ 57,141	$ 68,314	$ 11,173	19.55%			
13		**10.02 General Service - 20 kW or Greater**	**$ 19,578,959**	**$ 26,592,748**	**$ 7,013,789**	**35.82%**	**$ 24,440,389**	**108.81%**	**68.2%**
14		**10.03 General Service - Time of Use** (Commercial TOU) - (Rates 708, 709, 710)	$ 6,204	$ 8,457	$ 2,253	36.32%	**$ 7,802**	**108.39%**	**0.022%**
15		**Total General Service:**	**$ 27,366,763**	**$ 38,057,193**	**$ 10,690,430**	**39.06%**	**$ 35,831,795**	**106.21%**	**100.0%**
16	**[PROTECTED DATA BEGINS...**								
17									
18									
19									
20									
21									
22									
23									
24									
25									**...PROTECTED DATA ENDS]**
26	EPMC Method 1	11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)	$ 24,947	$ 33,293	$ 8,346	33.46%	$ 33,463	99.49%	37.22%
27		11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)	$ 29,198	$ 46,646	$ 17,448	59.76%	$ 56,439	82.65%	62.78%
28		Total Irrigation:	**$ 54,144**	**$ 79,939**	**$ 25,794**	**47.64%**	**$ 89,902**	**88.92%**	**100.0%**
29									
30		11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)	$ 95,933	$ 98,440	$ 2,507	2.61%			
31		11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)	$ 97,067	$ 99,591	$ 2,524	2.60%			
32	Class Level Increase	11.03 Outdoor Lighting - Signal (Rate 744)	$ 41,803	$ 42,890	$ 1,087	2.60%			
33		11.04 Outdoor Lighting - Street & Area Lighting (Rate 741, 743)	$ 900,453	$ 950,046	$ 49,593	5.51%			
34		11.07 LED STREET and AREA LIGHTING – DUSK TO DAWN (Rate 730, 731)	$ 1,558,539	$ 1,572,920	$ 14,382	0.92%			
35		Total Lighting:	**$ 2,693,795**	**$ 2,763,887**	**$ 70,092**	**2.60%**	N/A	N/A	N/A
36									
37	Class Level Increase	11.05 Municipal Pumping - Secondary Service (Rate 872)	$ 818,301	$ 1,207,388	$ 389,087	47.55%	$ 1,494,535	80.79%	100.00%
38		11.06 Civil Defense - Fire Sirens (Rate 843)	$ 2,553	$ 3,755	$ 1,202	47.09%	N/A	N/A	N/A
39		Total Other Public Authority:	**$ 820,854**	**$ 1,211,143**	**$ 390,289**	**47.55%**	**$ 1,494,535**	**81.04%**	**100.0%**
40									
41	Class Level Increase	14.01 Water Heating - Controlled Service (Rate 191)	$ 688,841	$ 884,120	$ 195,279	28.35%	$ 2,572,417	34.37%	66.54%
42		14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)	$ 601,122	$ 771,533	$ 170,411	28.35%	$ 1,293,615	59.64%	33.46%
43		Total Water Heating:	**$ 1,289,964**	**$ 1,655,653**	**$ 365,690**	**28.35%**	**$ 3,866,034**	**42.83%**	**100.0%**
44									
45	EPMC	14.04 Controlled Service - Interruptible Load Rider CT Metering (Rates 170, 165, 881, 168, 268, 169, 269)	$ 1,154,187	$ 2,067,283	$ 913,096	79.11%	$ 2,100,128	98.44%	37.73%
46		14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)	$ 2,851,749	$ 3,412,273	$ 560,524	19.66%	$ 3,466,488	98.44%	62.27%
47		Total Interruptible:	**$ 4,005,936**	**$ 5,479,556**	**$ 1,473,620**	**36.79%**	**$ 5,566,617**	**98.44%**	**100.0%**
48									
49	Class Level Increase	14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)	$ 164,901	$ 211,104	$ 46,203	28.02%			
50		14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)	$ 114,268	$ 142,110	$ 27,842	24.37%			
51		Total Deferred Load:	**$ 279,169**	**$ 353,213**	**$ 74,045**	**26.52%**	**$ 647,720**	**54.53%**	**100.0%**
52									
53		TOTAL REVENUE:	$ 113,381,480	$ 154,957,208	$ 41,575,728	36.67%	$ 140,459,541	110.32%	

Section No.	Section description	Changes
All sections	General Rules and Regulations and Electric Rate Schedules	• Spacing adjustments were made where appropriate. No symbol was added to the change code column of the rate schedule to signify these changes. Due to the nature of these changes, they will not appear in redline. • Various changes were made throughout to correct capitalization and various typos. These changes do appear in redline but may not be called out in this Schedule 3.
All sections	General Rules and Regulations and Electric Rate Schedules	• In the Header o On all pages increased revision number by one. • In the Footer o Deleted the date located after the words “Approved by order dated”. o Replaced the number located after the words “Case No.” with PU-23-. • Deleted the effective date following the words “EFFECTIVE with bills rendered on and after”
Index	Index	• Updated several Rate Schedule titles to be consistent with our Matrices. • Updated the title of Section 10.02 General Service to (20 kW or greater and less than 200 kW). • Updated the title of Section 10.03 General Service – Time of Use to include (20 kW or greater and less than 200 kW) • Added the NEW Section 13.12 Interim Rate Rider. • Added the NEW Section 13.13 Sales Rider. • Updated the Section 14.04 title with the new combined 14.04 and 14.05 title. • Deleted the Section 14.05 Controlled Service – Interruptible Load Self Contained Metering Rider and changed it to Reserved for Future Use.
1.02	Application for Service	• The word “becoming” has been added to paragraph one for clarification.
1.05	Contracts and Agreements	• Updated the following contracts and agreements: • Electric Service Agreement: o Paragraph 1: Language was added to clarify that Rules and Regulations may be updated and updates will apply, and to notify customers that they can obtain a copy of the Rules and Regulations from the Company. o Paragraph 3: Added language to refer to Excess Expenditures rather than additional costs for clarity. o Paragraph 4: Added language to specify that all mandatory riders apply, as well as voluntary riders

Section No.	Section description	Changes
		the customer chooses to participate in. o Paragraph 5: added language reserving the Company's right to temporarily suspend the delivery of power if necessary to protect public safety. o Paragraph 6: added language clarifying that the contract terminates automatically when a customer discontinues service, but certain payment obligations extend even after the contract has been terminated and added a non-assignment provision. o Paragraph 7 clarified language regarding the purpose of minimum payments for service extension costs. • Irrigation Electric Service Agreement: o Paragraph 1: Language was added to clarify that Rules and Regulations may be updated and updates will apply, and to notify customers that they can obtain a copy of the Rules and Regulations from the Company. o Paragraph 4: Added language to specify that all mandatory riders apply, as well as voluntary riders the customer chooses to participate in. o Paragraph 6: Added language clarifying that the contract terminates automatically when a customer discontinues service, but certain payment obligations extend even after the contract has been terminated and added a non-assignment provision. o Paragraph 7: Removed unnecessary words for clarity. o Paragraph 8: Added language to clarify payments for costs includes Special Facilities charges, identifying the dollar amount of the Company's investment, and updating the two options for payment of the annual fixed charge, changing the first method of calculating the annual fixed charge from 18% of the Company's investment, to the rate in effect at the time the ESA is signed multiplied by the annual amount of the Company's investment paid in seven equal monthly payments, and changing the second method of calculating the annual fixed charge from 3.5% of the Company's investment after prepayment of certain costs, to the rate in effect at the time the ESA is signed multiplied by the annual amount of the Company's

Section No.	Section description	Changes
		investment after prepayment of certain costs, paid in seven equal monthly payments. o Paragraph 9: Deletes the entire paragraph requiring minimum payments. • Outdoor Lighting and Municipal Services Agreement: o Paragraph 1: Language was added to clarify that Rules and Regulations may be updated and updates will apply, and to notify customers that they can obtain a copy of the Rules and Regulations from the Company. o Paragraph 2: Limits the length of the term of the contract to one year, and added language clarifying that the contract terminates automatically when a customer discontinues service, but certain payment obligations extend even after the contract has been terminated and added a non-assignment provision. o Unnumbered paragraph was designated as paragraph 3, and all subsequent paragraphs were advanced by one number. o Paragraph 14 (now 15): Added language to refer to Excess Expenditures rather than additional costs for clarity. • Summary Billing Service Contract: o Customer Authorization: Language was added to clarify that Rules and Regulations may be updated and updates will apply, language was added to notify customers that they can obtain a copy of the Rules and Regulations from the Company, language was added to require accounts to be included be attached to the contract, and language was added to provide for customer either completing a Summary Billing Service Worksheet or most recent copy of all bills. Removes language limiting liability. o Changes by Customer: Reworded to be clearer. o Changes by Company: Removes redundant sentence. o Cancellation (now Termination): Replaces cancellation with termination. o Adds new section titled Liability: Adds language limiting liability that used to be in the Customer Authorization section and relocates them to the new Liability section.

Section No.	Section description	Changes
2.02	Service Classification	• The first paragraph has been updated to clarify that rates designated "General Service" are available to any nonresidential Customer who meets the qualification for the rate. • Two lines at the bottom of page 1 were moved to page 2.
4.14	Combined Metering	• Language has been added to clearly state that to qualify for Combined Metering a Customer must take full requirements service from the Company.
5.01	Extension Rules and Minimum Revenue Guarantee	• Language has been updated in the first paragraph for clarity and an easier read. • Language was added to clarify that if the Company has reason to question whether a customer will cease to take full requirements from the Company, the Company may require the Customer to pay in advance or require any additional conditions of service that are reasonably necessary to protect the Company and its customers.
5.02	Special Facilities	• The tariff is being included in its entirety due to material within the tariff being relocated to other pages. • New language has been inserted on page 2 describing that the charge for Special Facilities will be computed from a formula rate template using inputs from FERC Form 1 with the following expense components; operation and maintenance expense, general and common depreciation expense, taxes other than income tax and distribution depreciation expense. The return component will contain income taxes and return on rate base. • Additionally, on page 2 the following was added: The charge for Special Facilities will be calculated annually and applied to any Electric Service Agreement (ESA) entered into while that rate is in effect and applicable for the life of the ESA. This section will apply unless the company and customer have expressly agreed to different charges in an ESA approved by the Commission. • In the Excess Expenditures section on page 2 "and Operation" was added for clarification. • Expenditure has been changed to Expenditure**s** on page 2 for accuracy. • Capitalized Meter on the last page because it is a term within our Glossary. • Added two new paragraphs on page 5 in the Special Facilities Payments section as follows: Payments required will be made on a non-refundable basis and may be required in advance of construction

Section No.	Section description	Changes
		unless other arrangements are agreed to in writing with the Company. The facilities installed by the Company shall be the property of the Company. Any payment by a requesting party shall not change the Company's ownership interest or rights. Charges for Special Facilities shall be an annual fixed charge of the costs associated with the Excess Expenditures, billed in 12 equal monthly installments, unless another period is specified in the applicable rate schedule or Commission-approved ESA.
8.01	Glossary	• Included the following new Glossary Terms: Account, Full-requirement Customer, Government Unit, Megawatt (MW), Meter Multiplier, Non-Standby Service Customer, Partial-requirements Customer, Seasonal Customer, Single-phase, Standby Service Customer, Tariff (Tariff Schedules), and Three-phase. • Capitalized several terms because they are Glossary Terms. • Due to these changes, material within the tariff has been relocated to other pages.
9.01	Residential Service	• Updated the Rate Box to include a Facilities Charge per Month • Capitalized Residential and Customer because they are Glossary Terms. • Updated the rates. • Inserted a new paragraph at the bottom of page 2 describing the Determination of Facilities Charge as follows: **DETERMINATION OF FACILITIES CHARGE**: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities.
9.02	Residential Demand Control Service (RDC)	• Updated the Rate Box to include a Facilities Charge per Month • Capitalized Winter because it is a Glossary Term. • Updated the Rate Box to clarify that the demand charge is per month. • Updated the rates. • Inserted a new paragraph at the bottom of page 2 describing the Determination of Facilities Charge as follows: **DETERMINATION OF FACILITIES CHARGE:** An amount to be paid by the Customer in a fixed monthly amount for distribution facilities.
9.03	Farm Service	• Updated the Rate Box to clarify that the demand charge is per month. • Updated the rates.

Section No.	Section description	Changes
		• Added a new page 2 to this tariff. • Inserted a new paragraph on page 2 describing the Determination of Facilities Charge as follows: **DETERMINATION OF FACILITIES CHARGE:** An amount to be paid by the Customer in a fixed monthly amount for distribution facilities.
10.01	Small General Service (Under 20 kW)	• Updated the Rate Box to include a Facilities Charge per Month • Updated the rates. • Capitalized Demand on page 2 because it is a Glossary Term. • Inserted a new paragraph at the bottom of page 2 describing the Determination of Facilities Charge as follows: **DETERMINATION OF FACILITIES CHARGE**: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities sized on the basis of the Customer's design (rather than metered) Demand.
10.02	General Service (20 kW or Greater)	• Updated the title to include "20 kW or greater and less than 200 kW". • Updated the Rate Code box at the top of page 1 closing our current General Service Rates to New Customers and adding new General Service Rate Codes for customers going forward on these rates with the new Terms and Conditions included on page 2. • Updated the Application of Schedule section on page 1 with a 200 kW limit. • Updated the Rate Box to include a Demand Charge per kW (minimum 20 kW) charge. • Updated the rates. • Added additional language to the Terms and Conditions as follows: The Customer may remain on this schedule as long as the Customer's maximum monthly Billing Demand does not meet or exceed 200 kW for more than two of the most recent 12 months. If the Customer achieves an actual Billing Demand of 200 kW or greater for the third time in the most recent 12 months, the Customer will be placed on the Large General Service schedule (Section 10.04) in the next billing month. The Customer is also eligible for service on the Large General Service Time of Day (Section 10.05) but must direct the company to their applicable rate option.

<table>
<tr><th>Section No.</th><th>Section description</th><th>Changes</th></tr>
<tr><td>10.03</td><td>General Service - Time of Use</td><td>Updated the title to include “20 kW or greater and less than 200 kW”.
Updated the Rate Code box at the top of page 1 closing our current General Service – Time of Use Rates to New Customers and adding new General Service – Time of Use Rate Codes for customers going forward on these rates with the new Terms and Conditions included on page 2.
Updated the Application of Schedule section on page 1 with a 200 kW limit.
Updated the rates.
Added additional language to the Terms and Conditions as follows: The Customer may remain on this schedule as long as the Customer's maximum monthly Billing Demand does not meet or exceed 200 kW for more than two of the most recent 12 months. If the Customer achieves an actual Billing Demand of 200 kW or greater for the third time in the most recent 12 months, the Customer will be placed on the Large General Service schedule (Section 10.04) in the next billing month. The Customer is also eligible for service on the Large General Service Time of Day (Section 10.05) but must direct the company to their applicable rate option.
Updated the definition of Declared, Intermediate and Off-Peak periods by season.</td></tr>
<tr><td>10.04</td><td>Large General Service</td><td>Updated the Application of Schedule section on page 1 to direct our customers to the details in our Terms and Conditions.
Updated the Rate Box to clarify that the demand charge is per month.
Updated the rates.
Added a new Terms and Conditions section on page 3 as follows.
A Customer with a Billing Demand of greater than 200 kW for 12 consecutive months will be required to take service under the Large General Service (Section 10.04) or Large General Service schedule – Time of Day (Section 10.05).
The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW for more than two of the most recent 12 months. Customers on this schedule whose maximum monthly Billing Demand are less than 200 kW for less than 10 of the most recent 12 months, may take service on Section 10.02 or</td></tr>
</table>

Section No.	**Section description**	**Changes**
		10.03. If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule.
10.05	Large General Service - Time of Day	• Added a new page 5 to this tariff. • Updated the Application of Schedule section on page 1 to direct our customers to the details in our Terms and Conditions. • Changed the term Shoulder to Mid-Peak throughout the entire tariff. • Updated the Rate Box to clarify that the demand charge is per month. • Updated the rates. • Added a new Terms and Conditions section on page 3 as follows: o A Customer with a Billing Demand of greater than 200 kW for 12 consecutive months will be required to take service under the Large General Service schedule (Section 10.04) or Large General Service schedule – Time of Day (Section 10.05). o The Customer must remain on this schedule if its maximum monthly Billing Demand meets or exceeds 200 kW for more than two of the most recent 12 months. Customers on this schedule whose maximum monthly Billing Demand are less than 200 kW for less than 10 of the most recent 12 months, may take service on Section 10.02 or 10.03. If the Customer meets the criteria to take service on Section 10.02 or 10.03, they must direct the Company to the applicable rate schedule. • Updated the definitions of On-Peak, Mid-Peak and Off-peak periods by season. • Added a NEW Optional Trial Service at the bottom of page 4 continuing onto the new page 5 as follows: o Customers may elect Time of Day service for a trial period of three months. o If a Customer chooses to return to non-time of day service after the trial period, the Customer will pay a charge of $60.00 for removal of time of day metering equipment. o If a Customer chooses to change from this schedule after the three-month trial period, the customer must notify the Company within 15 days after the trial period ends. Otherwise, the Customer will remain on this schedule for the minimum of

Section No.	Section description	Changes
		one year as described in the General Rules and Regulations Section 1.02. o The Company will remove the time of day metering equipment and switch the customer to a different applicable rate within 45 days of receipt of written notice of termination of the trial period.
11.01	Standby Service	• Added a new page 9 to this tariff. • Updated the rates. • Changed the term Shoulder to Mid-Peak throughout the entire tariff. • Added Supplemental Demand Summer and Winter Rates for both Option A – Firm Standby and Option B – Non-Firm Standby. • Added definitions for Determination of Billing Demand and Adjustment for Excess Reactive Demand on page 5 as follows: **DETERMINATION OF BILLING DEMAND:** The Billing Demand shall be the Metered Demand adjusted for Excess Reactive Demand. **ADJUSTMENT FOR EXCESS REACTIVE DEMAND**: For billing purposes, the Metered Demand shall be increased by 1 kW for each whole 10 kVar of measured Reactive Demand in excess of 50% of the Metered Demand in kW. • Updated the Backup Service hours at number 2 of the Terms and Conditions on page 5. • Capitalized Season on page 5 and Distribution on page 7 because they are Glossary terms. • Corrected the spelling of manages in the MISO definition on page 7. • In the Definitions and Useful Terms section on page 7, Contracted Backup Demand has been updated to include the following: The Contract Backup Demand is set by mutual agreement of the Customer and Company to electric capacity levels sufficient to meet the customer's standby load. If the Company determines the capacity levels sufficient for the customers' standby load have changed, within two billing cycles, the Contracted Backup Demand will require review by both Company and Customer, for both billing and resource planning purposes. Any billing adjustments will be retroactive to the month the Company notified the Customer.

Section No.	Section description	Changes
		• In the Definitions and Useful Terms section on page 8, the following language was **removed** from Non-Standby Service Customer section: For Large General Service or Large General Service – Time of Use Customers, a Special Minimum Demand may apply. • In the Definitions and Useful Terms section on page 9, the following Special Minimum Demand definition was **removed**: Special Minimum Demand is a special Demand calculation that the Company may use at its option for the Large General Service or Large General Service – Time of Day Customers. The terms are outlined in Sections 10.04 and 10.05. • In the Definitions and Useful Terms section on page 9, non-Company was changed to Customer in the Standby Service Customer term. • In the Definitions and Useful Terms Section on page 9, in the Supplemental Service term, the following language was **removed**: Except for determination of Demand, Supplemental Service shall be provided under Standard Rate Schedule 10.05. • Updated the definitions of On-Peak, Mid-Peak and Off-Peak periods by seasons.
11.02	Irrigation Service	• Updated the rates. • Clarified in the Rate Boxes to see the Facilities Charge section of the tariff for details. • Updated the Facilities Charge section on page 2 to reference Section 5.02, Special Facilities, for the annual fixed charge. • Updated the definitions of Declared, Intermediate and Off-Peak periods by seasons.
11.03	Outdoor Lighting - Energy Only - Dusk to Dawn	*Rate changes only*
11.04	Outdoor Lighting - Dusk to Dawn (CLOSED TO NEW INSTALLATIONS)	• Updated the rates. • Capitalized Energy on page 3 because it is a Glossary term. • Removed “Interim” from the header on page 3.
11.05	Municipal Pumping Service	*Rate changes only*
11.06	Civil Defense - Fire Sirens	• Updated the rates. • Capitalized Distribution Facilities and Distribution because they are Glossary terms.

Section No.	Section description	Changes
11.07	LED Street and Area Light - Dusk to Dawn	• Updated the rates. • Capitalized Customer on page 1 because it is a Glossary term.
12.00	**Purchase Power Riders - Applicability Matrix**	• Updated the title for consistency in our Rate Books with other jurisdictions. • Updated Rate Schedule titles to be consistent with our Index. • Updated the title of Section 10.02 General Service to (20 kW or greater and less than 200 kW). • Updated the title of Section 10.03 General Service – Time of Use to include (20 kW or greater and less than 200 kW)
12.01	Small Power Producer Rider Occasional Delivery Energy Service	*No changes – Not included in this filing*
12.02	Small Power Producer Rider Time of Delivery Energy Service	*No changes – Not included in this filing*
12.03	Small Power Producer Rider Dependable Service	*No changes – Not included in this filing*
13.00	**Mandatory Riders – Availability Matrix**	• Correction to the title including in the headers. • Added a new page 3 to this tariff. • Updated several Rate Schedule titles to be consistent with our Index. • Updated the title of Section 10.02 General Service to (20 kW or greater and less than 200 kW). • Updated the title of Section 10.03 General Service – Time of Use to include (20 kW or greater and less than 200 kW) • Added our NEW Interim Rate Rider. • Added our NEW Sales Rider. • Updated rows for Section 14.04 and 14.05 to show them combined as Section 14.04. Section 14.05 is now Reserved for Future Use. • A third page was added to increase the size of our tables for easier reading. The Mandatory Riders remain on page 2 and the Voluntary Riders have been moved to a new page 3. Headings were added to the moved Voluntary Riders table on page 3. • Various changes have been made to the applicability indicators for these Mandatory Riders. Following a thorough review, it was determined these updates were necessary.

Section No.	Section description	Changes
		Civil Defense – Fire Sirens: Applies if the Rider is a Percent of Bill. *Water Heating Control Rider*: Due to the Credit on this rider these were changed to "May Apply". *Section 14.05* – Are being removed because this tariff is now Reserved for Future Use. *Economic Development Rate Rider:* These do not apply due to this being a discount.
13.01	Energy Adjustment Rider	• The title has been updated to indicate that this rider is identified on the bill as Fuel & Purchase Power. • Capitalized Kilowatt and Kilowatt-hour on page 1 because they are Glossary terms. • The Energy Adjustment Factor service categories on page 1 have been updated to properly describe our Controlled Service categories. • Section 14.05 has been removed from the Controlled Service Interruptible service category because it has been combined with Section 14.04. • Section 14.06 has been moved to the newly titled Controlled Service Deferred Load category. • MISO on page 2 has been correctly identified as Midcontinent Independent System Operator. • At number 8 on page 2 the narrative has been updated to state as follows: All revenues and associated costs attributable to Asset-based Sales Margins, as defined below and in the amount calculated as described below, shall be included in the Energy adjustment calculation described in this schedule. • The following statement was added to the Asset-based Sales Margin description at the top of page 3: One hundred percent of these actual revenues and costs shall be included in the energy adjustment rider as they are incurred. • On page 3, how the amount of the Asset-based Sales Margin credit was previously determined has been removed from this tariff. • A new number 9 has been inserted on page 3 as follows: 9. The costs of fuel and reagents resulting from steam and water sales and the revenues from steam and water sales shall be included in the energy adjustment rider. • Our standard Mandatory and Voluntary Riders paragraph directing customers to our matrices at Section 12.00, 13.00 and 14.00 has been added to this tariff as follows: **MANDATORY AND VOLUNTARY RIDERS:** The

Section No.	Section description	Changes
		amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.
13.02	Reserved for Future Use	*No changes – Not included in this filing*
13.03	Reserved for Future Use	*No changes – Not included in this filing*
13.04	Renewable Resource Cost Recovery Rider	*No changes – Not included in this filing*
13.05	Transmission Cost Recovery Rider	• The Application of Rider section on page 1 has been updated to include a reference to our matrices. • The Rate Box has been updated to include Section 11.01, Standby Service, in our Large General Service group (a) and in the Controlled Service group (b) a change has been made to show the combining of Sections 14.04 and 14.05.
13.06	Generation Cost Recovery Rider	• The Application of Rider section on page 1 has been updated to include a reference to our matrices. • Capitalized Customer's because it is a Glossary term. • Updated the rate to zero. • Page 2 is being included to correct an indention issue within the Forecasted retail revenues paragraph near the middle of the page.
13.07	Reserved for Future Use	*No changes – Not included in this filing*
13.08	Environmental Cost Recovery Rider	*No changes – Not included in this filing*
13.09	Reserved for Future Use	*No changes – Not included in this filing*
13.10	Reserved for Future Use	*No changes – Not included in this filing*
13.11	Advanced Meter and Distribution Technology (AMDT) Cost Recovery Rider	• The title has been changed to Metering & Distribution Technology (MDT) Cost Recovery Rider. • The Rate Code box on page 1 and the Rate box on page 2 have been updated to properly describe our Controlled Service categories. • Capitalized Customer on page 1 because it is a Glossary term. • Updated Section 14.05 in the Controlled Service Interruptible – Self Contained category of the Rate Box to 14.04. This is necessary due to combining Section 14.04 and 14.05 into one Rate Schedule and Section 14.05 now being Reserved for Future Use. • Moved Section 14.06 (Controlled Service Deferred Load Rider) to the newly titled Controlled Service Deferred Load category.

Section No.	Section description	Changes
13.12	Interim Rate Rider	*Introduced with Interim Rate Schedules – No changes.*
13.13	NEW Sales Adjustment Rider	• This is a new rider designed to address the impacts of changes on base rate revenues and base rate jurisdictional cost allocations. This is being introduced due to the significant changes in sales between rate cases.
14.00	**Voluntary Riders - Availability Matrix**	• Corrected the title in the header. • Updated several Rate Schedule titles to be consistent with our Index. • Updated the title of Section 10.02 General Service to (20 kW or greater and less than 200 kW). • Updated the title of Section 10.03 General Service – Time of Use to include (20 kW or greater and less than 200 kW) • Updated the columns for Section 14.04 and 14.05 to show them combined as Section 14.04. Section 14.05 is now Reserved for Future Use. • A correction was made to the indicators in the 14.13 Economic Development Rate Rider – Large General Service column.
14.01	Water Heating Control Rider	• Updated the rates. • Removed "Interim" from the header on page 2. • A Determination of Facilities Charge definition has been added on page 2 as follows: **DETERMINATION OF FACILITIES CHARGE**: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities. • Removed "Interim" from the header on page 2.
14.02	Real Time Pricing Rider	• Added a new page 6 to this tariff. • Added clarification to the change to the Facilities Demand Charge, reactive demand applicability in the light of the customers CBL demand adjustments at page 2, 5 and 6. • Added language describing the conditions of a potential CBL increase at page 5. • Capitalized Energy, Demand, Reactive Demand and Billing Demand throughout this tariff because they are Glossary terms. • Removed "Interim" from the header on pages 2 – 6.
14.03	Large General Service Rider	• "Facilities Demand" has been added to items to be determined in the Electric Service Agreement in the Electric Service Agreement section on page 1. • Capitalized Commercial on page 1 and 2 because it is a Glossary term. • Removed "Interim" from the header on page 5 and 6.

Section No.	Section description	Changes
14.04	Controlled Service - Interruptible Load CT Metering Rider (Large Dual Fuel)	• Added a new page 4 to this tariff. • Section 14.05, Controlled Service – Interruptible Load Self-Contained Metering Rider (Small Dual Fuel) has been included with this Section 14.04, Controlled Service – Interruptible Load CT Metering Rider (Large Dual Fuel). These Rate Schedules have been combined. • Added clarification of CT with or without ancillary load. • Added to the Self-Contained Metering and CT Metering without Ancillary Load Rate Boxes the following penalty clarification language: During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above. • Updated the rates. • Capitalized Demand, Meter, Facilities Charge Demand, and Billing Demand because they are Glossary terms.
14.05	Controlled Service - Interruptible Load Self-Contained Metering Rider (Small Dual Fuel)	• This Rate Schedule is being cancelled and reserved for future use. A Cancelled version and a Reserved for Future Use version are included. (Section 14.05, Small Dual Fuel, is being combined with Section 14.04, Large Dual Fuel as described above.)
14.06	Controlled Service - Deferred Load Rider (Thermal Storage)	• Updated the rates. • Added to the Rate Box the following penalty clarification language: During the Penalty Period, kWhs used will be measured and billed at the Energy Charge and Penalty listed above. • Removed “Interim” from the header on page 3.
14.07	Fixed Time of Service Rider	• Updated the title to include: (Commonly identified as Fixed TOS) • Updated the rates. • Added the following definition of Determination of Facilities Charge: **DETERMINATION OF FACILITIES CHARGE**: An amount to be paid by the Customer in a fixed monthly amount for distribution facilities sized on the basis of the Customer’s design (rather than metered) demand.
14.08	Air Conditioning Control Rider (**Cool***Savings*)	• Updated the rates. • Updated the Rate Boxes to describe our new Extended Summer Cooling Season. • Updated the Summer Season hours in our Terms and Conditions section on page 2 to describe our new Extended Summer Cooling Season hour.
14.09	Voluntary Renewable Energy Rider	• *No changes – Not included in this filing*

Section No.	Section description	Changes
	(**Tail***Winds)*	
14.10	WAPA Bill Crediting Program Rider	• *No changes – Not included in this filing*
14.11	Reserved for Future Use	• *No changes – Not included in this filing*
14.12	Bulk Interruptible Service Application and Pricing Guidelines	• Updated the title of the Fixed Charge Determination section to Facilities Charge Determination. • Changed the definition of this Facilities Charge Determination to reference Rules and Regulations Section 5.02 as follows: A fixed charge will be established to recover the Company's investment related costs. Customers served under this rate shall pay a fixed charge according to the language set forth in Section 5.02, Special Facilities.
14.13	Economic Development Rate Rider	• Corrected the numbering error in the Terms and Conditions section. • Inserted “and Voluntary” in the new Terms and Conditions No. 5. • Our standard Mandatory and Voluntary Riders paragraph directing customers to our matrices at Section 12.00, 13.00 and 14.00 has been added to this tariff at page 3 as follows: **MANDATORY AND VOLUNTARY RIDERS:** The amount of a bill for service will be modified by any Mandatory Rate Riders that must apply or Voluntary Rate Riders selected by the Customer, unless otherwise noted in this rate schedule. See Sections 12.00, 13.00 and 14.00 of the North Dakota electric rates for the matrices of riders.
15.00	**Retail Electric Service to Communities**	• Corrected Churchs Ferry and Rocklake communities to their proper name.