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-17-

Exhibit___

RATE DESIGN

Direct Testimony and Schedules of

DAVID G. PRAZAK

November 2, 2017

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME AND OCCUPATION.

A. My name is David G. Prazak. I am employed by Otter Tail Power Company (OTP) as its Supervisor of Pricing and Tariff Administration.

Q. PLEASE SUMMARIZE YOUR QUALIFICATIONS AND EXPERIENCE.

A. I have over 27 years of experience in the energy industry and over 20 years of experience in the Regulatory Administration Department in Pricing and Rate Design. My current duties include managing the design and implementation of retail pricing strategies for rate schedule and contract pricing, including rates and rate design and tariff administration. My qualifications and experience are more fully described on Exhibit___(DGP-1), Schedule 1.

II. PURPOSE AND OVERVIEW OF DIRECT TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to: (1) describe the rate structure objectives that were used in developing the proposed rates; (2) explain the role of marginal costs in OTP's rate design; (3) describe the proposed rate design for OTP's rate schedules and riders; (4) introduce new rate designs, and (5) support 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, the role of marginal costs in rate design and OTP's fixed charge proposals. In Section IV, I identify our rate design proposals for each customer class. Section V

identifies new rate proposals, Section VI identifies tariff changes other than rates. Section VII provides my conclusion.

III. RATE DESIGN PROCESS

A. Overall Rate Structure Objectives

Q. WHAT ARE THE RATE STRUCTURE OBJECTIVES THAT GUIDE OTP'S RATE DESIGN?

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.
- 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. Intra-Class Revenue Allocation

Q. PLEASE SUMMARIZE 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 the structure of 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 methodology 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 marginal cost study and its application to the rate design process. The first step in that process is to allocate to rate classes the class revenue responsibilities developed by OTP Witness Ms. Gina S. Ice, as described in her Direct Testimony. This is done using the EPMC methodology. I then develop the individual rate components (energy, demand, fixed) for each rate class, based on marginal costs, which are designed to recover the overall revenue requirement.

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 I focus on the development of individual rate components further in this section and in Section IV, below.

Q. DOES OTP USE BOTH EMBEDDED AND MARGINAL COSTS IN ITS RATE DESIGN?

A. Yes. OTP's revenue requirement and the class revenue responsibilities recommended by Ms. Ice are calculated to recover the cost of service, which is measured by embedded costs. 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. 2018 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 2018 Marginal Cost Study, 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 NH Regulatory Consulting, LLC to develop a marginal cost study covering the period 2018-2022 applicable to service in our three jurisdictions (the 2018 Marginal Cost Study). The 2018 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 2018 Marginal Cost Study to make sure it does in fact reflect OTP's marginal costs. A copy of the 2018 Marginal Cost Study is included as Exhibit___(DGP-1), Schedule 2.

Q. HOW ARE THE RESULTS OF THE 2018 MARGINAL COST STUDY APPLIED TO THE RATE DESIGN PROPOSAL?

A. The 2018 Marginal Cost Study provides an accurate calculation of current marginal costs. But those marginal costs are significantly different than those calculated in the marginal cost study filed in our last rate case (the 2008 Marginal Cost Study). In order to avoid an abrupt reflection of the new marginal costs in our proposed rate design, OTP tempered the 2018 Marginal Cost Study results when allocating class revenue responsibilities to rate classes and in the development of individual rate components.

Q. WHAT ARE THE MAIN DIFFERENCES IN THE RESULTS OF THE 2018 MARGINAL COST STUDY AND THE RESULTS OF THE 2008 MARGINAL COST STUDY?

A. All marginal energy costs have decreased, and seasonal marginal capacity costs have undergone significant change. For example:

- Annual, summer and winter marginal energy costs are lower in the 2018 Marginal Cost Study than they were in the 2008 Marginal Cost Study. Both annual marginal energy costs and winter marginal energy costs have decreased by 67 percent and 64 percent, respectively, while summer marginal energy costs have declined 71 percent.
- Annual marginal capacity costs have increased 55 percent, but summer marginal capacity costs have increased nearly 90 percent. At the same time, winter marginal capacity costs have increased 16 percent.

Q. WHAT IS DRIVING THESE CHANGES?

A. There are two general drivers. First, marginal costs should reflect the wholesale market place. 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 low energy prices and rising capacity costs for the near-term.

The second driver is based on a change in assumptions behind the 2008 and 2018 Marginal Cost Studies. The 2008 Marginal Cost Study reflected OTP's resource planning approach at that time. That approach required OTP to build its system to meet its system peak, which occurs during the winter. The 2018 Marginal Cost Study, however, reflects OTP's current resource planning approach. The current resource planning approach is based upon OTP's obligation to meet its MISO obligations, which are measured as OTP's load coincident with MISO's peak. MISO's peak occurs during the summer. This shift from a planning approach focused on winter peak to one focused on summer peak has a significant impact on marginal capacity costs.

Q. ARE THERE OTHER REASONS TO USE MODIFIED RESULTS FROM THE 2018 MARGINAL COST STUDY WHEN DESIGNING RATES?

A. Yes. MISO is currently considering changes to its resource planning construct that would move away from a summer-only peak and move towards a dual (i.e. summer and winter) peak structure. As discussed above, the MISO capacity construct has a significant impact on marginal costs, so this potential change could impact marginal costs over the next several years. Reflecting this change now allows us to design rates in a way that better reflects marginal costs during the period in which the rates will be in effect.

Q. HOW DID YOU MODIFY THE 2018 MARGINAL COST STUDY RESULTS?

A. We utilized the 2018 Marginal Cost Study to create a baseline of marginal costs and then made the following adjustments:

- Use a modified average of marginal energy and capacity costs of years 2018-2022, as OTP anticipates rates to be in place for at least 3 years.
- Moderate the generation capacity estimates in 2018-2022 by allocating 60 percent of their value to summer, and allocate the remaining 40 percent to winter.

Q. HOW DID YOU DECIDE ON A 60-40 ALLOCATION OF GENERATION CAPACITY VALUES?

A. This allocation was a judgment decision that balances the current MISO capacity construct (i.e. 100 percent of generation value in the summer, 0 percent in winter), the expected MISO capacity construct (i.e., less than 100 percent of generation value in the summer and greater than 0 percent in the winter), and the current levels of demand-capacity charges in OTP's rate schedules.

Q. HOW WILL YOUR 60-40 PROPOSAL IMPACT RATE DESIGN?

A. Rate classes without demand charges will see relatively lower increases in summer rates that would have occurred using the unmodified 2018 Marginal Cost Study results. The 60-40 proposal also results in slight increases in winter rates. All else being equal, rate classes with separate energy and capacity charges will be designed with essentially the

same energy charge relationships as in the unadjusted marginal cost study, but with lower increases in summer demand charges and increases in winter demand charges.

Q. WHAT ARE THE BENEFITS IN THIS CASE OF USING MODIFIED RESULTS OF THE 2018 MARGINAL COST STUDY?

A. The modifications I propose approximate the expected MISO capacity construct in the near term. Further, even if the 2018 Marginal Cost Study results were not modified as I propose, the pure marginal cost price signals would have been diluted at the individual rate design level because the pure price signals would have been too extreme to implement in a single case. Finally, by using this approach, all rates will be designed based on my proposed allocation, thereby providing improved consistency across all classes and important price signals for expected generation seasonal capacity values.

2. Proposed Intra-Class Revenue Allocation

Q. HOW ARE CLASS REVENUE RESPONSIBILITIES ALLOCATED TO RATE CLASSES?

A. When the customer class has two or more rate classes, the class revenue responsibilities developed by Ms. Ice generally are allocated to the individual rate classes based on the EPMC methodology.[1]

Q. DO THE CLASS REVENUE RESPONSIBILITIES DEVELOPED BY MS. ICE INCLUDE FUEL COSTS?

A. Yes. The class revenue responsibilities developed by Ms. Ice include amounts currently in base rates for fuel.[2] OTP Witness Mr. Stuart D. Tommerdahl explains that OTP is proposing to move all fuel costs out of base rates and recover those costs entirely through the Energy Adjustment Rider. Exhibit___(DGP-1), Schedule 3 shows the proposed intra-

[1] 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 current Residential customer class has two rates; a general service rate and a demand-controlled rate, each with their own applicability requirements.

[2] Direct Testimony of Ms. Gina S. Ice, Table 8.

class revenue allocations, while Exhibit___(DGP-1), Schedule 4 shows the proposed intra class revenue allocations including and excluding fuel costs from base rates.

Q. WHAT IS THE EPMC METHODOLOGY?

A. The EPMC methodology allocates the class revenue responsibilities to rate classes based on each rate class's marginal cost revenues. Marginal cost revenues for a rate class are determined by multiplying the marginal cost (modified as discussed above) times the rate class billing determinants. Schedule 4 describes total marginal cost revenues by customer and rate class.

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

A. Yes. The table below provides a simplified example of the "pure" version of the EPMC methodology, 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 methodology is aligned with two of our rate structure objectives – efficiency and gradualism. Using marginal cost-based revenues to allocate revenue from customer classes to rate classes sets efficient revenue targets for rates within a class.

Q. HAS THE EPMC METHODOLOGY BEEN USED AND ACCEPTED IN OTP'S JURISDICTIONS?

A. Yes. The Commission approved OTP's use of the EPMC methodology in OTP's last general rate case (Case No. PU-08-862). The Minnesota Public Utilities Commission and the South Dakota Public Utilities Commission approved the use of the EPMC methodology in OTP's last general rate cases in each of those jurisdictions (MN PUC Docket No. E017/GR-15-1033 and SD PUC Docket No. EL10-011).

Q. IS OTP PROPOSING TO USE A MODIFIED VERSION OF THE EPMC METHODOLOGY?

A. Yes. I recommend using a modified version of the EPMC methodology to allocate class revenues to rate classes.

Q. WHY IS OTP PROPOSING TO USE A MODIFIED VERSION OF THE EPMC METHODOLOGY IN ALLOCATING CLASS REVENUES TO RATE CLASSES?

A. The pure EPMC method would have resulted in dramatic changes in rate class revenue responsibilities, which is inconsistent with our rate structure objectives of gradualism and rate continuity. Using the modified version of the EPMC methodology allowed us to balance the efficiency benefits of marginal cost-based rates with other important rate structure objectives.

Q. PLEASE DESCRIBE HOW OTP APPLIED THE EPMC METHODOLOGY.

A. OTP utilized three EPMC approaches to allocate class revenues for those classes that have more than one rate class (except for Other Public Authority class, discussed below). The three approaches have different levels of gradualism from the pure or strict application of EPMC, thereby mitigating the abruptness of rate changes.

1. Method 1 – This method modifies the results from strict application of EPMC within a class and was applied to four of the six customer classes. 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. Ice for the customer class (excluding fuel); 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 objective of gradualism.

2. Method 2 – This method utilizes a blended variation between Method 1 and a strict application of EPMC within a customer class. This method was applied to two customer classes. The purpose of this method is to bring the rate classes within the customer class into better alignment with cost responsibility. Under this method, we continue to gradually reduce the distance between revenue increase allocation within the Rate Class.

3. Method 3 – This is an iterative method that uses a blended variation between two rate classes within the Lighting customer class. It is an iterative continuation of Method 2, with the goal to reach a reasonable target as close as possible to the overall class percent change.

Q. WHICH EPMC METHODOLOGY DID YOU USE FOR EACH CUSTOMER CLASS?

A. The table below identifies which EPMC method for each customer class.

Table 2
Summary of EPMC Methods for Customer Classes with Multiple Rate Classes

Customer Class	**EPMC Method**
Residential	Method 2
Farm	N/A
General Service	Method 2
Large General Service	Method 1
Irrigation	Method 1
Outdoor Lighting	Method 3
Water Heating Control	N/A
Other Public Authority	N/A
Controlled Service - Interruptible	Method 1
Controlled Service - Deferred	Method 1

For further details on individual rate EPMC results, see Schedule 4.

Q. HOW DID YOU ALLOCATE THE OTHER PUBLIC AUTHORITY CUSTOMER CLASS REVENUES TO RATE CLASSES?

A. Other public authority class revenues were allocated to each rate class uniformly at the same percentage increase as recommended by Ms. Ice for the customer class overall. An EPMC approach was not required because a majority of the revenues from this class are from one rate class.

C. Development of Individual Rate Components

Q. WHAT IS THE NEXT STEP IN THE RATE DESIGN PROCESS AFTER ALLOCATING CUSTOMER CLASS REVENUES TO RATE CLASSES?

A. After class revenues are allocated to rate classes, the individual rate components for each class are developed.

Q. WHAT ARE THE COMPONENTS OF CUSTOMER RATES?

A. There are three general rate components: energy charges, demand or capacity charges, and fixed charges. The rate design for different rate classes may or may not include each component. For example, the standard Residential rate currently does not include a separate demand or capacity charge because omitting such charges makes the rate structure simpler and avoids the need to install more costly metering that has the capability to measure demand. In contrast, the Residential Demand Control rate is a more complicated rate and does employ a more costly meter to measure demand. And for further contrast, the proposed Residential Time of Day rate utilizes three charge periods per season versus the other rates with only a single charge period per season.

1. Fixed Charges Defined

Q. WHAT ARE FIXED CHARGES?

A. Fixed charges are monthly per-customer charges that do not vary with usage. They typically take the form of customer charges and local facilities charges. OTP's rate schedules include both customer charges and facilities charges, though for most classes, the facilities charge is set at $0.00.

Q. WHAT COSTS ARE TYPICALLY RECOVERED THROUGH FIXED CHARGES?

A. Fixed charges are typically used to recover costs of service that do not vary with electricity consumption after the customer connects to the grid. These costs include marginal customer-related expenses, such as installing, operating and maintaining the meter and service drop, conducting meter reading and billing activities, and providing marketing or other informational services.

Fixed charges can also recover the cost of connecting to the local distribution system, including the required transformers, secondary lines or local primary lines that may need to be added or expanded to accommodate the customer's expected maximum demand over the life of the facilities. The type of distribution connection policy in place will determine the local facilities costs that are to be recovered in rates as opposed to up-front. If customers within the class are relatively homogeneous, the local facilities costs may be recovered in a per-customer monthly fixed charge, calculated on the basis of the class average kW of design demand, as opposed to the individual customer's design demand.[3] Distribution facilities costs are recovered as a monthly fixed charge in the 2018 Marginal Cost Study.

Q. PLEASE PROVIDE ADDITIONAL DISCUSSION OF WHAT COSTS ARE CLASSIFIED AS CUSTOMER-RELATED IN THE 2018 MARGINAL COST STUDY.

A. Marginal customer-related costs are costs that vary with the number of customers on the system. Marginal customer costs vary by customer type within the class but do not vary with on-going changes in usage. The following costs are classified as customer-related in the 2018 Marginal Cost Study: annualized investment and operation and maintenance (O&M) expenses on meters and service drops; customer account expenses (such as

[3] A "design demand" or "contract demand" is equivalent to a capacity that is reserved in the transformer for all customers connected to it. It is thus appropriate for a per-contract kW charge, or else as part of the fixed customer charge assuming that there is enough heterogeneity in the peak demands within the class. A daily demand charge measures actual metered demand, and recognizes that demand reductions can free up space for other customers at the high voltage distribution system, and therefore it is appropriate for recovery in volumetric charges. If there are different customer densities in the service territory, such as rural and urban areas, rural local facilities costs may be higher than urban and in that case, it may be best to have a monthly facilities cost per kW that differs by area type to avoid subsidization of rural areas by urban customers, unless the line extension policy already corrects for that. A facility charge may not be feasible by OTP at this time, however, since it would require metering capability that is able to register non-coincident peak demand.

meter-reading, billing, and collection); and customer service and informational expenses such as call centers. Certain supervisory costs and administrative and general expenses associated with growth in customer-related costs are also classified as customer-related. Ultimately, because these costs do not vary with usage, they are appropriately recovered in a fixed monthly component of the rate.

2. Proposed Fixed Charges

Q. WHAT CUSTOMER CHARGES IS OTP PROPOSING IN THIS CASE?

A. The table below shows the proposed customer charge component of the fixed charges.

Table 3
Proposed Customer Charges
($/Month)

Class	Present	Proposed
Residential	$8.00	$17.70
Residential – Demand Control	$18.38	$20.10
Farm Service – Single Phase	$12.00	$17.40
Farm Service – Three Phase	$12.00	$17.40
Small General Service	$13.00	$24.90
General Service (Secondary)	$12.00	$31.90
General Service – Time of Use	$16.00	$219.00
Large General Service (Secondary)	$40.00	$215.90
Large General Service – Time of Day (Primary)	$60.00	$282.00
Irrigation – Option 1	$1.00	$24.30
Irrigation – Option 2	$5.00	$24.30
Outdoor Lighting – Metered	$2.00	$2.00
Outdoor Lighting – Non-metered	$0.00	$0.00
Municipal Pumping (All)	$4.00	$26.50
Civil Defense	$1.00	$1.22
Water Heating	$1.00	$4.00
Controlled Service – Interruptible- Large #1	$4.00	$20.20
Controlled Service – Interruptible- Large #2	$5.00	$20.20
Controlled Service – Interruptible - Small	$2.00	$8.50
Deferred Load Service	$3.00	$8.80
Fixed Time of Service (Secondary)	$1.50	$6.70

Q. DID OTP CONSIDER MARGINAL COST IN SETTING THE PROPOSED CUSTOMER CHARGES?

A. Yes. Exhibit___(DGP-1), Schedule 5 compares present customer charges to marginal customer-related costs from the 2018 Marginal Cost Study. OTP recommends bringing customer charges for all classes into better alignment with marginal costs.

Table 4
Proposed Customer Charge as Percentage of Marginal Cost – Secondary Service
($/Month)

Class	2018 Marginal Cost	Proposed Customer Charge	Proposed Customer Charge as Percent of 2018 Marginal Cost	Present Customer Charge as Percent of 2008 Marginal Cost
Residential	$17.70	$17.70	100.0%	79%
Residential – Demand Control	$20.18	$20.10	99.6%	110%
Farm Service – Single Phase	$17.42	$17.40	99.9%	97%
Farm Service – Three Phase	$17.42	$17.40	99.9%	97%
Small General Service	$24.94	$24.90	99.8%	74%
General Service (Secondary)	$31.91	$31.90	100.0%	45%
General Service TOU	$219.05	$219.00	100.0%	6%
Large General Service (Secondary)	$215.95	$215.90	100.0%	16%
Large General Service – Time of Day (Primary)	$282.08	$282.00	100.0%	20%
Irrigation – Option 1	$24.33	$24.30	99.9%	4%
Irrigation – Option 2	$24.33	$24.30	99.9%	2%
Outdoor Lighting – Metered	$0.30	$2.00	667%	47%
Outdoor Lighting – Non-metered	$0.30	$0.00	0.0%	0%
Municipal Pumping (All)	$26.55	$26.50	99.8%	16%
Civil Defense	$26.55	$1.22	4.6%	4%
Water Heating	$5.59	$4.00	71.6%	15%
Controlled Service - Interruptible- Large #1	$20.27	$20.20	99.7%	12%

Class	2018 Marginal Cost	Proposed Customer Charge	Proposed Customer Charge as Percent of 2018 Marginal Cost	Present Customer Charge as Percent of 2008 Marginal Cost
Controlled Service - Interruptible- Large #2	$20.27	$20.20	99.7%	15%
Controlled Service – Interruptible-Small	$20.27	$8.50	41.9%	14%
Deferred Load Service	$8.86	$8.80	99.3%	17%
Fixed Time of Service	$6.71	$6.70	99.9%	9%

Q. IS IT IMPORTANT FOR FIXED CHARGES TO BE ALIGNED WITH MARGINAL COSTS?

A. Yes. As discussed in more detail below, aligning fixed charges with marginal costs promotes fairness among customers and encourages the efficient use of resources.

a) Intra-Class Equity

Q. WHY DOES ALIGNING FIXED CHARGES WITH MARGINAL COSTS PROMOTE FAIRNESS AMONG CUSTOMERS?

A. When fixed charges are set below marginal cost, the balance of the costs that should be recovered through fixed charges 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 aligning fixed charges with marginal costs, OTP's proposed rate design makes important steps to improve customer equity.

Q. SHOULD FIXED CHARGES BE KEPT UNREASONABLY BELOW MARGINAL COSTS AS A MEANS OF ADDRESSING AFFORDABILITY FOR RESIDENTIAL CUSTOMERS?

A. No. Low usage is not always correlated with low income and some low-income customers are in fact, high electricity users. Keeping fixed charges unreasonably below marginal cost helps Residential customers with usage below the class average usage, but there is nothing in this approach that means the benefits go to those that need them. Ultimately, keeping fixed charges unreasonably below marginal cost is a very inefficient means of helping low income customers, as the benefits flow to both low income and

higher income customers. Direct assistance such as the Low Income Home Energy Assistance Program (LIHEAP) is a more reasonable approach for addressing affordability.

Q. DO YOU HAVE ANY DATA SHOWING THAT AN ARTIFICIALLY LOW FIXED CHARGE IS NOT AN APPROPRIATE MEANS OF ADDRESSING AFFORDABILITY FOR OTP'S LOW-INCOME RESIDENTIAL CUSTOMERS?

A. Yes. The table below shows the average usage of OTP's low-income Residential customers[4] is greater than the average usage of the OTP Residential population overall and is greater than the average usage of the OTP non-low income Residential customer population. Further, OTP's low-income customers are more likely than the OTP Residential population at large to fall into the group that pays more than their fair share of the cost of service when fixed charges are kept artificially low. All of this means that more low-income Residential customers are harmed by keeping fixed charges below marginal cost than are helped.

Table 5
Comparison of Residential Service (Section 9.01) Usage
(2016 Usage Data)

	Residential Customers	Low-Income Customers	Non-Low Income Customers
Average Monthly Usage (kWh / Month)	786	1,184	774
Percentage of Customers with Usage in Excess of 750 kWh / Month[5]	41%	58%	40%
Number of Customers with Usage in Excess of 750 kWh / Month	15,241	617	14,624

Additional details regarding the usage characteristics of the Residential class are available in Exhibit___(DGP-1), Schedule 6. At least for OTP's customers, there does not appear to be a strong relationship between income and usage.

[4] For purposes of this Direct Testimony, low-income is defined as those customers receiving LIHEAP assistance.
[5] The true breakeven point for full recovery of marginal costs is the class average, or approximately 786 kWh. For analytical purposes, we have used 750 kWh as the breakeven point.

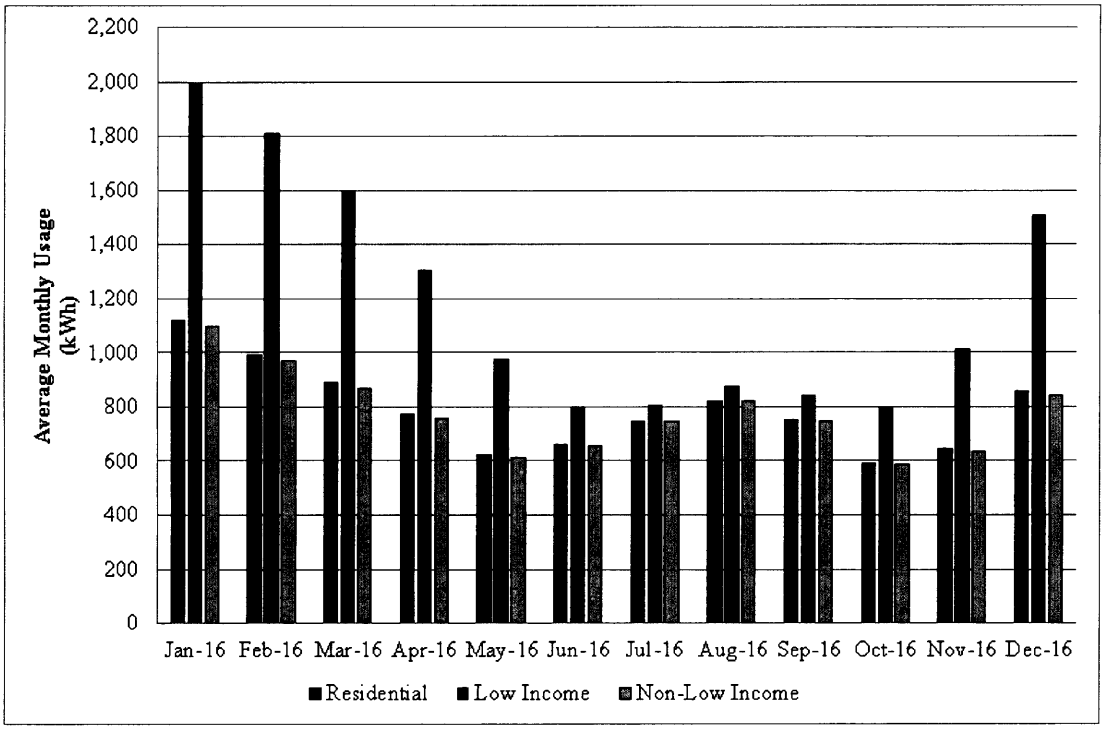
Q. ARE THERE OTHER ELEMENTS OF OTP'S CUSTOMER POPULATION THAT MAKE INTRA-CLASS EQUITY ESPECIALLY IMPORTANT?

A. Yes. Our service area is predominantly rural and many customers rely on electricity for heating. 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 fixed charges are kept below marginal cost. The mere fact that these customers live where they do and have limited heating options means they are uniquely harmed by keeping fixed charges at unreasonably low levels.

Q. IS THERE ANY DATA THAT INDICATES LOW-INCOME CUSTOMERS ARE PARTICULARLY RELIANT ON ELECTRICITY FOR HEATING PURPOSES?

A. Yes. The figure below compares average monthly usage for OTP's overall Residential customer population and the low-income and non-low income subgroups. Low-income customers' winter usage is significantly higher than the usage of the Residential population overall and of non-low income customers during winter months. The differential in usage being so much more pronounced in the winter months indicates that the low-income population relies more on electricity for heating purposes than does the non-low income and Residential populations overall.

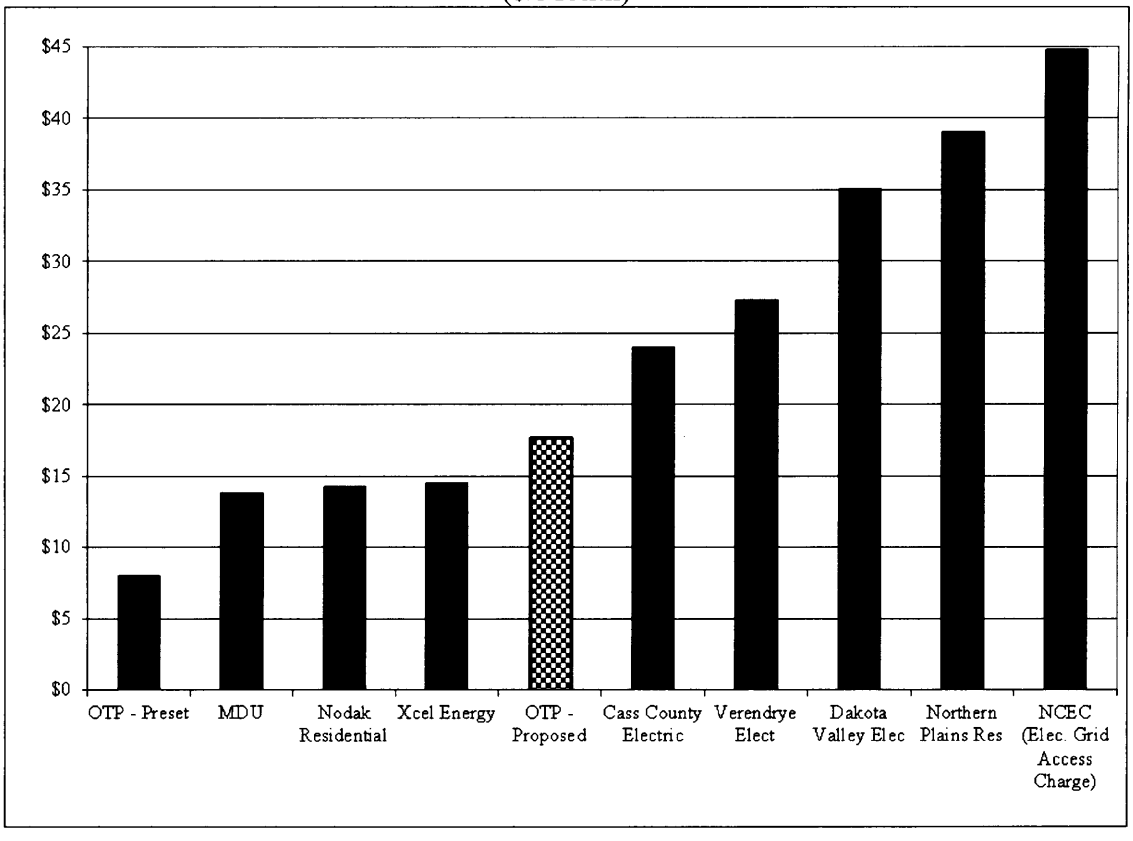
Figure 1
Comparison of Monthly Residential Service (Section 9.01) Customer Usage
(2016 Usage Data)



Q. HOW DOES OTP'S PROPOSED RESIDENTIAL CUSTOMER CHARGE COMPARE TO CUSTOMER CHARGES PAID BY OTHER, NON-OTP CUSTOMERS?

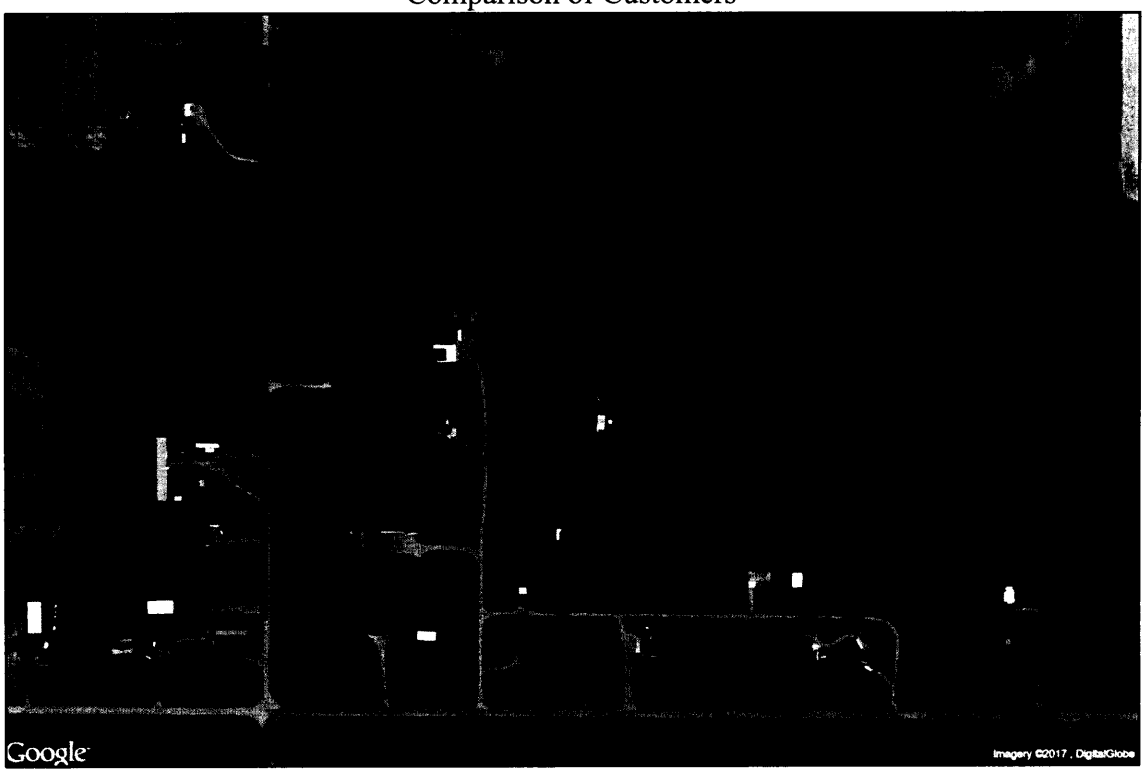
A. The figure below compares OTP's present and proposed Residential customer charges to those of other North Dakota investor owned utilities and cooperatives that serve customers in close proximity to the areas served by OTP. OTP's proposed Residential customer charge is moderate when compared to other Residential customer charges.

Figure 2
Comparison of Residential Fixed Charges
($/Month)



Importantly, many of our customers have neighbors that pay significantly higher fixed charges than what we propose. For example, the figure below shows a group of premises: some served by OTP and others served by Northern Plains Electric Cooperative (inside the marked box). The OTP customers currently pay a monthly customer charge of $8.00; the Northern Plains Electric Cooperative customers pay a monthly customer charge of $39.00.

Figure 3
Comparison of Customers



Q. ARE THERE COST-BASED REASONS FOR OTP'S FIXED CHARGES TO BE HIGHER THAN OTHER NORTH DAKOTA INVESTOR OWNED UTILITIES?

A. Yes. As discussed above, fixed charges are intended to recover costs that do not change when a customer uses more (or less) electricity or demand after connecting to the grid. Some of these costs have little relationship to the number of customers served. For example, every utility, no matter the size, needs a billing system. A larger utility can spread the costs of that billing system across more customers, which, all else being equal, would lead to lower fixed charges. OTP is smaller than North Dakota's other investor owned utilities and therefore has fewer customers over which to spread customer-related costs.

Also, some of the costs recovered through fixed charges depend on customer density. Meter reading would be an example: a more densely packed system will have lower meter reading costs, again, all else being equal. Unlike North Dakota's other investor owned utilities, OTP does not serve North Dakota's major cities.

Q. ARE THERE OTHER REASONS FOR OTP TO HAVE HIGHER FIXED CHARGES THAN LARGER, MORE URBAN UTILITIES?

A. Yes. With a less densely populated system, OTP must deploy more transformers per customer than do more urban utilities. Also, we deploy larger transformers (and the minimum load our system is designed to handle is larger) given our customers' use of electricity for heating purposes. All else being equal, more and larger transformers would lead to higher fixed costs that are recovered through fixed charges.

Q. ARE THERE ANY OTHER FACTORS THAT RELATE TO THE FAIRNESS OF OTP'S PROPOSED FIXED CHARGES?

A. Yes. OTP's *rate design proposal* does not change the total amount to be collected from customers – only the balance between amounts collected through the fixed charges and the amounts collected through the energy charge. Increases in fixed charges are offset by reductions in energy charges. Customers with usage that is equal to the class average will see no change in the total bill as a result of the fixed charge proposal.

b) Conservation and Self-Generation

Q. DO OTP'S PROPOSED FIXED CHARGES COMPROMISE EFFICIENT CONSERVATION INCENTIVES?

A. No. OTP's proposed fixed charges do not harm efficient conservation initiatives. By using marginal costs to design rates, OTP's overall rate structure includes price signals that allow customers to compare the incremental cost of service (though averaged over the season) with the incremental value of using more energy. Such price signals encourage the efficient use of resources and provide a sound basis for customers to assess the value of conservation.

Q. WHAT IS THE IMPORTANCE OF THE WORD "EFFICIENT" IN THE PHRASE "EFFICIENT CONSERVATION INCENTIVES"?

A. Public policy does not support conservation at any cost. We want to encourage economically efficient conservation efforts. Setting rates that reflect the marginal cost of

service helps send appropriate price signals that ultimately incentivize economically efficient conservation.

Q. PLEASE EXPLAIN HOW ARTIFICIALLY LOW FIXED CHARGES DO NOT ENCOURAGE ECONOMICALLY EFFICIENT CONSERVATION.

A. When fixed charges are set too low, costs that are unrelated to usage are more likely to be shifted to volumetric charges. Artificially high volumetric prices, all else being equal, incentivize customers to reduce usage below optimal levels or self-generate. Such reductions result in an inefficient use of the capacity that is available. If customers self-generate due to excessive volumetric charges, that decision represents uneconomic bypass of the system because the total cost of service for all customers (those with self-generation and those without self-generation) will increase.

Q. ARE THERE BETTER WAYS TO PROMOTE CONSERVATION?

A. Yes. OTP's Water Heating – Controlled Service Rider is a very effective way to achieve energy conservation goals and promote more optimal patterns of usage. A well designed direct load control program keeps marginal cost principles in mind so that customers' benefits (in the form of bill reductions) are aligned with avoided cost to the utility over time. Marginal cost-based rates that signal the higher cost of service in the hours in the day when electricity costs are the highest or when capacity is strained so that load reductions provide the highest value to the utility and the system overall.

Dynamic rates (such as Critical Peak Pricing, or Peak Time Rebate) can provide the strongest conservation signals. Less dynamic but still useful for conservation purposes are marginal-cost based time of use (TOU) rates, which may include either a super peak kWh charge or an on-peak demand charge to reflect peak marginal energy and capacity costs, including marginal generation capacity, transmission and high-voltage distribution costs.

IV. 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 to eliminate the winter declining block and make rate level adjustments. This rate includes a monthly customer charge, a minimum bill equal to that customer charge, and a flat seasonally differentiated energy charge. The energy charges are set at levels necessary to meet the revenue requirement not satisfied by the customer charge. The proposed energy charges, although purposely above marginal cost, provide an efficient price signal for Residential customers. The proposed customer charge is 100 percent of marginal cost, as discussed above. Marginal costs for facilities were developed based on customer usage, a proxy for design demand, tied to transformer and other customer-related distribution equipment.

Table 6

Comparison of Current and Proposed 9.01 Residential Rate and Marginal Costs

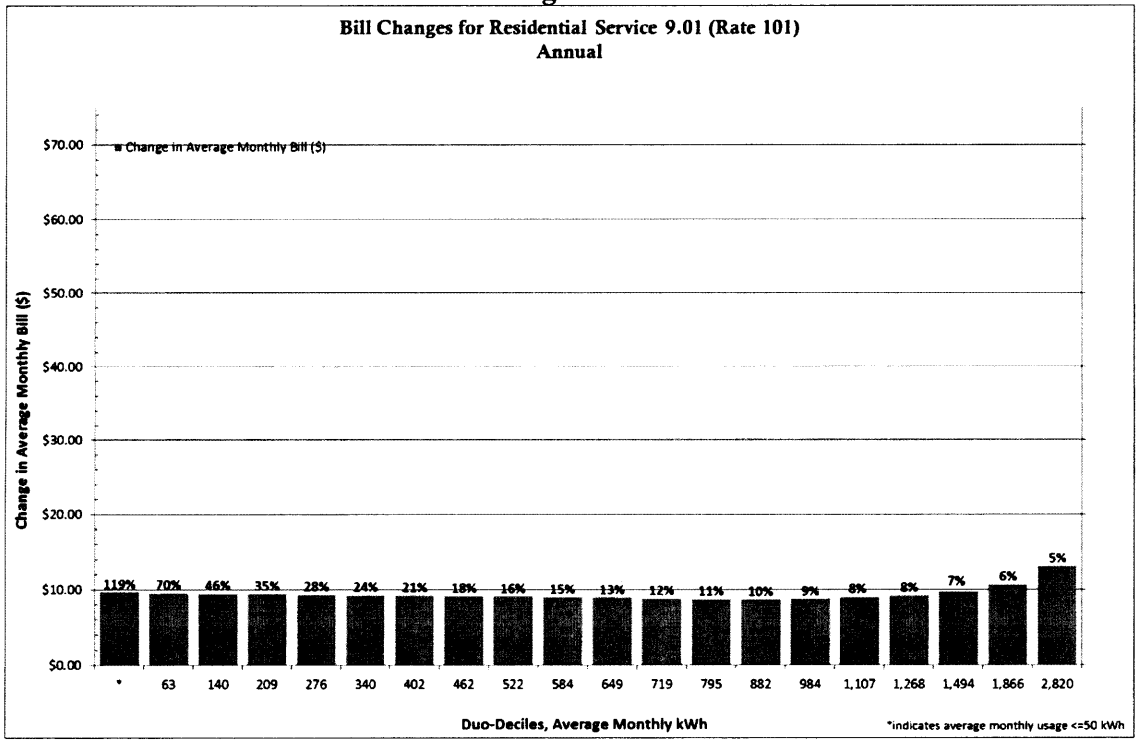
Residential Service	Section 9.01						
						Energy Charge	
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per month			per kWh	
					All Year	Summer	Winter
Current Rate	$8.00	Customer + Facilities			**First 1000**	$0.08444	$0.07863
					Excess	$0.08444	$0.07173
Seasonal Customer Charge	$32.00			AC Credit	-$7.00		
				Water Heating Credit	-$4.00		
Proposed Rate	$17.70	Customer + Facilities	$0.00		**ENERGY**	$0.07851	$0.05951
Seasonal Customer Charge	$70.80		$0.00				
				AC Credit	-$8.25		
				Water Heating Credit	-$8.00		
Marginal Costs	**$17.70**	**< 1,800 kWhs**	**$11.69**		**All kWh**	**$0.06065**	**$0.04103**
		>= 1,800 kWhs	**$46.11**				

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

A. To analyze bill 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 that customer's bill under current rates and under proposed rates for each rate schedule within each class, using 2018 forecasted billing information (OTP's Test Year). We then created bar charts showing the average monthly bill changes (dollar amounts and percentage) for the duo-deciles 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 the bar chart for Residential customers shows, most of the Residential 9.01 customers will see annual average monthly impacts of less than $10.

Figure 4



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

A. OTP's proposed Residential Controlled Demand (RCD) rate retains the current rate design. As shown in the table below, the proposal continues with seasonal energy charges above marginal cost to achieve the embedded revenue requirement for this class. The demand charges for summer and winter are set at equal rates. The flat demand charge proposal deviates from marginal costs because the rate design is in transition. This rate is designed for reducing demand in the winter when OTP's system peaks. As discussed above, however, OTP's capacity obligation under MISO's Module E construct is based upon summer peak. Therefore, setting seasonal demand charges equally signals to the customer the value of demand in both seasons and the importance of responding to demand signals. The current demand charges are levied with a 12-month ratchet, using only the winter season. The facilities charges are not included as a separate charge in the rate design. Customer Charge is at 99.6 percent of the marginal cost.

Table 7
Comparison of Current and Proposed 9.02 Residential Controlled Demand and Marginal Costs

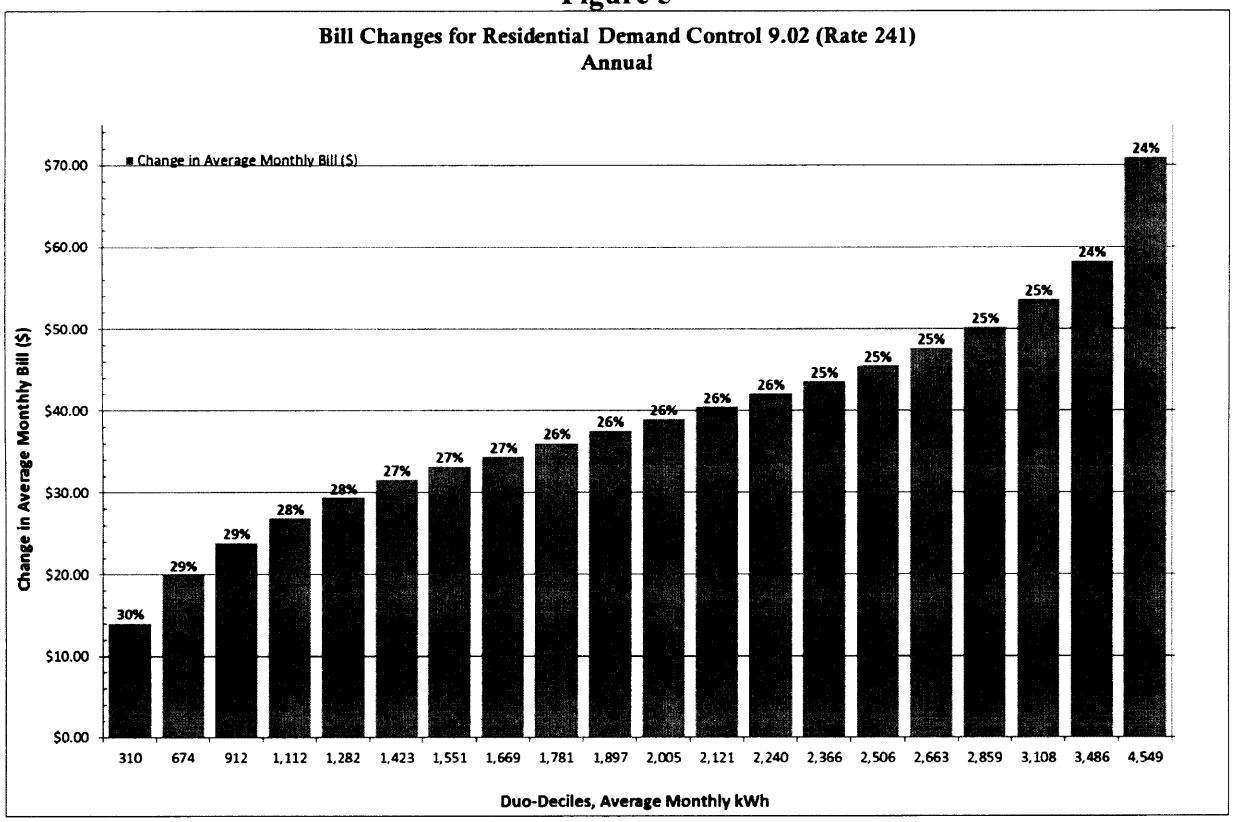
RESIDENTIAL DEMAND CONTROL SERVICE	Section 9.02								
	Customer Charge per month	Minimum Bill per month		Facilities Charge per month		Charge per kWh Summer	Charge per kWh Winter	Demand Charge per kW per mo. Summer per 12-mo. max monthly	Demand Charge per kW per mo. Winter per 12-mo. max monthly
Current Rate									
Customer Charge per Month:	$18.38	Cust. + Facility + Demand Charges	Facilities Charge per Month All Customers	$0.00	All kWh:	$0.04627	$0.04671	$6.52	$2.63
Proposed Rate						Summer	Winter	per 12-mo. max monthly	per 12-mo. max monthly
Customer Charge per Month:	$20.10	Cust. + Facility + Demand Charges	Facilities Charge per Month	$0.00	All kWh:	$0.04852	$0.03752	$8.00	$8.00
Marginal Costs	$20.18		Annual max. monthly kWh Urban Rural	$11.69 $46.11		Energy Only: Summer $0.02511	Winter $0.02674	Capacity Only: Summer $25.36	Winter $10.41

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

A. The bill impacts, shown in the figure below, are fairly consistent in percentage terms, ranging from 24 to 30 percent, across groups of customers with increasing average monthly energy consumption. For comparison purposes, the 2018 Test-Year average

customer usage on Residential Controlled Demand is greater than the Residential Service Customer by a factor of about 2.6.

Figure 5



B. Farm Class

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

A. Yes. In the table below, the energy charges for summer and winter are above marginal cost. The customer charges are set at 100 percent of marginal cost. My rate structure proposal is to collapse the facilities charges into a single charge for both single and three-phase service. Facilities charges for single phase and three phase are set at levels necessary to meet the revenue requirement not satisfied by the energy charges.

Table 8

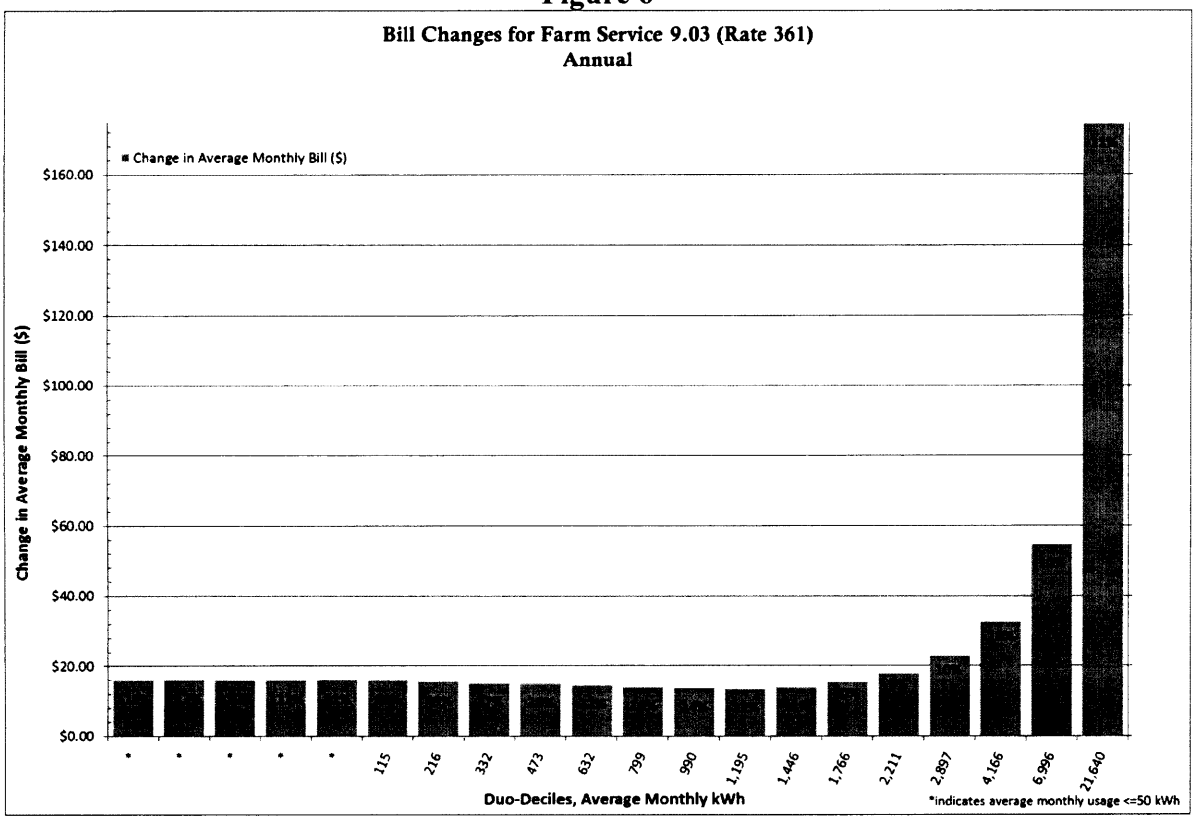
Comparison of Current and Proposed 9.03 Farm Service and Marginal Costs

FARM SERVICE	Section 9.03						
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per kVA of Transformer			Energy per kWh Summer	Energy per kWh Winter
Current Rates	$12.00	Cust + Fac	Single-Phase Charge per Mo.	$0.00	First 1600 kWh	0.07642	0.06971
			3-Phase Charge per Mo.		Excess	0.06495	0.05925
			Overhead <= 25kVa	$3.37			
			Overhead > 25kVa	$3.93			
			Underground <= 25kVa	$9.39			
			Underground > 25kVa	$10.78			
Proposed	$17.40	Cust + Fac	Facilities Charge per kVA of Transformer				
			Single-Phase , per Month	$10.00	All kWh	$0.07000	$0.05100
			3-Phase, per Month	$20.00			
Marginal Costs	$17.42	Cust + Fac	Single-Phase Monthly Charge	$ 46.65	All kWh	$0.09005	$0.04103
			3-Phase Monthly Charge	$ 49.63			
			Overhead <= 25kVa	$ 34.64			
			Overhead > 25kVa	$ 62.61			
			Underground <= 25kVa	$ 56.63			
			Underground > 25kVa	$ 100.37			

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

A. As shown in the figure below, approximately 80 percent of customers (the first 16 duo-deciles) see annual average monthly bill increases of less than $20 per month. The remaining four duo-deciles (20 percent of the customers) have increases of approximately 10 to 11 percent.

Figure 6



C. General Service Class

Q. WHAT RATE SCHEDULES ARE YOU PROPOSING TO INCLUDE 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 (Currently Section 10.04, proposed to be Section 10.03).

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

A. As shown in the table below, OTP proposed energy charges for the Small General Service (Under 20 kW) above marginal cost. I also propose a customer charge at 99.9 percent of marginal cost. The minimum bill is equal to the sum of the customer charge and facilities charge.

Table 9

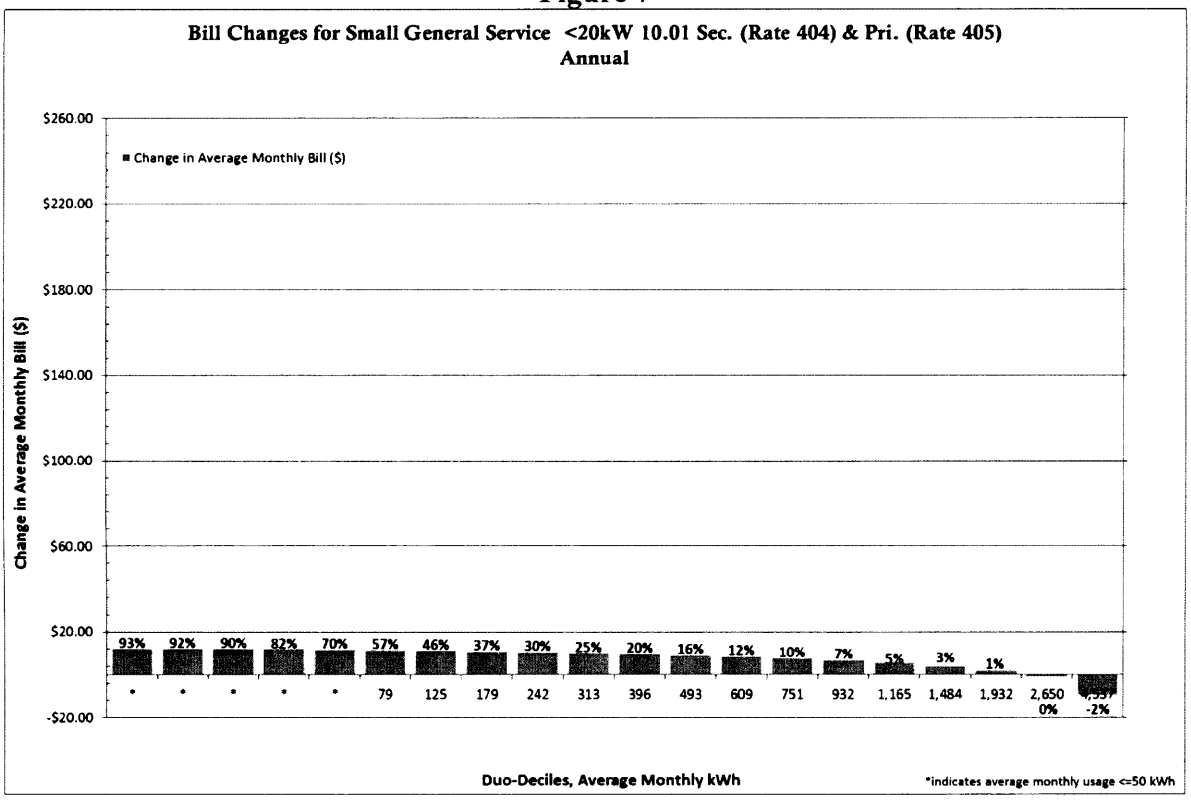
Comparison of Current and Proposed 10.01 Small General Service (Under 20 kW) Rate and Marginal Costs

SMALL GENERAL SERVICE Under 20 KW	Section 10.01				
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge per annual max. kW per month	Energy Charge per kWh Summer	Winter
Current Rate GS					
Secondary Service	$13.00	Customer Charge	NA	$0.08509	$0.07762
Primary Service	$13.00	Customer Charge	NA	$0.08471	$0.07725
Proposed GS Rate					
Secondary Service	$24.90	Customer Charge	NA	$0.07371	$0.05471
Primary Service	$24.90	Customer Charge	NA	$0.07103	$0.05203
Marginal Costs					
Secondary Service	$24.94		$45.63	$0.06065	$0.04103
Primary Service	$24.94		$30.58	$0.05845	$0.03931

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

A. The average annual monthly bill increases for the Small General Service (Under 20 kW) rate range from a negative 2 to 93 percent. About 90 percent of the class (represented by the first 18 duo-deciles) will see an increase of less than $10.00/month. The rest will see some savings.

Figure 7



Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR 10.02 GENERAL SERVICE (20 KW OR GREATER).

A. In this case, we have introduced a differentiation between the customer charges for primary and secondary service in order to reflect the difference in marginal cost of service between the two. As shown in the table below, the proposed customer charges and facilities charges are set approximately at cost. The proposed energy charge is set above marginal energy costs to meet the revenue requirement not satisfied by other charges. The minimum bill is the sum of the customer and facilities charges.

Table 10

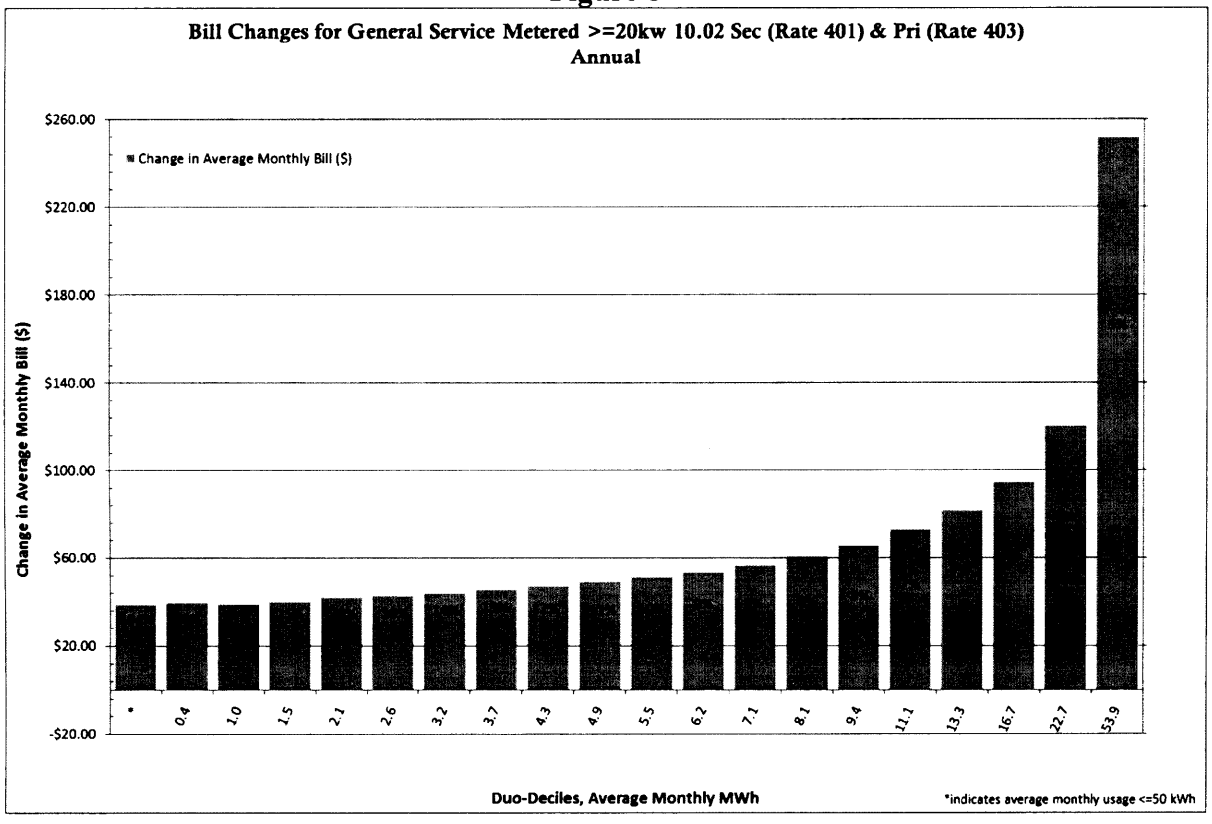
Comparison of Current and Proposed 10.02 General Service (20 kW or Greater) Rate and Marginal Costs

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	$12.00	Cust. + Facilities Charge	$0.52	$0.08213	$0.07492	$ -	$ -
Primary	$12.00	Cust. + Facilities Charge	$0.38 20 kW Minimum	$0.08176	$0.07456	$ -	$ -
Proposed Rate							
Secondary	$31.90	Cust. + Facilities Charge	$0.98	**$0.07268**	**$0.06168**	$ -	$ -
Primary	$21.30	Cust. + Facilities Charge	$0.65 20 kW Minimum	**$0.07005**	**$0.05905**	$ -	$ -
Marginal Costs							
Secondary	$31.91	Cust. + Facilities Charge	$0.98	$0.08065	$0.04103	$ -	$ -
Primary	$21.38	Cust. + Facilities Charge	$0.65	$0.05645	$0.03931	$ -	$ -

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

A. The figure below shows about 50 percent of customers have annual average monthly bill increases of 10 percent or less. The dollar-level impacts are fairly consistent for most of the duo-deciles because of fixed charge increases.

Figure 8



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

A. The proposed rate, shown in the table below, 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 200 hours per year to approximately 100 hours per year. The proposed shoulder and off-peak energy charges are set above 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. The rate includes a customer charge and sets the minimum bill at the sum of the customer charge, the facilities charge, and a minimum 20 kW demand (same concept as in the Large General Service, 10.04).

We are also proposing a slight modification to the classification of peak and off-peak hours under this rate by extending the time of day concept to Sundays.

Table 11
Comparison of Current and Proposed 10.03 General Service Time of Use
Rate and Marginal Costs

GENERAL SERVICE - TIME OF USE	Section 10.04							
	Customer Charge per month	Minimum Bill per month	Facilities Charge per per KW 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 seasonal max kW	
Seasonal Energy and Demand with Peak, Shoulder, Off Peak	$16.00	Cust+Fac. +min. Demand	$0.52	*Declared	$0.20663	$0.13679	NA	NA
				Intermediate	$0.07004	$0.07098	$2.51	$2.90
				Off-peak	$0.04149	$0.04295	$0.00	$0.00
				*Declared energy rates include some Capacity costs.				
Proposed							per seasonal max kW	
Seasonal Energy and Demand with Peak, Shoulder, Off Peak	$219.00	Cust+Fac. +min. Demand	$0.98	*Declared	$0.48071	$0.18066	NA	NA
				Intermediate	$0.03294	$0.03379	$3.44	$5.12
				Off-peak	$0.02180	$0.02363	$0.00	$0.00
				*Declared energy rates include some Capacity costs.				
				*Declared energy rates include some Capacity costs.				
Marginal Costs		Declared energy rates include 60%/40% capacity costs adjustment.			Marginal Energy			Marginal Capacity
					$0.48071	$0.18066 Declared	$0.00	$0.00
					$0.02991	$0.03069 Interm.	$3.34	$4.79
	$219.05		$0.96		$0.01980	$0.02146 Off	$0.10	$0.33

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

A. There is only one customer on this rate; therefore we cannot present the duo-decile chart. Bill impacts will depend on each customer's usage patterns (season, level, and frequency of use by each customer in the three different periods (on, shoulder, and off-peak)). Therefore, there is a wide range of impacts that could be further influenced by how customers respond to these new prices. Finally, individualized bill analysis could compromise the privacy of the customer.

D. Large General Service Class

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

A. There are five rates within the Large General Service Class: Large General Service (Section 10.04), Large General Service Time of Day (Section 10.05) and Standby Service (Section 11.01), Real-Time Pricing Rider (Section 14.02), and a Large General Service Rider (Section 14.03).

Q. PLEASE DESCRIBE YOUR OVERALL RATE DESIGN PROPOSAL FOR THE LARGE GENERAL SERVICE CLASS.

A. OTP's proposal for the Large General Service Class removes the LGS Rate declining block rates in both summer and winter and otherwise continues the current designs, with adjustments to rate levels, and minor language changes.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 10.04 LGS RATE.

A. The proposed LGS rate continues with single block seasonal demand but removes the declining block energy charges. These charges are based on marginal costs. As shown in the table below, seasonal energy charges are set above marginal costs, with summer energy costs slightly lower than winter energy costs, consistent with the results of the 2018 Marginal Cost Study. Seasonal demand charges are set below marginal costs, with the differential between summer and winter demand charges increasing from proposed levels to reflect the difference in seasonal marginal costs

The facilities charge continues to vary by size of customer (in terms of maximum annual kW) and by voltage level. These charges are approximately 100 percent of marginal cost. The customer charge continues to move closer to marginal cost, and set at 99.9 percent. The minimum bill is set at the sum of the customer, facility, and demand charges. The proposed rate retains the minimum demand at 80 kW.

Table 12

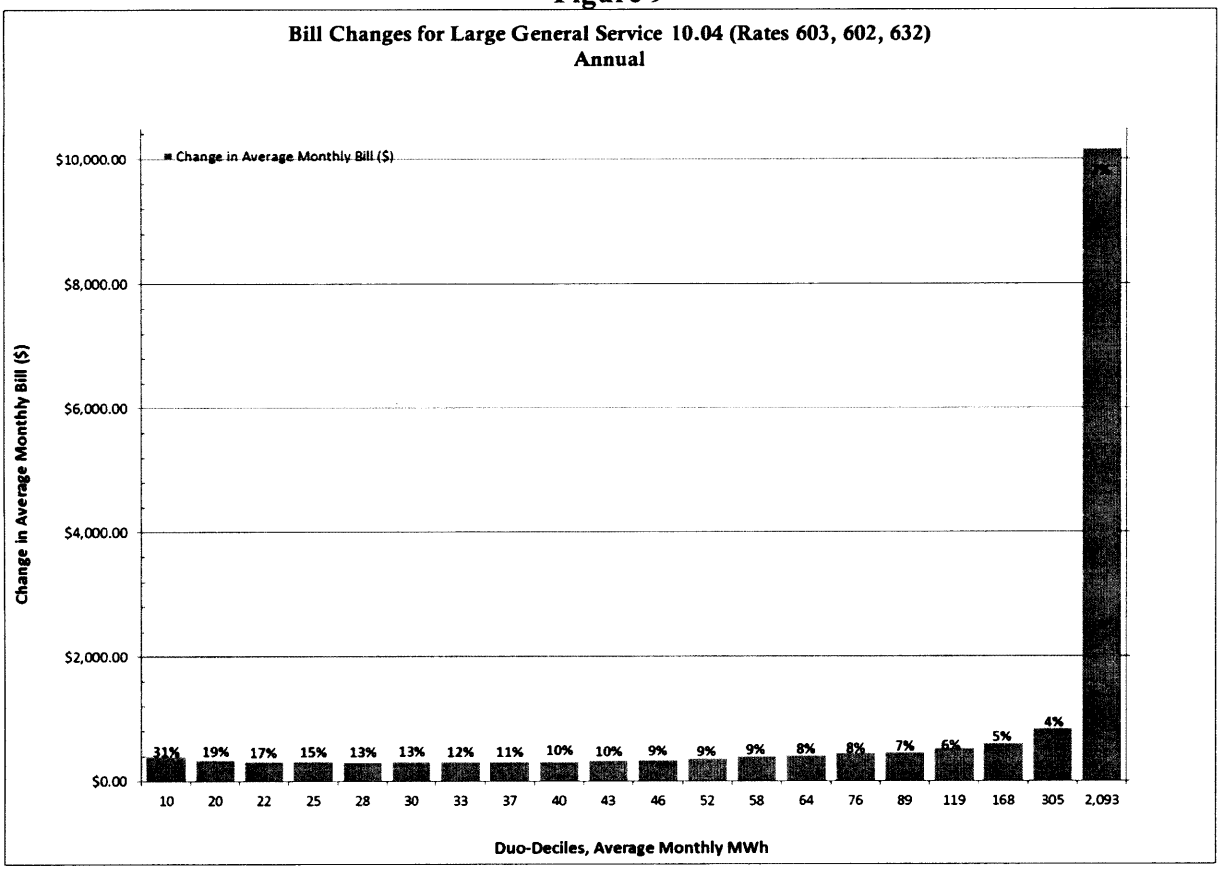
Comparison of Current and Proposed 10.04 Large General Service Rate and Marginal

LARGE GENERAL SERVICE	Section 10.03							
	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	$40.00	Cust+Fac+Demand		First 700,000	$0.05115	$0.05165	$7.29	$5.61
				Excess	$0.04715	$0.04761		
		< 1000 kW:	$0.30					
		> 1000 kW:	$0.15					
Proposed - Secondary	$215.90	Cust+Fac+Demand		All Energy	$0.03191	$0.03268	$11.38	$6.25
		< 1000 kW:	$0.76					
		> 1000 kW:	$0.56					
Marginal Costs	$215.95	< 1000 kW:	$0.76		$0.02611	$0.02674	$25.28	$10.41
		> 1000 kW:	$0.56					
PRIMARY 602					Summer	Winter	Summer	Winter
Current Rate	$40.00	Cust+Fac+Demand	$0.11	First 700,000	$0.05095	$0.05141	$7.24	$5.57
				Excess	$0.04695	$0.04737		
Proposed - Primary	$282.00	Cust+Fac+Demand	$0.48	All Energy	$0.03339	$0.03399	$10.93	$5.94
Marginal Costs	$282.08		$0.48		$0.02527	$0.02572	$24.29	$9.91
TRANSMISSION 632					Summer	Winter	Summer	Winter
Current Rate	$40.00	Cust+Fac+Demand	$0.00	First 700,000	$0.04974	$0.04996	$5.88	$4.73
				Excess	$0.04574	$0.04592		
Proposed - Transmission	$282.00	Cust+Fac+Demand	$0.00	All Energy	$0.02920	$0.02945	$8.26	$5.78
Marginal Costs	$282.08		$0.00		$0.02389	$0.02410	$16.53	$8.26

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

A. The figure below shows the annual average monthly bill impacts to the LGS Rate customers. The bill impacts for this class are in the range of 7 percent to 31 percent. About 75 percent of the customers on this rate will see an increase of about $400 or less per month.

Figure 9



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

A. OTP's proposal for the Large General Service Time of Day (LGS TOD) rate is to generally continue with the current design and adjust rate levels, as shown below.

We are also proposing to modify the time of day pricing periods under the LGS TOD rate. This time of day pricing period modification was examined in the 2018 Marginal Cost Study.[6] That analysis showed that the current time of day pricing periods should be updated to better reflect marginal costs. The current and proposed time of day pricing periods are shown in Exhibit___(DGP-1), Schedule 7.

The table below shows the current and proposed LGS TOD rates.

[6] *See* Section II of the 2018 Marginal Cost Study.

Table 13

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						Demand Charge per kW					
					Summer			Winter			Summer			Winter		
SECONDARY					PK 611	SH 615	OP 613	PK 611	SH 615	OP 613	PK 611	SH 615	OP 613	PK 611	SH 615	OP 613
Current Rate	$60.00	Cust. + Facilities	$0.30	< 1,000 kW	$0.08150	$0.06247	$0.03721	$0.07314	$0.05949	$0.04199	$5.75	$1.59	$0.00	$4.42	$1.22	$0.00
			$0.15	>=1,000 kW												
Rate 1	$215.90	Cust. + Facilities	$0.76	< 1,000 kW	$0.05596	$0.04257	$0.02818	$0.04903	$0.04368	$0.03054	$7.86	$3.44	$0.00	$3.49	$2.49	$0.00
			$0.57	>=1,000 kW												
Marginal Costs	$215.95		$0.76		$0.03832	$0.02891	$0.01980	$0.03445	$0.03009	$0.02148	$21.84	$3.34	$0.10	$5.29	$4.79	$0.33
			$0.57													
PRIMARY					PK 610	SH 614	OP 612	PK 610	SH 614	OP 612	PK 610	SH 614	OP 612	PK 610	SH 614	OP 612
Current Rate	$60.00	Cust. + Facilities	$0.11		$0.08115	$0.06221	$0.03709	$0.07278	$0.05921	$0.04181	$5.71	$1.57	$0.00	$4.39	$1.21	$0.00
Rate 1	$282.00	Cust. + Facilities	$0.48		$0.04529	$0.03457	$0.02300	$0.03945	$0.03527	$0.02475	$7.56	$3.36	$0.00	$5.42	$2.53	$0.00
Marginal Costs	$282.08		$0.57		$0.03787	$0.02891	$0.01923	$0.03299	$0.02949	$0.02070	$20.99	$3.28	$0.09	$5.03	$4.57	$0.31
TRANSMISSION					PK 639	SH 637	OP 640	PK 639	SH 637	OP 640	PK 639	SH 637	OP 640	PK 639	SH 637	OP 640
Current Rate	$60.00	Cust. + Facilities	$0.00		$0.07900	$0.06066	$0.03635	$0.07063	$0.05752	$0.04070	$4.86	$1.06	$0.00	$3.74	$0.82	$0.00
Rate 1	$282.00	Cust. + Facilities	$0.00		$0.03853	$0.02956	$0.02798	$0.03328	$0.02991	$0.02980	$5.52	$2.74	$0.00	$3.17	$2.48	$0.00
Marginal Costs	$282.08		$0.00		$0.03556	$0.02728	$0.01829	$0.0307	$0.0276	$0.0195	$13.79	$2.62	$0.12	$3.97	$4.02	$0.27

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

A. No. There is only one customer currently on this rate. Bill impacts will depend on customer usage patterns (season, level, and frequency of use in the three different periods (on, shoulder, and off-peak)). Therefore, there is a wide range of impacts that could be further influenced by how a customer responds to these new prices. Finally, individualized bill analysis could compromise the confidentiality of the customer.

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

A. OTP proposes to continue with the current design, but does propose to adjust rate levels. The proposed Standby Service rate, as shown in the table below, 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 14
Comparison of Current and Proposed Standby Service
Rate and Marginal Costs

North Dakota Standby Service

	Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh Summer PK	Summer SH	Summer OP	Winter PK	Winter SH	Winter OP	Demand Charge per kW Summer PK	Summer SH	Summer OP	Winter PK	Winter SH	Winter OP
SECONDARY															
Current Rate	$199.00	Cust. + Facilities	$0.07226	0.07319	0.05397	0.02437	0.06507	0.04917	0.03665	$0.7138	$0.00	$0.00	$0.7373	$0.00	$0.00
		Reserve Charge per kW		$0.1677			$0.0537			$0.7138			$0.7373	$ per kW per day	
Proposed	$242.24	Cust+Reservation+Facilities	$0.55	$0.05596	$0.04257	$0.02818	$0.04903	$0.04368	$0.03054	$0.5479	$0.00	$0.00	$0.4301	$0.00	$0.00
		Reserve Charge per kW		$0.6564			$0.2235			$0.5479			$0.4301	$ per kW per day	
Marginal Costs	**$215.95**		**$0.75**	**$0.03932**	**$0.02991**	**$0.01980**	**$0.03445**	**$0.03069**	**$0.02146**	**$21.84**	**$3.34**	**$0.10**	**$5.29**	**$4.79**	**$0.33**
PRIMARY															
Current Rate	$199.00	Cust. + Facilities	$0.05283	0.07067	0.05228	0.02376	0.06251	0.04742	0.03546	$0.6838	$0.00	$0.00	$0.7003	$0.00	$0.00
		Reserve Charge per kW		$0.1604			$0.0510			$0.6838			$0.7003	$ per kW per day	
Proposed	$304.33	Cust+Reservation+Facilities	$0.45	$0.04529	$0.03457	$0.02300	$0.03945	$0.03527	$0.02475	$0.6838	$0.00	$0.00	$0.7003	$0.00	$0.00
		Reserve Charge per kW		$0.6284			$0.2140			$0.5246			$0.4080	$ per kW per day	
Marginal Costs	**$304.33**		**$0.48**	**$0.04693**	**$0.0358**	**$0.02028**	**$0.03884**	**$0.03582**	**$0.02402**	**$0.52**	**$0.00**	**$0.00**	**$0.41**	**$0.00**	**$0.00**
TRANSMISSION															
Current Rate	$199.00	Cust. + Facilities	$0.00	$0.06660	$0.04952	$0.02272	$0.05844	$0.04460	$0.03352	$0.6367	$0.00	$0.00	$0.6433	$0.00	$0.00
		Reserve Charge per kW		$0.1490			$0.0468			$0.6367			$0.6433	$ per kW per day	
Proposed	$304.33	Cust+Reservation+Facilities	$0.00	$0.03853	$0.02956	$0.02798	$0.03328	$0.02991	$0.02980	$0.4881	$0.00	$0.00	$0.3742	$0.00	$0.00
		Reserve Charge per kW		$0.5842			$0.1990			$0.4881			$0.3742	$ per kW per day	
Marginal Costs	**$304.33**		**N/A**	**$0.0440**	**$0.03376**	**$0.01926**	**$0.0360**	**$0.0333**	**$0.0225**	**$0.49**	**$0.00**	**$0.00**	**$0.37**	**$0.00**	**$0.00**

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

A. OTP has only one customer currently taking Standby Service, therefore there are no bill impacts available for the same reasons as mentioned above for the TOU rate.

E. Irrigation Class

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

A. There is only one rate schedule in the Irrigation Class, the Irrigation Service rate (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. OTP's proposed rate, shown the table below, maintains the current two service options, both of which provide service from April 15 through November 1. The proposal for both Option 1 and Option 2 retain the customer-specific facilities charges included in the current rate.

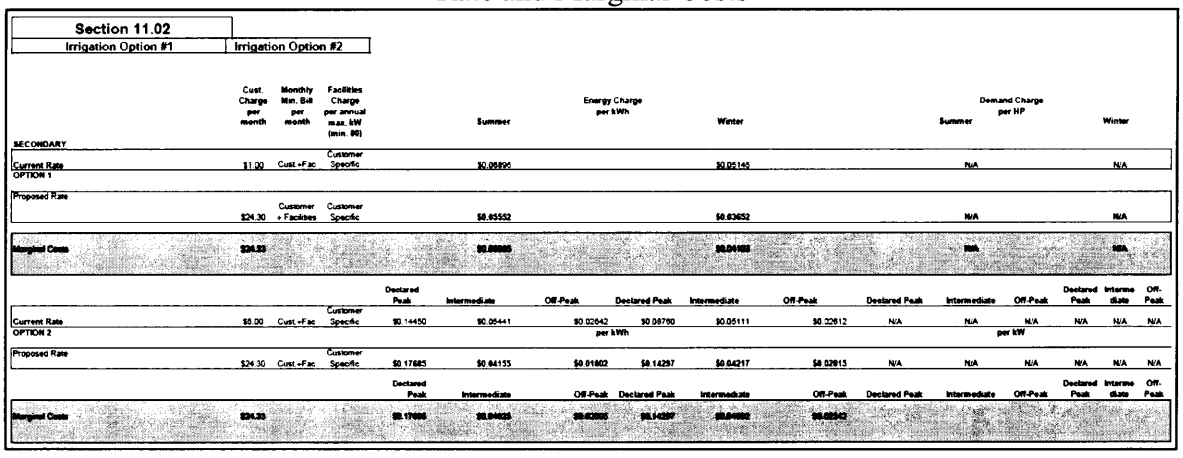
The Option 1 (Non-Time-Of-Use) rate continues with seasonal energy charges. The Option 2 (Time-of-Use) rate consists of energy charges for off-peak, intermediate, and on-peak or "declared" periods. The declared hours are defined by OTP when the system is experiencing peak conditions. Like the General Service Time of Use rate, the declared peak hours are proposed to move from approximately 200 hours per year to approximately 100 hours per year. The proposal for Irrigation Option 2 is to set the price for hours when OTP is experiencing peak conditions at 100 percent of marginal cost (energy plus capacity), thereby giving Option 2 irrigation customers a transparent signal to curtail use during peak periods. These "on peak" or "declared-peak" marginal costs are the average marginal costs expected in the hours defined to be declared peak by OTP, and they vary by season. In the intermediate hours (which include the remainder of peak period hours and shoulder hours), energy and demand charges will apply. In the off-peak hours, only energy charges apply. The customer charge is set at 99.9 percent of marginal costs.

We are also proposing a slight modification to the classification of peak and off-peak hours under this rate by extending the time of day concept to Sundays. And the proposed tariff sheets provide clarifications for the process of notifying customers of declared peak periods.

Table 15

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																	
		Cust. Charge per month	Monthly Min. Bill per month	Facilities Charge per annual max. kW (min. 80)	Energy Charge per kWh						Demand Charge per HP							
					Summer				Winter					Summer			Winter	
SECONDARY																		
Current Rate OPTION 1		$11.00	Cust.+Fac.	Customer Specific	$0.05895				$0.05145					N/A			N/A	
Proposed Rate		$24.30	Customer + Facilities	Customer Specific	$0.05552				$0.03652					N/A			N/A	
Marginal Costs		$24.33			[illegible]				[illegible]					N/A			N/A	
					Declared Peak	Intermediate	Off-Peak	Declared Peak	Intermediate	Off-Peak	Declared Peak	Intermediate	Off-Peak	Declared Peak	Intermediate	Off-Peak		
Current Rate OPTION 2		$8.00	Cust.+Fac.	Customer Specific	$0.14450	$0.05441	$0.02642 per kWh	$0.08780	$0.05111	$0.02612	N/A	N/A	N/A per kW	N/A	N/A	N/A		
Proposed Rate		$24.30	Cust.+Fac.	Customer Specific	$0.17685	$0.04153	$0.01802	$0.14297	$0.04217	$0.02615	N/A	N/A	N/A	N/A	N/A	N/A		
					Declared Peak	Intermediate	Off-Peak	Declared Peak	Intermediate	Off-Peak	Declared Peak	Intermediate	Off-Peak	Declared Peak	Intermediate	Off-Peak		
Marginal Costs		$24.33			[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]								

F. Outdoor Lighting Class

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

A. There are two rates in the Outdoor Lighting Class: Outdoor Lighting – Energy Only (Section 11.03) and Outdoor Lighting (Section 11.04). OTP is proposing to close the Outdoor Lighting (Section 11.04) to new customers and replacements. This proposal is discussed further in Section V.D, below.

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 11.03 OUTDOOR LIGHTING-ENERGY ONLY RATE (RATE CODES 748 AND 749 AND 744).

A. OTP's proposal is shown in the table below. Customer charge will be unchanged and would remain at $2.00 per month. Energy charges were increased to meet the class revenue requirement.

Table 16
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	0.06978
Proposed Rate	$2.00	$2.00	$0.00	0.07047
Marginal Costs	**$10.36**		**$0.00**	**$0.02945**
Non-Metered				
Current Rate	Connected kW x	$23.84	Current rate * 4100 hrs in year / 12 months	
Proposed Rate	Connected kW x	$24.08	Current rate * 4100 hrs in year / 12 months	

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

A. The overall bill impacts for the rate are 25.67 percent.

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

A. The bill impacts for each current lighting fixture are the same, 11.02 percent.

G. Other Public Authority Service Class

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING 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. As shown in the table below, the customer charge is set at approximately 100 percent of marginal costs. OTP is eliminating the fixed facilities charge per month and proposing a $/kW facilities charge per month. The new facilities charges are set at marginal costs.

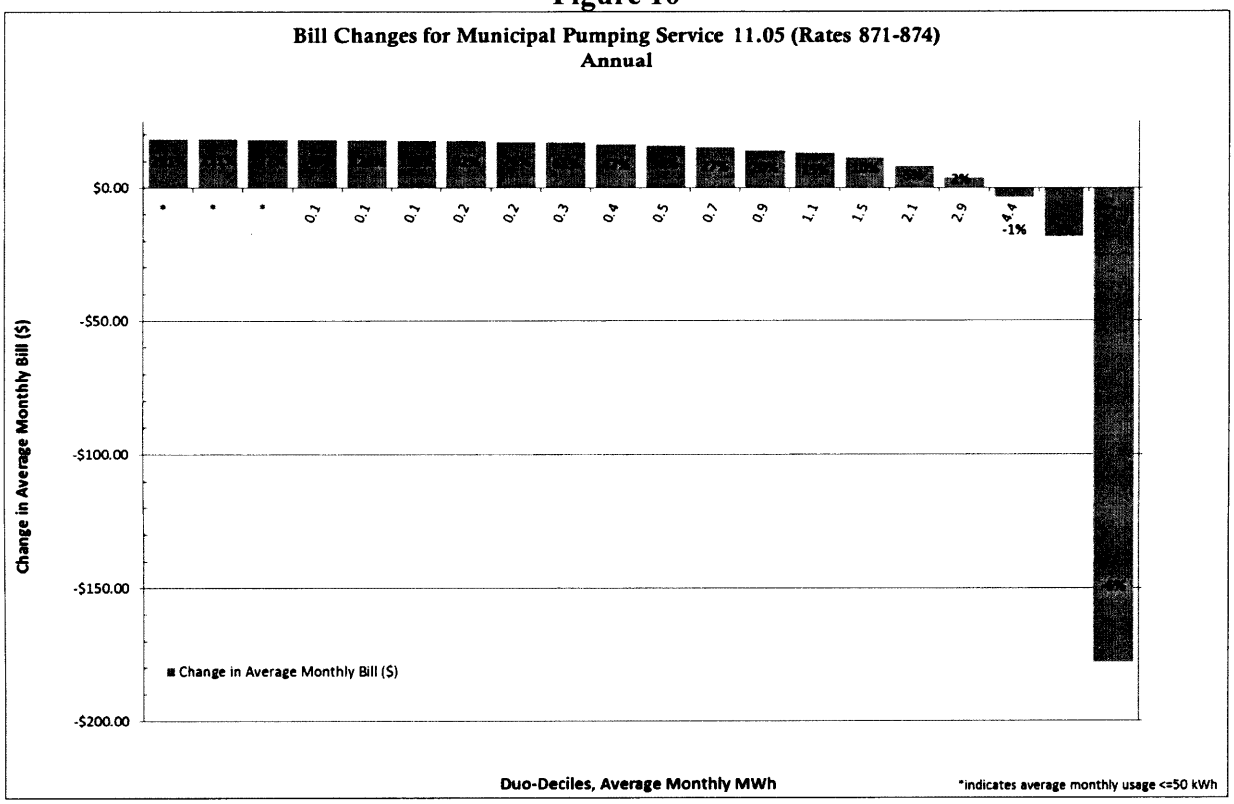
Table 17
Current and Recommended 11.05 Municipal Pumping
Rates and Marginal Costs

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	$4.00	Cust + Fac	per month	$4.00	$0.06523	$0.05950
	Primary	$4.00	Cust + Fac	per month	$2.68	$0.06494	$0.05922
Proposed Rate	Secondary	$26.50	Cust + Fac	per KW	$0.65	$0.05159	$0.03490
	Primary	$26.50	Cust + Fac	per KW	$0.65	$0.04972	$0.03344
Marginal Costs		$26.55		Secondary Primary	$0.98 $0.65		
All Season				Secondary Primary	Energy & Demand $0.06065 $0.05845	$0.04103 $0.03931	

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

A. The figure below reflects varied bill impacts, estimated based on similar usage and demand characteristics, as the consumption levels of customers vary significantly under this rate. Most of the customers have bill impacts of less than $20.00 per month.

Figure 10



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

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

Table 18

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	$0.42962
Marginal Costs	**$26.55**			**$0.03569**

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

A. The bill impacts are presented in a simple monthly bill comparison in the figure below. The proposed increase for this rate is 16 percent. The greatest annual dollar impact is $0.12.

Figure 11
Monthly Bill Impacts - 11.06 Civil Defense-Fire Siren Service

Siren HP	Monthly Impacts			
	Current Bill	Proposed Bill	Difference	% Change
1	$ 1.53	$ 1.65	$ 0.12	8%
1.5	$ 1.80	$ 1.86	$ 0.07	4%
2	$ 2.06	$ 2.08	$ 0.02	1%
2.5	$ 2.33	$ 2.29	$ (0.04)	-2%
3	$ 2.60	$ 2.51	$ (0.09)	-3%
3.5	$ 2.86	$ 2.72	$ (0.14)	-5%
4.5	$ 3.39	$ 3.15	$ (0.24)	-7%
5	$ 3.66	$ 3.37	$ (0.29)	-8%
6.5	$ 4.46	$ 4.01	$ (0.45)	-10%
7	$ 4.72	$ 4.23	$ (0.50)	-11%
7.5	$ 4.99	$ 4.44	$ (0.55)	-11%
10	$ 6.32	$ 5.52	$ (0.80)	-13%
12.5	$ 7.65	$ 6.59	$ (1.06)	-14%
20	$ 11.64	$ 9.81	$ (1.83)	-16%

H. Water Heating Service Class

Q. WHAT RATE SCHEDULES ARE YOU INCLUDING IN THE WATER HEATING SERVICE CLASS?

A. There is only one rate in the Water Heating Class, the Water Heating – Controlled Service Rider (Section 14.01).

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

A. The proposal for the Metered Water Heating Control Service (Rate Code 30-91) shown in the table below increases the customer charge to approximately 71 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 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	Winter
Current	Customer Charge, Seasonal Energy	$1.00	Cust. + Facilities	$1.00	$0.05773	$0.05638
Proposed Rate	Customer Charge, Seasonal Energy	$4.00	Cust. + Facilities	$2.00	$0.03317	$0.02868
Marginal Costs		**$5.59**		**$5.85**	**$0.03990**	**$0.03450**

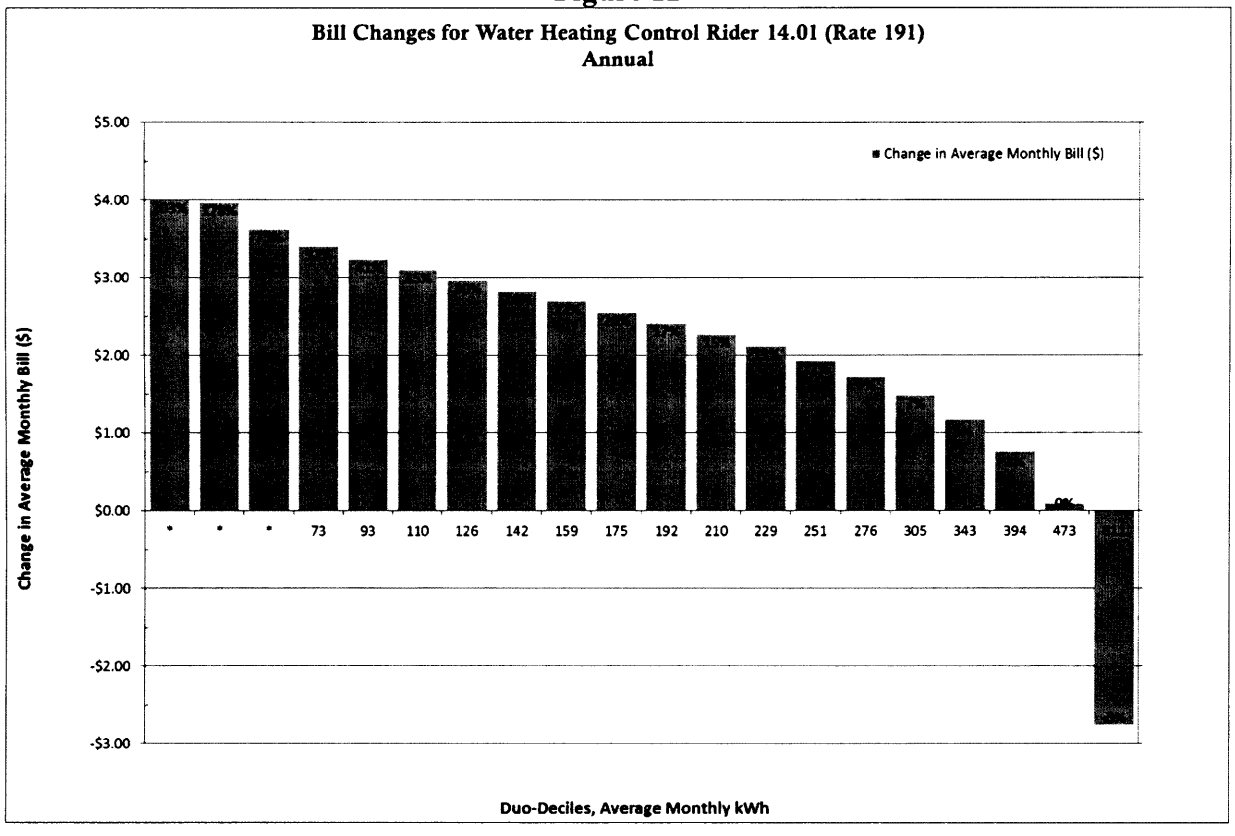
The Water Heating Control Service Credit (Rate Code 192) is essentially a direct load-control program similar to direct load-control of central air conditioners. Under the rate, in exchange for allowing OTP to interrupt the water heating service during high-cost periods, OTP compensates the customer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

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

A. Under OTP's proposal, shown in the figure below, no Metered Water Heating Control Service (Rate Code 30-91) customer sees a monthly increase of more than $4.00. The bill 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, Section IV.A, above).

Figure 12



I. Controlled Service – Interruptible Class

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

A. There are three current rates in the Interruptible Service Class: Controlled Service – Interruptible Load (CT Metering, Section 14.04) Rider; Controlled Service – Interruptible Load (Self-contained metering, Section 14.05); and Controlled Service – Interruptible Load (CT Metering – Option 2, Section 14.04).

Q. PLEASE DESCRIBE YOUR RATE DESIGN PROPOSAL FOR THE 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 customer and facilities charge are set at 100 percent of marginal costs. The energy rate is at about 30 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 20
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	$4.00	Cust. + Facilities	$0.08 per kW	All kWh	$0.03166	$0.03044
				Penalty kWh	$0.39448	$0.12726
Proposed Rate	$20.20	Cust. + Facilities	$0.76 per kW	All kWh	$0.01060	$0.01005
				Penalty kWh	$0.41350	$0.14322
Marginal Costs	**$20.27**	**<300 kW**	**$0.76**	**All kWh**	**$0.03497**	**$0.03315**
		>=300 kW	**$0.76**	**Penalty kWh**	**$0.41350**	**$0.14322**

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

A. As shown in the table below, the customer and facilities charges are set at almost 100 percent of marginal costs while the energy rate is at about 30 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 21
Current and Proposed
Option 2 Controlled Service-Interruptible Load (CT Metering) Rider Section 14.04
Rate and Marginal Costs

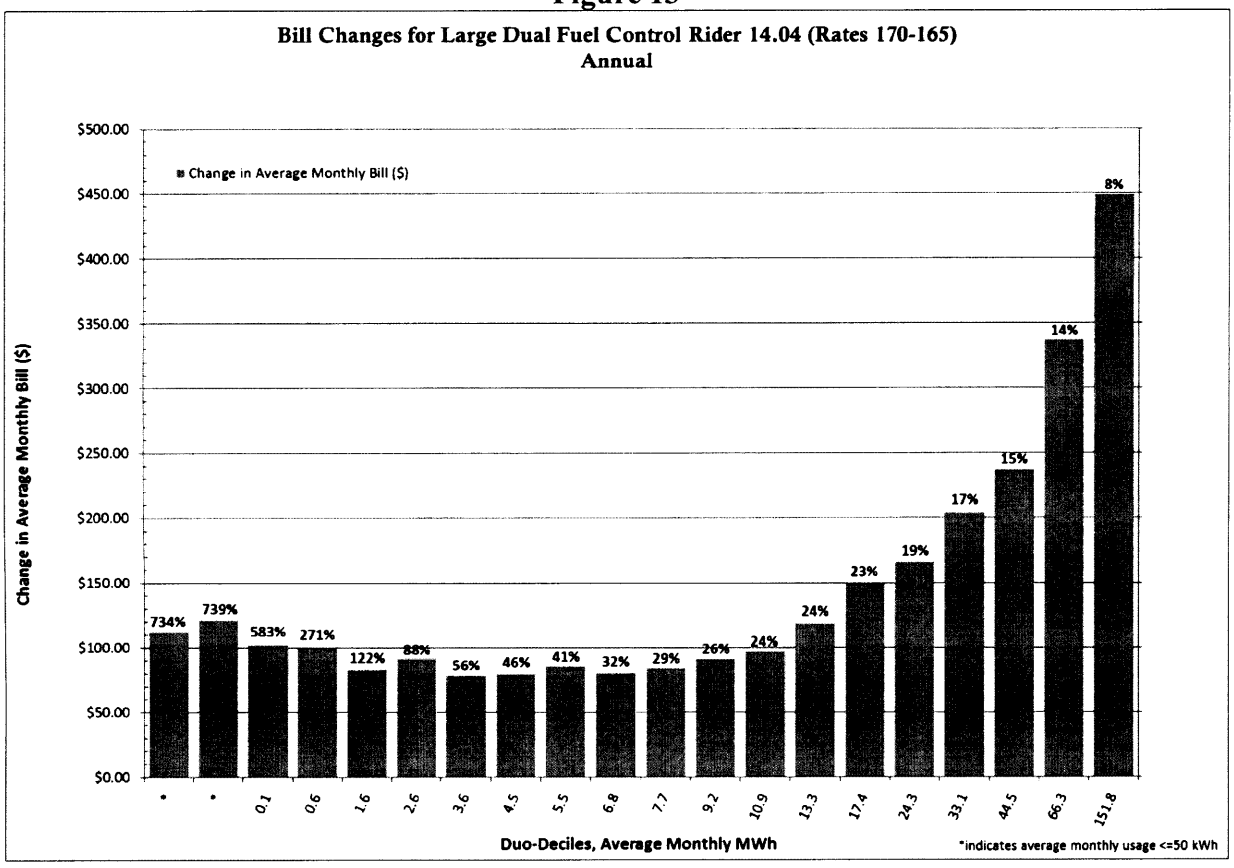
Large Dual Fuel - Option 2	Section 14.04						
Controlled Service-Interruptible (assumes all customers have CT metering)							
	Customer Charge per month	Monthly Minimum Bill per month	Facilities Charge	Energy Charge per kWh Summer	Energy Charge per kWh Winter	Demand Charge per kW Summer	Demand Charge per kW Winter
CURRENT RATE OPTION 2							
Secondary Seasonal Energy, kW Facilities All kWh	$5.00	Customer + Facilities charge	per annual max. kW per month ($ per Month)	$0.03336	$0.03208	$7.29	$5.61
		per kW	$0.08				
SECONDARY							
Proposed Rate	$20.20	Customer + Facilities charge	per annual max. kW per month	$0.01060	$0.01005	$11.38	$6.25
		per kW	$0.76				
Marginal Costs	**$20.27**	**<300 kW**	**$0.76**	**$0.03496**	**$0.03315**	**$ 25.28**	**$ 10.41**
		>=300 kW	**$0.50**	**(Plus 5% firm energy charge)**			

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED 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 $100 and the rest of the customers with increases from 8 to 23 percent.

The proposed rate for Option 2 shows a rate class increase of 9.5 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 14.05 CONTROLLED SERVICE-INTERRUPTIBLE LOAD (SELF-CONTAINED METERING) RIDER.

A. OTP's proposal for this rate, as shown in the table below, increases 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 22

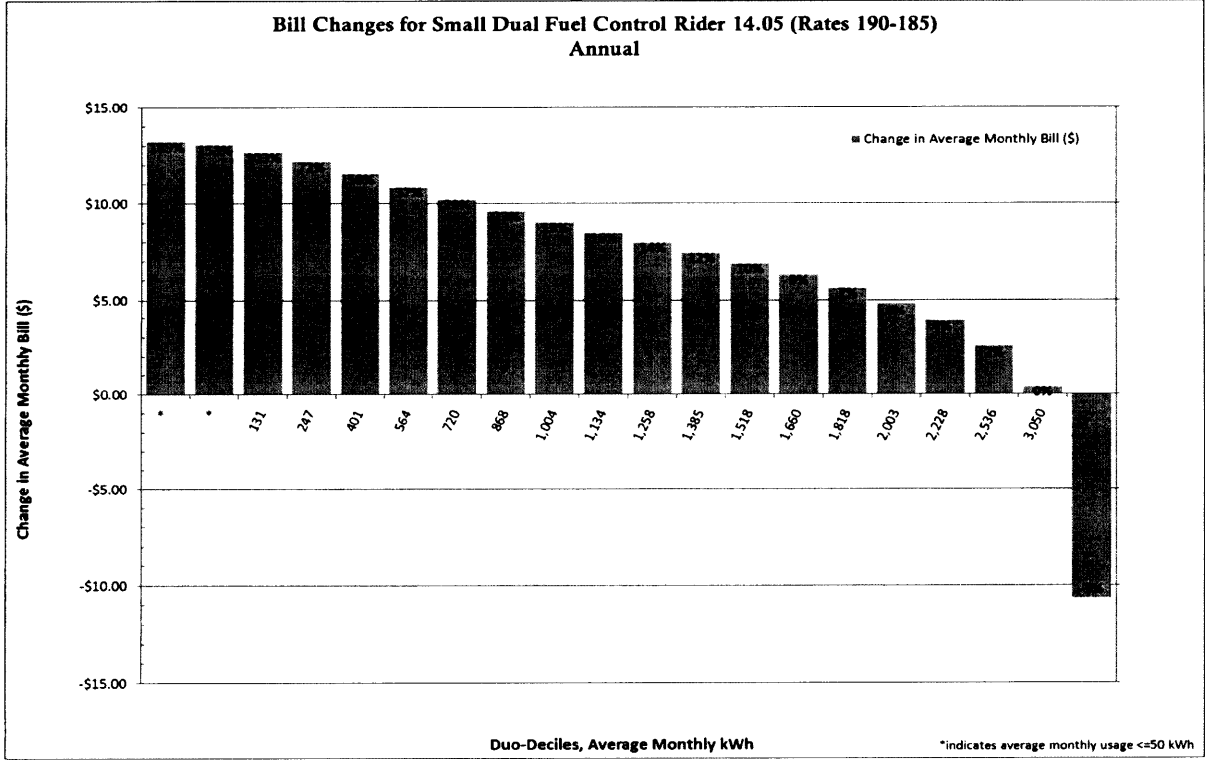
Current and Proposed 14.05 Controlled Service-Interruptible Load (Self-Contained) Rider Rate and Marginal Costs

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	$2.00	Cust. + Facilities Charge	Fixed Facilities	$5.00	All kWhs	$0.03659	$0.03451
					Penalty kWhs	$0.38606	$0.12924
Proposed Rate	$8.50	Cust. + Facilities Charge	Fixed Facilities	$11.70	All kWhs	$0.01111	$0.01037
					Penalty kWhs	$0.41350	$0.16537
Marginal Costs	$20.27		<5000 kWh in all months	$11.69	All kWhs	$0.03792	$0.03539
			> 5000 kWh in any month	$46.11	Penalty kWhs	$0.41350	$0.16537

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

A. The figure below shows about 90 percent of the class customers have annual average bill impacts under $14.00 per month. The remaining 10 percent of customers will see some savings.

Figure 14



J. Deferred Load Service Class

Q. WHAT RATE SCHEDULES ARE YOU PROPOSING TO INCLUDE IN THE DEFERRED LOAD SERVICE CLASS?

A. There are two rates in the Deferred Load Service Class: Controlled Service – Deferred Load Rider (Section 14.06) and Fixed Time of Service Rider (Section 14.07).

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

A. The proposed Deferred Load Service Rider, as shown in the table below, moves the customer charge to approximately 100 percent of marginal costs and increases the facilities charge from $4.00 per month to $11.60 per month, at 99.9 percent of marginal cost. Seasonally differentiated energy charges in the proposed design were adjusted to account for the change in the customer and facilities charges.

The penalty for energy used during a control period is intended to deter customers from unauthorized use during control periods.

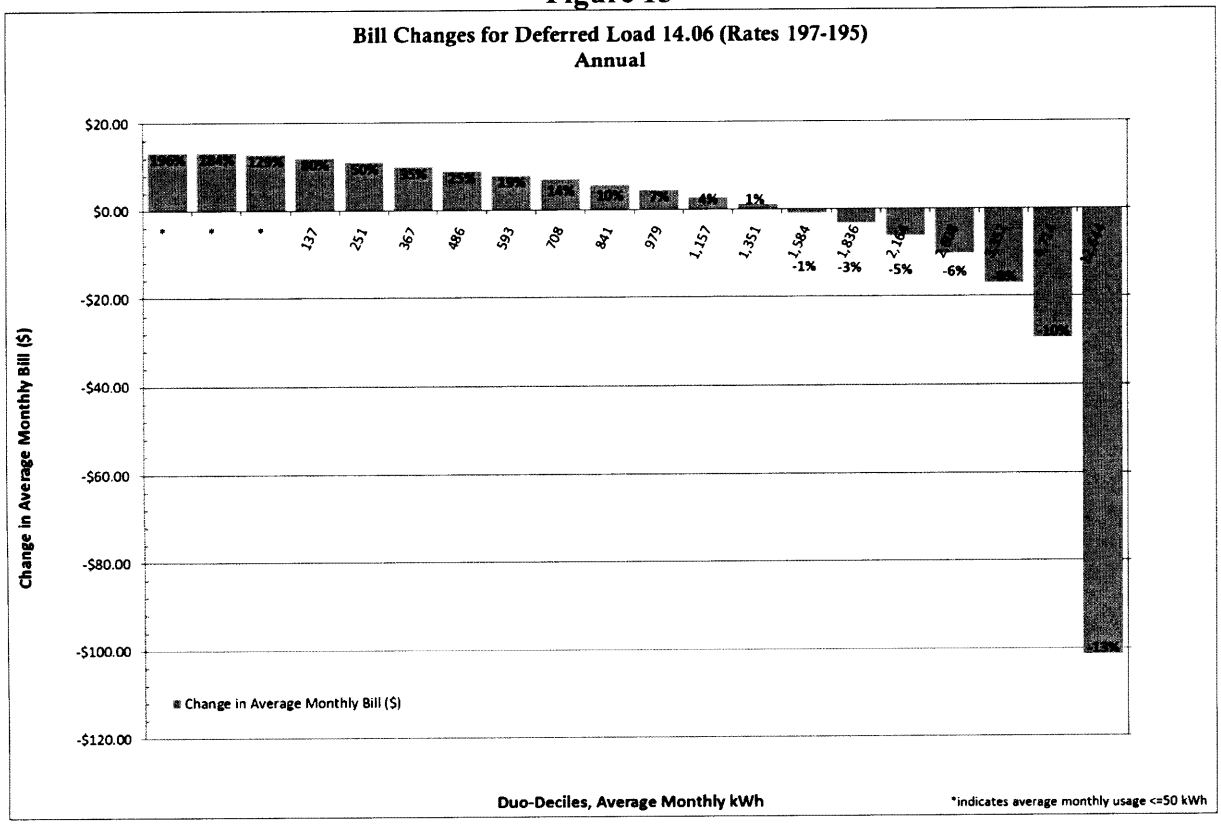
Table 23
Current and Proposed 14.06 Deferred Load Rider Rates and Marginal Costs.

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	$3.00	Customer Charge+Facilities	Flat charge per month	$4.00	All kWhs	$0.05154	$0.05002
					Penalty kwhs	$0.33802	$0.11510
Proposed Rate	$8.80	Customer Charge+Facilities	Flat charge per month	$11.60	All kWhs	$0.02762	$0.02516
					Penalty kwhs	$0.35916	$0.16537
Marginal Costs	$8.86		Urban	$11.69		$0.03885	$0.03539
			Rural	$46.11		$0.35916	$0.16537

Q. WHAT ARE THE BILL IMPACTS OF PROPOSED 14.06 DEFERRED LOAD RIDER?

A. As the figure below shows, 90 percent of the customers on this rider, will see bill increases of less than $10.00 per month. Forty percent of the customers will see savings up to 13 percent.

Figure 15



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

A. The proposed Fixed Time of Service (f/k/a Fixed Time of Delivery) rider introduces increases to customer charges for secondary service and increases to facilities charges for all voltages to bring both customer and facilities 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.

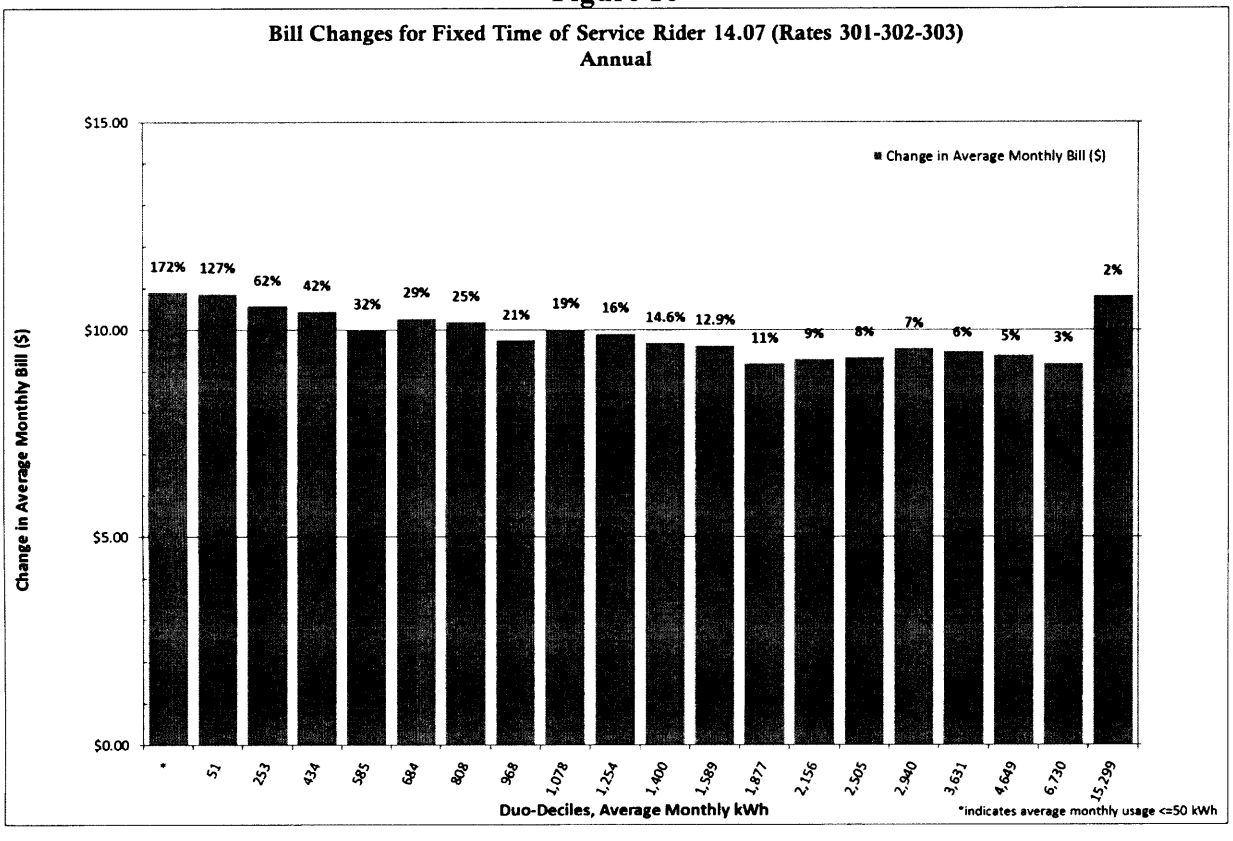
Table 24
Current and Recommended 14.07 Fixed Time of Service Rider
Rate and Marginal Costs

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)	$1.00		$3.00		$0.01626	$0.03325
				Penalty kWh	$0.05676	$0.03605
Secondary CT Metering (302)	$1.50		$19.00		$0.01626	$0.03325
				Penalty kWh	$0.05676	$0.03605
Primary (303)	$3.00		$9.00		$0.01620	$0.03312
				Penalty kWh	$0.05670	$0.03592
Proposed Rate		Customer + Facilities Charge			**Summer**	**Winter**
Secondary Self-Contained Metering (301)	$6.70		$6.00		$0.01525	$0.01687
				Penalty kWh	$0.06736	$0.04602
Secondary CT Metering (302)	$6.70		$38.00		$0.01525	$0.01687
				Penalty kWh	$0.06736	$0.04602
Primary (303)	$6.70		$18.00		$0.01519	$0.01680
				Penalty kWh	$0.06736	$0.04602
Marginal Costs			**$ per a month**			
Secondary Self-Contained Metering (301)	**$6.71**		**$9.77**		**$0.01553**	**$0.01718**
				Penalty kWh	**$0.06736**	**$0.04602**
Secondary CT Metering (302)	**$6.71**		**$75.60**		**$0.01553**	**$0.01718**
				Penalty kWh	**$0.06736**	**$0.04602**
Primary (303)	**$6.71**		**$57.30**		**$0.01547**	**$0.01711**
				Penalty kWh	**$0.08255**	**$0.06282**

Q. WHAT ARE THE BILL IMPACTS OF THE PROPOSED 14.07 FIXED TIME OF SERVICE RIDER?

A. The figure below shows varied bill impacts for all customers on the proposed Fixed Time of Service Rider, most of the customers will see a bill increase around or less than $10.

Figure 16



K. Mandatory and Voluntary Riders

Q. ARE THERE ANY OTHER CHANGES TO OTP'S MANDATORY AND VOLUNTARY RIDERS?

A. Yes. Mr. Tommerdahl and Ms. Ice discuss certain proposed changes to OTP's Mandatory Riders contained in Section 13.0 of the rate schedule.

V. NEW RATE PROPOSALS

Q. IS OTP MAKING ANY NEW RATE PROPOSALS IN THIS CASE?

A. Yes. We are requesting the addition of three rate schedules to allow us to better meet customers' needs. We are also proposing a new rider to facilitate the recovery of future investments, modifying our Lighting service and expanding our Air Conditioning rider to business customers. These proposals are discussed in more detail below.

A. Residential Time of Day

Q. PLEASE PROVIDE A SUMMARY OF THE RESIDENTIAL TIME OF DAY-PILOT.

A. The Residential Time-of-Day Pilot (Pilot) proposal is aligned with our rate structure objectives to offer rates with seasonal and time of day differences. It is being offered to certain Residential customers, limited to 50 single-metered customers served on the Residential Service (Section 9.01). The Pilot utilizes three time-of-day periods (on-peak, shoulder, and off-peak) for each season (summer and winter). These time of day periods are designed based on forecasts of the MISO energy market and reflect the marginal cost of service. The Pilot will be under proposed Rate Schedule 9.04, a copy of which is included in Volume 2D.

Q, WHAT ARE THE OBJECTIVES OF THE RESIDENTIAL TIME OF DAY-PILOT?

A. OTP has identified three objectives:

1. Learn from and respond to customers;
2. Assess system costs and revenues; and
3. Inform future Automated Metering Infrastructure (AMI) investments.

Q. PLEASE FURTHER EXPLAIN THE PILOT OBJECTIVES.

A. The over-arching theme of the Pilot is to learn from our customers and the impacts they can make in relation to system costs and infrastructure investments.

1. **Learn from and Respond to Customers**: The Pilot introduces more granular pricing that can help customers to better affect their bills through behavioral changes. Some of those behavioral changes could come in the form of automation (*e.g.* programable timers and wi-fi enabled thermostats for electric vehicles/conditioned spaces), while others may relate to shifting usage to certain times of the date in response to the prices charged. Once customers become acclimated and comfortable with the Pilot, we expect to learn from customers what strategies they used to change their usage behavior. We also expect some customers may not acclimate to the designed time periods – which is also useful information. Finally, we intend to assess the extent customers are able to realize

bill savings without changing behavior in order to further refine future rate designs.

2. **Assess System Costs and Revenues**: If customers react to the Pilot price signals by shifting usage during high-price periods to lower priced-periods, OTP may experience a lower cost of service. Time-shifting can also impact revenue collections. Understanding these tradeoffs is important before expanding a time-of-day rate structure to the entire Residential class.

3. **Inform Future AMI Investment**: Facilitating additional rate options is a key functionality of AMI. Lessons learned from the Pilot will help us better understand the true value of that functionality. We also anticipate the Pilot will help OTP assess what equipment and features are useful and provide lessons that can be applied to a potential future AMI roll-out.

Q. HOW WAS THE PILOT DESIGNED?

A. The Pilot is built from the 2018 Marginal Cost Study time-of-day periods and associated marginal costs. We compiled representative billing determinants for each pricing period (*e.g.* summer on-peak/shoulder/off-peak; winter on-peak/shoulder/off-peak) from OTP's 2016 hourly Residential load research data for customers that would be eligible for the Pilot. Then, we used the 2018 Marginal Cost Study time-of-day periods and associated marginal costs and the billing determinants to establish revenue neutral rates.

Q. WHAT DO YOU MEAN BY THE TERM "REVENUE NEUTRAL"?

A. When more than one rate is designed for a specific rate class, and the same customers can choose between one or more rates in the rate class, rates are designed to recover the same amount of revenue for that specific rate class no matter which rate the customer chooses. It is important to design rates to be revenue neutral to maintain revenue adequacy and stability.

Q. DOES A REVENUE NEUTRAL DESIGN MEAN CUSTOMERS WILL NOT SAVE MONEY IN THE PILOT?

A. No. The Pilot is designed based on historical usage data, meaning it reflects customers' behavior without the Pilot price signals being in place. Customers that are able to change their behaviors in response to the Pilot price signals may save money. Some customers participating in the Pilot may also save money without changing behavior simply because their existing usage is aligned with the pricing period.

Q. ARE THESE OUTCOMES EQUALLY DESIRABLE?

A. No. Customers that change their usage in response to the Pilot pricing help lower costs, which will ultimately benefit all customers and OTP. Capturing these kind of behavioral and cost changes is one of the main goals of time-of-day pricing. One of the goals of the Pilot is to better understand customers' usage (including their ability to change usage in response to more granular price signals) so that the rate design can be further refined to make sure that customer savings are aligned with reductions in the cost of providing service.

Q. WHAT CUSTOMERS ARE ELIGIBLE FOR THE PILOT?

A. There are currently about 30,500 Residential customers that are eligible for the Pilot. Pilot eligibility is limited to single-metered customers taking Residential Service (Section 9.01). This means that customers taking Residential – Controlled Demand (Section 9.02) service or utilizing our Water Heating – Controlled Service Rider (Section 14.01), other Controlled Service Riders (Sections 14.04-14.05), Controlled Service – Deferred Load Rider (Section 14.06) and Fixed Time of Service Rider (Section 14.07) are not eligible for the Pilot. We have not included these customers in the Pilot to simplify and focus on usage delivered under a single meter. This allows customers to face a single price signal and funnels all electricity usage through a single point of measurement. I do note that most of OTP's Voluntary Riders are interruptible services.

Q. HOW WILL CUSTOMERS ENTER INTO THE PILOT?

A. Customers will opt-in to the Pilot on a voluntary basis. OTP will, however, encourage eligible customers that already participate in OTP's load research program to enter into the Pilot. As participants in OTP's load research program, these customers already have metering that is compatible with the Pilot. Data from these customers is also especially valuable because OTP already has historical time-based usage data from these customers that can serve as a baseline for measuring the impact of the Pilot. We also anticipate participation by customers outside of the load research group in order to achieve the desired sample size. To reach the desired sample size, we will utilize simple random sampling of the target population, described in the Pilot eligibility above. For those that agree to participate, based on availability, we will proceed to engage the customer with the Pilot welcome packet containing important information about the pilot and schedule a start date.

Q. WHY LIMIT THE PILOT TO ONLY 50 CUSTOMERS?

A. This level of customers will allow for both cost effectiveness and statistically meaningful results.

Q. WHAT IS YOUR STATISTICAL BASIS FOR 50 CUSTOMERS BEING A MEANINGFUL SAMPLE?

A. We are relying on the central limit theorem which essentially states the more sample points you collect, the more the sampling distribution of the sampling mean approaches a normal distribution (i.e., a bell curve). The theorem holds true for sample sizes over 30. We are including additional sample points for attrition purposes.

Q. WHAT IS THE PROPOSED LENGTH OF THE RESIDENTIAL TIME OF DAY PILOT?

A. If approved, OTP plans for the Pilot to remain open for two years, effective January 1, 2019. The additional time between the final Order and implementation is necessary to develop Pilot marketing materials, install metering, and establish other

program monitoring. We also believe that 2-4 months is an appropriate amount of time to sign customers up for the Pilot.

Q. WILL CUSTOMERS REMAIN IN THE PILOT FOR THE ENTIRE TWO YEARS?

A. It is OTP's expectation that most of the Pilot participants remain engaged in the Pilot for the full two years. One of the Residential Time of Day Pilot rules states:

> Preference for participation will be given to customers who agree to a minimum of 12 months participation. Customers may elect service under this schedule for a trial period of three months. If a customer chooses to return to other available rate schedules after the trial period, the customer will pay a charge of $20.00 for removal of time of day metering equipment.

Q. WILL OTP ENDEAVOR TO KEEP THE PILOT FULLY SUBSCRIBED?

A. Yes. We are aiming to have the Pilot fully subscribed pilot at the initial start date of January 1, 2019. If there is customer attrition, we will continue outreach in order to encourage participation.

Q. WILL OTP WORK WITH CUSTOMERS DURING THE PILOT?

A. Yes. We are seeking engaged customers that are willing to work smart on managing their energy usage and OTP will be available to assist customers along the way. Specifically, one of the Pilot rules is that:

> The Company will endeavor to work with participants to assist with various measures to improve energy efficiency and other cost saving measures.

B. Super LGS

Q. PLEASE PROVIDE A SUMMARY OF THE SUPER LARGE GENERAL SERVICE PROPOSAL.

A. The Super Large General Service (SLGS) proposal is primarily designed to attract high load factor large/commercial customers into OTP's service territory. Customers that meet the criteria will have access to individual contract pricing based on OTP's marginal cost of service. The proposal incorporates a regulatory pre-approval process and ratepayer protections that will ensure net benefits to all customers. OTP believes its proposal will provide prospective customers improved speed and price certainty, making it easier for

businesses to invest in North Dakota. Additional details regarding the SLGS proposal are available in Proposed Rate Schedule 10.06, a copy of which is included in Volume 2D.

Q. WHY INTRODUCE A NEW RATE WHEN OTP ALREADY HAS A LARGE GENERAL SERVICE RATE?

A. The customers OTP is targeting have much larger volume characteristics and higher load factors than the existing classes and rates, which leads to a relatively lower per-kWh average cost of service versus those on the existing rates. By making this proposal, OTP is positioning itself to offer competitive rates that will attract these types of customers to its service territory.

Q. WHAT IS THE ELIGIBILITY CRITERIA FOR THE SLGS RATE?

A. The SLGS rate will be available to new load (*i.e.* new customers or new facility opened by an existing customer) that has the following characteristics: (1) expected metered demand of at least 25 MW at a single metering point; (2) a load factor of at least 80 percent; and (3) and annual energy sales of at least 175,000 MWh's over 12 consecutive billing months.

Q. PLEASE DISCUSS WHAT YOU MEAN BY "INDIVIDUAL CONTRACT PRICING BASED ON OTP'S MARGINAL COST TO SERVE."

A. Unlike standard rate schedules where customers within the same rate class essentially pay the same rates for customer, facility, energy and demand charges, customers served under the SLGS rate would have customized rates based on their specific load characteristics and investment needed to serve them. SLGS customers also would pay marginal costs versus embedded costs.[7]

[7] As discussed above, marginal costs are costs on a prospective basis (expected or forecasted) versus embedded costs which are retrospective (historical).

Q. DESCRIBE A NEW CUSTOMER SITUATION AND THE ASSOCIATED MARGINAL COSTS OTP WOULD INCUR.

A. A new customer taking service under the SLGS rate will require OTP to incur marginal energy and capacity costs, and may also require upstream distribution system reinforcement (if the SGLG is a distribution customer), new local dedicated facilities, marginal transmission costs (FERC-approved transmission rate), as well as marginal customer costs (meter, service drop, and associated customer services). OTP would develop marginal costs associated with the customer addition from OTP's most recent Marginal Cost Study.

Q. IS THIS MARGINAL COST-BASED PRICING APPROACH SUPPORTED BY ECONOMIC THEORY?

A. Yes. The SLGS rate will be such that customers are paying at least their marginal cost of service. This means other customers are not harmed by the SLGS pricing. Further, to the extent that the marginal costs associated with the addition of a SLGS customer includes certain fixed costs, adding these customers to the system makes a valuable contribution to the cost of service.

Q. DOES OTP HAVE ANY OTHER SERVICE OFFERINGS THAT UTILIZE MARGINAL COST-BASED RATES?

A. Yes. OTP offers a few rates that are priced on a marginal (prospective) basis. In the Large General Service Class, there are two riders (the LGS Rider and the Real-Time Pricing (RTP) Rider) that utilize estimates of day-ahead pricing in the MISO market. Another group of rates of this type are known as the Small Power Production rates. For those rates, OTP estimates its avoided costs and uses those estimates to pay customers with distributed generation systems avoided cost rates for energy and/or capacity when delivered to the OTP system.

Q. PLEASE DISCUSS THE REGULATORY PRE-APPROVAL PROCESS IN THIS PROPOSAL.

A. The foundation of the regulatory pre-approval process is to utilize a marginal cost-to-serve model and provide the model to the Commission Staff for verification of rate offerings. The model houses OTP's expected marginal unit cost to serve and the customer's expected load requirements. The marginal unit costs applied to the expected customer load requirements will determine the minimum incremental revenue expected to be collected under this rate. Since the individualized rate development can be verified by Commission Staff, OTP can provide a price quote to the potential customer with increased speed and certainty. This process offers OTP the ability to react to business opportunities and to potentially serve customers in our North Dakota service territory.

Q. PLEASE DESCRIBE YOUR PROPOSED SLGS RATE

A. The proposed SLGS rate is shown in proposed Rate Schedule 10.06, included in Volume 2D. The rate schedule follows a similar design and headings as our other approved schedules, with a few exceptions, as noted.

- Standard Rate Design Headings/Sections:
  - Description of Service Levels and Rate Codes for Revenue/Sales Tracking
  - Regulations, Application of Rider, and Mandatory and Voluntary Riders
- Non-Standard or Expanded Rate Design Headings/Sections:
  - Scope of Rate Schedule: This non-standard addition is used to communicate the purpose of the SLGS rate. Most importantly, it states the rate schedule provides net benefits to all ratepayers and the use/intention of marginal costs.
  - Commission-Approved Process: As noted above, OTP is seeking a pre-approved process for improved speed and price certainty to assist businesses in becoming a part of North Dakota and its communities. Therefore, it is vital for the public to understand that OTP must seek approval of rate quotes and final rates.
  - Rate Determination: This item communicates to prospective customers that marginal costs are utilized to develop the individualized rates, with

revenue expectations to support the scope of the rate schedule: namely provide net benefits to ratepayers, at or above OTP's marginal costs.

- Terms and Conditions: This section is typical but the content is very important for prospective SLGS rate eligibility and company compliance.

Q. PLEASE COMPARE THE SLGS RATE PROPOSAL TO OTP'S PROPOSED ECONOMIC DEVELOPMENT RIDER.

A. OTP filed an Economic Development Rider (EDR) in late May 2017 (approval pending).[8] Both rate proposals[9] fulfill a similar goal: attract business customers into OTP's service territory and provide net benefits to its ratepayers. Both the EDR and SLGS rate utilize the marginal cost-to-serve model, customer load data, and OTP's standard rates and riders. The differences are by design: the EDR is designed to offer customer-specific, marginal cost-based discounts on OTP's existing rates for a period of up to 5 years, whereas the SLGS offers individualized rates designed upon marginal costs to serve and can be applied indefinitely, although the customer has the ability to return to existing standard rates or to a real time pricing rate after a period of 5 years.

Q. WHAT IS THE RELEVANT TIMEFRAME FOR THE MARGINAL COST ANALYSIS?

A. The relevant time-frame for the marginal cost analysis depends on the term of the SLGS rate, *i.e.*, the period before any changes to price are made. The risk of SLGS rates falling significantly below actual marginal generation costs may be relatively low if SLGS rates are updated every three to five years.

C. Generation Cost Recovery Rider

Q. PLEASE PROVIDE A SUMMARY OF THE PROPOSED GENERATION COST RECOVERY RIDER

A. The proposed Generation Cost Recovery Rider (GCRR), Section 13.06, is a new recovery

[8] Case No. PU-17-238.
[9] OTP engaged the services of NH Regulatory Consulting LLC for both EDR & SLGS proposals.

mechanism dedicated to recovering generation additions. As Mr. Tommerdahl describes, the GCRR is similar to OTP's current Transmission, Environmental, and Renewable Resource recovery riders. The GCRR recovery mechanism will recover costs associated with OTP's proposed Astoria Station generation project. OTP is only proposing to establish the recovery mechanism framework in this case – not to establish a rate.

Q. PLEASE DESCRIBE THE PROPOSED GENERATION COST RECOVERY FRAMEWORK

A. OTP's GCRR follows the same design as its current Environmental Cost Recovery Rider (ECRR) (recently updated and approved in Case No. PU-17-122). Like the ECRR, the proposed GCRR utilizes a cost recovery factor which will apply to customers' bills on a percentage basis. The GCRR will have its own tracker, annual revenue requirement, and true-up adjustment. Finally, OTP proposes the GCRR charges be included in the current "Energy and Renewable Adj" line item on the customers' bills.

Q. WHAT IS OTP'S PROPOSED GENERATION COST RECOVERY FACTOR?

A. The rate will initially be set at 0.000 percent. As Mr. Tommerdahl states, OTP will make a separate filing to request approval of recovery of the current and proposed costs, estimated to occur in late 2018 or early 2019.

D. LED Street and Area Lighting – Dusk to Dawn

Q. PLEASE PROVIDE A SUMMARY OF THE PROPOSED LED STREET AND AREA LIGHTING – DUSK TO DAWN SERVICE (LED LIGHTING SERVICE).

A. The proposed Light-Emitting Diode (LED) Lighting Service (Section 11.07) is a new lighting products schedule comprising of LED Outdoor and Flood lighting, Aluminum alloy poles, and a LED Floor Visor. Customers taking LED Lighting Service will receive the same service as provided under the current Lighting offerings (illumination service, including equipment installation, asset rental, electricity, and maintenance in a convenient, monthly charge on the customer's electric service bill). The LED Lighting Service, however, provides LED technology advantages over conventional High-Intensity Discharge (HID) lighting systems.

Q. PLEASE DESCRIBE THE ADVANTAGES LED LIGHTING HAS OVER HID LIGHTING.

A. The advantages are as follows:

1. **Equipment life.** LED fixture life in street and area lighting applications is often rated at 100,000 hours, where equivalent HID products operate with rated lives of only 10,000 to 24,000 hours.
2. **Lumen depreciation.** Lumen depreciation for most HID products can reach 50 percent, where most LED fixtures often operate at 70 percent of rated lumen output at end of rated life.
3. **Energy efficiency.** E Source reports that the average efficacy of 100-, 250- and 400-watt HID street and area lighting fixtures is about 61 lumens per watt. Equivalent LED fixtures operate at an average efficacy of 94 lumens per watt, or about 55 percent more efficiently, than HID.
4. **Light quality.** Today's LED fixtures operate at a much higher color rendering index (CRI) than most HID products, enabling drivers and pedestrians to more safely observe night time conditions due to improved light quality.

Q. WHY IS OTP MAKING THIS PROPOSAL?

A. OTP believes the time is right where prices for the technology are now reasonable, and the technology is a proven long-lasting efficient lighting solution. In addition, numerous North Dakota communities served by OTP are requesting LED lighting.

Q, WILL YOUR NEW LED FIXTURES BE COMPATIBLE WITH YOUR CURRENT OFFERINGS?

A. Yes. We have worked closely with our lighting supplier to provide compatibility with our existing offerings. OTP also took the opportunity to go further regarding our selections. We are aware some communities would like to meet Dark Sky Compliance rules. Because of their interest, we are adding a visor option for the proposed flood lights to limit light trespass and potential up-light. The products are known as "nighttime friendly"

and consistent with LEED[10]® goals and Green Globes[11]™ criteria for light pollution reduction.

Q. DID OTP SELECT NEW AND AVAILABLE LED TECHNOLOGIES WITH EQUIVALENT LIGHTING CHARACTERISTICS TO THE CURRENT STREET AND AREA LIGHTING OPTIONS?

A. Yes. OTP's Materials Engineering Department worked with our lighting supplier to develop a set of LED fixture offerings that handle the current lighting offering to a greatly reduced set of new LED technologies. The table below lists the current HID lighting type and the equivalent new replacement LED lighting types.

Table 25
Comparisons of HID and LED Lighting Types

Street and Area Lighting	
HID (OLD) Light Type	LED Equivalent Light Type
HPS9PT	LED3PT
MV6PT	LED3PT
HPS14	LED5
HPS9	LED5
MH8	LED5
MV6	LED5
HPS14PT	LED5PT
MH8PT	LED5PT
HPS19	LED8
MH14	LED8
HPS23	LED10
MH20	LED10
MV11	LED10
MV21	LED10
HPS44	LED13
MH110	LED13
MH36	LED13
MV35	LED13

Area Flood Lighting	
HID (OLD) Light Type	LED Equivalent Light Type
400 HPS	LED20FLOOD
400 MA	LED20FLOOD
400 MV	LED20FLOOD
SIGN	LED20FLOOD
1000-MA	LED30FLOOD
1000-MV	LED30FLOOD
1M-HPSF	LED30FLOOD

[10] Leadership in Energy and Environmental Design (LEED).
[11] The Green Globes system delivers an online assessment protocol, rating system and guidance for green building design, operation and management. It is interactive, flexible, and affordable, and provides market recognition of a building's environmental attributes through third-party verification.

Q. HOW DID OTP DESIGN THE LED LIGHTING SERVICE RATE?

A. OTP assessed the marginal cost of service for the proposed LED fixtures and pole offerings. The results of this study are included in Exhibit___(DGP-1), Schedule 8. This study calculated the proposed LED Lighting Service rates based on the capital and O&M costs of the new LED fixtures.

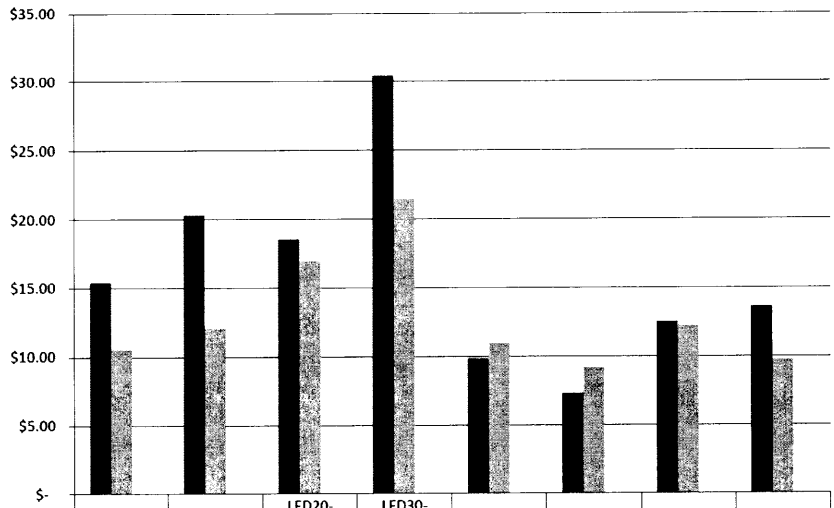
OTP then compared those marginal cost-based revenues to the embedded cost proposed revenues for the Lighting class. The goal is to design revenues so total Lighting class revenues are equal to those proposed by Ms. Ice. To reach that goal, we allocated the intra-class Lighting revenues to the different Lighting rate classes using a Weighted Average Method of Allocating revenue requirements for the current fixtures in the corresponding LED fixture types. Additional detail on this process is included in Schedule 8. This method was used over the EPMC method to limit the impact to customers, thereby making the transition to the LED lighting technology to be as smooth as possible.

Q. PLEASE DESCRIBE THE PROPOSED CUSTOMER BILL IMPACTS.

A. The figure below is an illustration of the relationship between the marginal cost-based rates for LED fixtures and the proposed LED Lighting Service rate.

Figure 17

Comparison of the proposed LED Rate options and Class Revenue Impact



	LED10	LED13	LED20-FLOOD	LED30-FLOOD	LED3PT	LED5	LED5PT	LED8
LED Weighted Monthly Rate Current	$15.44	$20.32	$18.56	$30.45	$9.83	$7.32	$12.53	$13.64
LED Marginal Cost based Rate	$10.56	$12.13	$17.01	$21.45	$11.00	$9.14	$12.21	$9.75
Class Revenue impact, %	5.0%	4.6%	17.1%	6.1%	2.4%	63.8%	0.3%	0.6%

The proposed LED5 type, which comprises the former lighting types, has the greatest proportion of revenue, at over 63 percent. In this transition, OTP proposes a balance of currently offered rates versus the marginal costs. Furthermore, not all marginal cost based prices are higher than the proposed prices, e.g. LED30-Flood, but overall, we believe have a balanced proposal to offer to our customers.

Q. PLEASE EXPLAIN OTP'S PLAN TO TRANSITION TO LED SERVICES.

A. OTP is proposing to close the Outdoor Lighting (Section 11.04) to new customers and replacements. Current customers will be served on the closed rate until their existing light fails. The new proposed LED Lighting Service (Section 11.07) will provide services to new customers and replacements.

E. Air Conditioning Rider

Q. PLEASE PROVIDE A SUMMARY OF THE PROPOSED ADDITION TO THE AIR CONDITIONING CONTROL RIDER.

A. OTP is proposing to add a new option to the existing Air Conditioning Control Rider for Commercial customers (only those customers taking service on Sections 10.01 and 10.02). This addition to the rider allows Commercial customers to reduce their summer peak demand obligation. By reducing peak demand obligations, OTP avoids unnecessary generation additions and helps to maintain lower energy costs for all customers.

Q. IS THE COMMERCIAL CUSTOMER INCENTIVE DIFFERENT THAN THE RESIDENTIAL CUSTOMER INCENTIVE?

A. Yes. OTP is proposing compensation that recognizes the differences between Residential and Commercial sized cooling systems and the difference in corresponding demand side benefits. Commercial cooling loads are more complex than typical Residential cooling systems with variability in system sizes, use of multiple units within a system, and use of multi-stage compressors per unit within systems. To account for this variability among Commercial customers' systems, a bill credit per ton of cooling capacity is warranted for Commercial customers.

Q. WHAT IS THE PROPOSED CREDIT FOR THE PROPOSED COMMERCIAL PROGRAM?

A. OTP proposes a credit of $6.00 per ton of cooling capacity, per month, during the program billing months of June through September. This credit amount is consistent with other utilities in the region, and consistent with pricing offered to OTP's Minnesota customers. Further it is significant enough to attract participation in the program.

Q. IS THIS CUSTOMER CREDIT FOR AIR CONDITIONING CONTROL COST EFFECTIVE?

A. Yes. OTP utilized DSMore™ to analyze this program. DSMore™ is an accepted evaluation tool for energy efficiency programs and can also be used to analyze demand response programs, including the Air Conditioning Control Rider. Preliminary analysis,

assuming 10 customers with 6 tons of cooling capacity each participate in the program, shows more benefits than costs (as indicated by a number greater than 1) across the five common benefit categories.

Table 26
Commercial Air Conditioning Rider Benefit/Cost Analysis

Benefit Category				
Participant	Ratepayer	Utility	Total Resource	Societal
Infinite	1.41	1.46	1.47	2.25

Q. WILL CONTROL METHODS BE CONSISTENT WITH RESIDENTIAL CONTROL?

A. Yes. The total hours of interruptions per year will not differ from the existing Residential program. We are proposing to add language to the Terms and Conditions to describe how control will be achieved on both single and dual stage air conditioning.

VI. TARIFF CHANGES OTHER THAN RATES

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

A. Yes. OTP is proposing improvements and updates to its rate book that clarify service conditions and other aspects of the rate book. All of the changes are reflected in the Matrix of Tariff Changes included as Exhibit___(DGP-1), Schedule 9.

These changes include cancelling the Released Energy Rider. The Released Energy Rider was put in place to protect OTP customers from extreme market prices that had materialized in certain hours during the infancy of the MISO market. Since that time, the MISO market has matured and the kind of market failures that caused extreme prices have been corrected. Other than one test in 2001, OTP has never used the Released Energy Rider. We therefore believe the Released Energy Rider is no longer necessary.

VII. CONCLUSION

Q. WHAT ARE YOUR CONCLUSIONS?

A. The facts presented in my Direct Testimony support the conclusions that:

- OTP's proposed rate design appropriately balances important considerations, including the cost of service and impact on customers;
- OTP's proposed rate components, included proposed fixed charges, are reasonable; and
- OTP's rate schedule changes should be adopted.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Mr. David G. Prazak, MPA
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Regulatory Services
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CURRENT RESPONSIBILITIES (2012 – Present)

Manage the design and implementation of retail pricing strategies for rate schedule and contract pricing, including rates, rate design, load research, revenue forecast, and tariff administration

PREVIOUS POSITIONS

Otter Tail Power Company

2012-Present	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's

Marginal Cost of Electric Service Study

October 26, 2017

Prepared by

NH Regulatory Consulting

Contents

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I. INTRODUCTION

Otter Tail Power Company (OTP) retained NH Regulatory Consulting to prepare an update of the 2015 company's system-wide marginal cost of electricity study (MCOS) for the time frame 2018 - 2022. This report describes the approach used for estimating marginal generation, transmission, distribution and customer-related costs, and presents the results. Economic theory holds that economic efficiency is maximized when customers respond to prices that reflect marginal costs. Marginal cost is defined as the change in total cost of service with respect to a small change in the demand of a product or service at any given time.

In an electricity ratemaking process, estimates of marginal generation, transmission and distribution costs may be used as a guide to determine revenue requirement allocations by class, decide on the appropriate rate components, and the level of time differentiation by costing period and seasons. Best practice electricity service marginal cost analysis requires identifying the utility's wholesale market where the utility operates, the system planning process, the latest capital expansion plan, including planned growth-related investment at the various levels of service, and expected impact of growth on utility system operations or contracting decisions. Marginal cost estimates were summarized for voltage level and each year and time-differentiated where appropriate.

II. MARGINAL GENERATION COSTS

As a member of the Midwest ISO's electricity wholesale market, OTP buys and sells on an hourly basis as required for achieving the lowest cost of serving its retail customers. In a competitive electricity market, the utility's marginal cost of generation associated with an increase in its retail demand is given by the market prices of energy, as well as the marginal cost of capacity if the change occurs at a time of system peak demand.

Estimating the marginal energy cost for each hour requires a forecast of market energy prices. Estimating the annual marginal cost of capacity requires an estimate of annual forward capacity prices in the MISO region and the specific MISO reserve margin rules. These prices are then converted into hourly marginal capacity costs and aggregated to time of use periods taking into account the estimated probability of peak by period. The costing periods that were used in the study are shown in Table 1.

Table 1. Time of Day and Seasonal Periods

Summer: June – September
Peak: Monday - Friday, 1 pm - 7 pm
Shoulder: Monday - Friday, 11 am - 1 pm and 7 pm - 10 pm; Weekends, 11 am – 10 pm
Off-Peak: Monday - Friday, 10 pm - 11 am; Weekends, 10 pm - 11 am
Winter: October – May
Peak: Monday - Friday, 7 am - 11 am
Shoulder: Monday - Friday, 6 am - 7 am, 11am- 10 pm; Weekends, 6 pm - 10 pm
Off-Peak: Monday - Friday, 10 pm - 6 am; Weekends, 10 pm - 6 pm

A. Marginal Energy Cost

An increment of native load in any hour requires OTP to purchase more energy or allows incremental energy sales to the market. MISO's forward monthly peak and off-peak prices[1] measured at the OTP node for the period January 2018 through Dec ember 2022 were used as a starting point. OTP developed the forward prices at the OTP node using a forecast of the price difference between the Indiana node and OTP node, based on 24 months of historical hourly price differentials.[2] We shaped the monthly energy peak and off-peak forward price at the OTP node using historical monthly averages of day-ahead hourly market prices for the period May 1, 2014 to July 31, 2017. The resulting forecasts of energy market prices for 2018-2022 were then averaged by costing period as per the definitions shown in Table 1 above.

The energy prices are quoted at the OTP Hub and thus losses need to be applied from that location to customer's meters at each voltage level of service. To convert market prices to energy marginal costs at customers' meters, we adjusted for the financial cost of working capital required and marginal energy losses incurred from the OTP hub to customer meters. Hourly losses were estimated from information on variable

[1] MISO On-peak period for purposes of the forward prices is Monday – Friday, hours ending 7-22. All other hours are off-peak.

[2] Intercontinental Exchange (ICE) provides forward prices for the Indiana node which is the main trading node in MISO.

losses at system peak load (from OTP's 2010 loss study) and year 2016 OTP's hourly control area loads.

B. Marginal Generation Capacity Cost

OTP procures capacity through bilateral capacity contracts and it expects to continue doing so to meet its obligations in the region through the study period (2018-2022).[3] The MCOS relied on the most up to date forecast of the regional market prices for capacity as a proxy for expected contract prices.

MISO establishes minimum planning reserve requirements for its members. As directed by Module E-1 of the MISO Tariff, MISO conducts a Loss of Load Expectation (LOLE) study that determines the required resources and Planning Reserve Margin (PRM) that would allow achieving the target LOLE level. MISO calculates a target PRM such that the LOLE for next planning year is 1 day in 10 years. MISO coordinates with stakeholders to determine the appropriate PRM taking into account the forecast of coincident peak loads and installed capacity resources ("PRM_{UCAP}") as well as a PRM on unforced capacity (PRM_{UCAP}) by adjusting the Installed Capacity PRM by the weighted average forced outage rate of all the regional resources.[4]

Under the existing construct, the PRM_{UCAP} is applied to the expected peak of each LSE coincident with the MISO peak. OTP's annual marginal cost of capacity cost is triggered by an increment of native load at the time of MISO coincident system peak, which may require OTP to reduce the size of a capacity sale or contract for additional resources. Thus, given MISO RA rules OTP's marginal generation capacity cost in any hour on a planning basis is a function of: (1) the forecast annual capacity price, which varies with the level of capacity surplus in the region, (2) the required PRM, and (3) the probability that each hour is MISO's system annual peak hour. While OTP is a winter peaking utility, MISO is mostly a summer-peaking region.

The calculation of OTP's marginal generation capacity cost took into account MISO's expected planning reserve margins for each year of the study period. For the current planning year 2017/18, ICAP reserve margin over the region-wide coincident peak

[3] The MCOS assumes that OTP is able to contract sufficient capacity to meet target PRM and do not rely on MISO voluntary annual capacity auction.

[4] MISO determines the UCAP value annually for each generating unit and then credits them their specific UCAP value for the purpose of meeting resource adequacy requirements.

demand is 15.8% and the PRM_{UCAP} is 7.8%.[5] Table 2 below shows the expected target PRMs by MISO. The MCOS uses PRM-ICAP percentages.[6]

Table 2. MISO Annual Planning Reserve Margins (2018-2022)

	2018	2019	2020	2021	2022	Average
PRM-ICAP	15.80%	15.60%	15.40%	15.50%	15.50%	15.6%
PRM-UCAP	7.80%	7.50%	7.30%	7.40%	7.50%	7.5%

The probability of peak analysis used MISO's historical hourly native loads for a historical 5-year period. Upon calculating probability of peak for each daytype and season, the MCOS estimated OTP's hourly marginal generation capacity costs, and adjusted them by marginal losses and working capital.

III. MARGINAL TRANSMISSION COST

OTP's transmission system consists of the Company's networked transmission, including 345 kV, 230 kV, 115 kV, 69 kV and 41.6 kV facilities. Transmission greater than 100 kV is under the functional control of MISO and included as part of the MISO regional transmission expansion plan. OTP has operational control of its transmission facilities at or below 100 kV and are included in the calculation of FERC-approved MISO Network Integration Transmission Service rate (NITS) for OTP's Control Area.[7] The Network Upgrade Charge (NUC) rate generally recovers the costs of new transmission facilities above 100 kV. 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

[5] "Planning Year 2017-2018 Loss of Load Expectation Study Report". MISO Loss of Load Expectation Working Group.

[6] OTP's MCOS uses the PRM icap percentage as opposed to PRM ucap since OTP's capacity price forecasts have not been adjusted to reflect expected forced outages or any planned maintenance.

[7] OTP operates in a joint pricing zone within the Midwest ISO. In addition to OTP's revenue requirement, NITS recovers the annual transmission revenue requirements for the Great River Energy (GRE) facilities located in the OTP Pricing Zone and for OTP transmission facilities.

method that differs between economic and reliability projects.[8] For transmission projects rated below 345-kV, all costs get allocated on a zonal basis and then each individual pricing zone based on each zone's contribution to MISO's 12 CPs.

A. Network Integration Transmission Service Rate

The NITS rate is recovered from each transmission user[9] in the OTP Pricing Zone based on their monthly coincident peak loads. From the point of view of OTP, the marginal cost of transmission is reflected by the impact of an increase in monthly coincident peak on its MISO transmission bill. These charges are a financial marginal cost to OTP. The MISO NITS and NUC charges are constant every month, as they reflect 1/12 of the applicable annual revenue requirement per kW.

The starting point for the financial marginal transmission cost in MCOS was 2017 OTP's NITS rate. Estimating the change in NITS charges beyond 2017 required identifying the projected annual increase in NITS revenue requirement associated with OTP's applicable new transmission projects, using OTP budgets for 115-kV (below $5 million), 41.6 and 69 kV projects expected to come into service in the period 2018-2022, and excluding the projects that qualify for transmission cost rider (TCR). MISO's estimates of annual carrying charges were applied to the budget figures to compute an annual incremental revenue requirement for the OTP Pricing Zone NITS and divided by the forecast of 12 monthly OTP's control area CPs to compute an annual per-kW NITS charge.

B. Network Upgrade Charge Rate

To estimate the second component of the financial transmission marginal cost, the NUC rate, MCOS relied on MISO's calculation of projected annual revenue requirement as per Schedule 26. The total NUC transmission revenue requirement allocated to the OTP Pricing Zone is the sum of a system-wide allocation, a sub-regional allocation, and the individual allocations corresponding to new projects. To estimate the NUC charges corresponding to the OTP Pricing Zone for the period 2018 through 2022, MISO's projections of the NUC-related annual incremental transmission revenue requirements that have been allocated to OTP's pricing zone were divided by

[8] To qualify for regional cost sharing under a postage stamp rate, both Baseline Reliability Projects and Regionally Beneficial Projects must include facilities 345kV and above.

[9] Except for certain grandfathered transmission agreements.

the expected 12 monthly coincident peak forecast in each year used. The total dollar revenue requirement amount is then divided by the sum of 12 CPs in the OTP zone to establish the corresponding NUC rate forecast.

Because both the NITS and NUC charges are assessed on the basis of a transmission user's monthly peak demands, the MCOS allocated the monthly transmission cost to hours using the probability of a given hour's being the monthly peak. These probabilities relied on four years of OTP Control Area's historical hourly loads. The results were adjusted by losses and cash working capital. The 2018 marginal transmission costs stated on a per kWh and kW basis are shown in the summary tables at the end of the report.

IV. MARGINAL ANCILLARY SERVICE COSTS

MISO implemented ancillary services markets (ASM) in January 2009. Prior to January 2009, all ancillary services for Otter Tail were self-provided. The costs of ancillary services are also marginal financial costs to OTP. Two types of ancillary services provided via these markets are Regulation and Operating Reserves (Spinning and Supplemental). OTP pays an hourly rate that is the total cost of each of these services procured by the MISO divided by the total hourly MISO load. OTP provided an average annual cost for each type of service for 2016. A forecast of the hourly cost of these services for future years was not available. The expected cost was adjusted by marginal losses at each service voltage level and working capital.

V. MARGINAL DISTRIBUTION COSTS

The various components of OTP's distribution system include distribution substations, primary feeders, local distribution facilities such as secondary lines, primary-to-secondary transformers and switchgear and local primary taps, dedicated feeders used by some large primary customers;[10] and service drops. The service drop in most cases serves a single customer. The MCOS treated the service, along with the meter and associated equipment such as current transformer as part of the marginal customer cost for each class.

A. Distribution Substation and Trunkline Feeder Costs

Stations and trunkline feeders from the substation to the point where the line branches to create a primary tap line is expanded as distribution area peak demands grow. Estimating the marginal cost of distribution substation and trunkline feeder expansion per kW of demand, required identifying the cost of budgeted growth-related projects from OTP's capital expansion plan for the period 2018-2022. The sum of OTP's growth-related investment (in 2018 dollars) was divided by the estimated addition to distribution substation non-coincident peak demand over the same period. [11]

Distribution O&M expenses are a component of marginal distribution cost, since they grow with the amount of plant in service. The MCOS allocated OTP's FERC Form 1 distribution O&M expenses by FERC account for 2012-2016 annual distribution substation O&M expenses, plus associated overheads, were divided by estimates of the sum of non-coincident peak demands at the substations and converted to 2018 dollars. After reviewing the trend in expense per kW (in constant dollars), the average of the 2014-2016 values was considered a reasonable proxy for marginal substation O&M expenses.

To time differentiate this component, the relative probability of peak for months, day-types (weekdays, Saturday, and Sunday) were estimated based on historical hourly loads on all of OTP distribution substations for the years 2010-2014. The analysis

[10] This study does not calculate separate marginal costs for such customers, since the costs are recovered outside of standard rates.

[11] OTP was only able to provide non-coincident distribution peak demand for 2016. We estimated OTP's NCP for the period 2018-2022 based on expected growth rate of OTP's annual peak demands.

accounted for the relative lower carrying capability of this equipment in summer months as compared to the winter.

B. Local Distribution Facility Costs

Local distribution facilities, including secondary lines, transformers, and a portion of primary taps, are less extensively shared and are designed using engineering standards that take into consideration the expected number of customers connected and their maximum expected loads over the life of the facilities. Different design standards are used for local distribution systems in rural versus urban areas, and for customers that use all electric appliances instead of relying partially on gas. In general the marginal cost of local distribution facilities is incurred based on design demand, not customer's actual peak load from month to month. Local distribution facilities for commercial and industrial customers are generally designed on a case-by-case basis, taking into consideration the expected long-term peak demand.

OTP provided estimates of the typical investment in local distribution facilities for various types and sizes of customers, by applying its standard distribution cost estimation to a range of typical customer characteristics.[12] The MCOS estimated marginal costs as fixed monthly cost per kW of design demand. The transformer capacity divided by the number of customers served from that transformer was used as a proxy for the estimated design demand by class.

The MCOS also estimated marginal distribution facility O&M from historical data given that there was not a forecast of O&M expenses. The average of 2014 -2016 expense per kW of design demand, separated into primary and secondary categories on the basis of miles of circuit, was used as the estimated marginal distribution facilities O&M expense. The total design demand was the product of customer counts and per-customer design demand estimates by customer category, developed by OTP from load survey data for years 2015 and 2016.

OTP books expenses for both lighting facilities and distribution facilities used by lights in the FERC lighting O&M accounts. The MCOS used the average expense during the period 2014-2016 as the estimate of the marginal level of these expenses.

[12] OTP also used this approach to estimate the cost of customer service drops.

VI. MARGINAL CUSTOMER COSTS

A. Meter and Service Costs

OTP provided the current installed cost of a typical meter, including current transformerif applicable, and service drop for customer categories. The labor cost components of these costs were adjusted to account for expected annual increase of 3% to state them in 2018 dollars. The average expense in 2015 and 2016 was used to represent the marginal level of these expenses.

Meter requirements for small power producers 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 costs of installing these meters. The MCOS calculated an annual installed bi-directional meter cost incremental to the regular meter cost, by rate category.

B. Customer Accounts and Customer Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are costs that are the function of a number of customers on the system. OTP's FERC Form 1 historical customer account and service expense levels for the period 2012-2016 were divided by class weighted customers to obtain an estimate of customer accounts expense per weighted customer. After considering the declining trend in expenses, the average expense per customer in 2015 and 2016 was used as an estimate of marginal expense.

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.[13] The same procedure used for customer accounts expenses was followed using the class weights developed from OTP's 2017 embedded cost of service study. Given the decrease of unit expense per customer observed in recent years, the average of 2014 through 2016 values was assumed to be a reasonable approximation of the estimated future marginal expense.

[13] Expenses associated with CIP and EEP, programs mandated by Minnesota and South Dakota to promote demand side measures, were omitted from the marginal cost calculations since these costs are intended to reduce energy and capacity costs.

C. One-time customer cost for Small Power Producer

Customers under the Small Power Producer Rider are responsible for system upgrades caused by the installation of the generation system. The most important one-time cost impact is related to the interconnection process, i.e., processing and energizing the interconnection. OTP does not currently charge any fee directly associated with the incremental expenses involved with this work and so this cost is currently shared by all customers. The MCOS estimated a typical one-time cost of interconnecting a small power producer involved estimating the time to review the application form filled out by customer, a site inspection, an interconnection study and conclusion, and a final site visit prior to the energizing of the generator.

The labor cost reflects the mid-point of the expected 2018 average hourly salary of the employees directly involved in handling the interconnection assuming. This hourly cost was then multiplied by the 20 hours typically required to process the interconnection, excluding the time required to install a bi-directional meter, which is computed separately. The cost was then adjusted for non-plant related loaders and cash working capital.

VII. COMPUTATION OF ANNUAL MARGINAL COSTS

The MCOS estimated marginal annualized cost for each component of service by adjusting the investment per unit by the general plant loading factor. We multiplied the resulting figures by the annual economic carrying charge percentage and added a plant-related A&G loading factor to yield the annualized plant costs. To these costs, associated O&M and non-plant related A&G expenses, and revenue requirements for working capital are added to finalize the computation of annualized costs. The computation of working capital includes components for cash, materials, supplies and prepayments. The working capital needs were estimated based on recent historical amounts. The revenue requirement for this working capital was developed from OTP's weighted average cost of capital plus an income tax component that recognizes that the equity portion of return on capital is taxable. Appendix 2 includes the derivation of the annual distribution substation and trunkline feeder costs, the development of the annual marginal cost for local distribution facilities and lighting, and the derivation of annualized cost of meters and service drops, as well as other annualized marginal customer-related expenses.

A. Loaders

Marginal cost estimates need to be adjusted by either plant-related A&G, non-plant-related A&G or general plant loading factors as required to capture the additional plant or O&M expenses, or overhead costs incurred when electric plant or electric O&M increase. Certain administrative and general (A&G) expenses can grow either with plant or with O&M expenses. Accounts not marginal with respect to other expenses or plant must be excluded.[14]

A non-plant-related A&G loader was 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 1982-2014, or 13.23%. For plant-related A&G, there are two A&G FERC accounts clearly vary with the amount of plant in service: Maintenance of General Plant (FERC Account 935) and Property Insurance (FERC Account 924). Account 935 was regressed on cumulative net additions to total electric plant, all in constant dollars, for the period 1982 to 2014, yielding a loader of 0.10%. A second component of plant-related A&G was average property and terrorism insurance rate, $0.0729 per $100 or 0.0729%. The total plant-related A&G loader applicable to distribution substations was 0.17%, and 0.10% for all other distribution plant that does not require insurance.

General plant typically grows with other types of plant. General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. Since 1996 there has been very little change in OTP's general plant. A regression of cumulative net additions to general plant on cumulative net additions to total plant (less general plant) using data from 1996-2014 resulted in a General Plant loader of 1.30%.

B. Economic Carrying Charges

To be useful in ratemaking and other marginal cost applications, estimates of marginal investment in several categories of distribution plant investment must be converted into annual costs using an economic carrying charge. The annual charge reflects the elements of OTP's revenue requirement associated with incremental plant. Key inputs for 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

[14] OTP's MC study excluded FERC Accounts 922 Administrative Expenses Transferred (Credit), 923 Outside Services Employed, 927 Franchise Requirements, 928 Regulatory Requirements, 930.1 Institutional and Goodwill Advertising Expenses, and 931 Rents.

expected inflation rate for that type of plant, net of technical progress, and the average service life and patterns of failure ("Iowa curve") for that type of plant. OTP provided 3.0 percent as an approximation of the rate of future inflation, based on its 10-year financial model. OTP foresees financing of incremental investment through sales of common stock (52.44%) and debt (47.56%). The long-term incremental cost of debt is expected to be 5.05% and the incremental cost of common stock is expected to be 9.50%. The resulting economic carrying charges are presented below.

Table 2. Economic Carrying Charges

	Distribution Substation (1)	Distribution Facilities (2)	Meters (3)
(1) Present Value of Revenue Requirements Related to Incremental $1,000 Investment	$1,429.76	$1,467.31	$1,413.82
(2) Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment	$177.79	$26.34	$75.89
(3) Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2)	$1,607.55	$1,493.65	$1,489.71
(4) First-Year Annual Economic Charge Related to Incremental $1,000 Investment	$74.69	$63.66	$91.45
(5) First-Year Annual Economic Charge Related to Incremental Investment [(4)/$1,000]	7.47%	6.37%	9.14%

C. Demand losses

Marginal capacity losses are applied to distribution substation and trunkline feeder costs to reflect the fact that, to accommodate a kW of additional peak load at the customer's meter, facilities must be expanded by successively more than a kW as you move up the distribution system to accommodate the fixed and variable losses on the system in the peak hour. Peak demand loss factors were developed from OTP's 2010 loss study. The loss-adjusted costs are then time-differentiated, using estimates of the relative probability of distribution substation peak.

VIII. SUMMARY OF MARGINAL COSTS FOR YEARS 2018 - 2022

The results of time-differentiated costs (including energy, generation capacity, transmission and distribution substation costs) on a per-kWh basis and on a per-kW basis, averaged over the hours in the period and for each year are shown in Tables 3 through 12 below.

Table 3. 2018 Summary of Time-differentiated Marginal Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2018 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Energy	4.1280	3.0849	1.9980	3.5766	3.1773	2.1663
Generation Capacity	7.0240	0.9055	0.0147	0.0018	0.0014	0.0000
Regulation and Op. Reserves	0.0863	0.0863	0.0863	0.0863	0.0863	0.0863
Transmission	3.9633	0.3757	0.0062	5.0471	0.5198	0.0911
Distribution Substation	4.1771	0.1404	0.0008	0.0000	0.0000	0.0000
Total	19.3787	4.5927	2.1060	8.7117	3.7848	2.3436
Seasonal	5.8861			3.6851		
Annual	4.4207					
(2) **Primary**						
Energy	3.9747	2.9799	1.9393	3.4241	3.0528	2.0883
Generation Capacity	6.7235	0.8669	0.0140	0.0017	0.0013	0.0000
Regulation and Op. Reserves	0.0843	0.0843	0.0843	0.0843	0.0843	0.0843
Transmission	3.7955	0.3597	0.0059	4.7856	0.4912	0.0858
Distribution Substation	4.0621	0.1366	0.0008	0.0000	0.0000	0.0000
Total	18.6402	4.4273	2.0444	8.2957	3.6297	2.2584
Seasonal	5.6746			3.5322		
Annual	4.2483					
(3) **Transmission**						
Energy	3.7304	2.8110	1.8438	3.1850	2.8557	1.9640
Generation Capacity	6.2510	0.8062	0.0131	0.0015	0.0012	0.0000
Regulation and Op. Reserves	0.0809	0.0809	0.0809	0.0809	0.0809	0.0809
Transmission	3.5314	0.3345	0.0055	4.3853	0.4479	0.0778
Distribution Substation						
Total	13.5937	4.0326	1.9432	7.6527	3.3857	2.1227
Seasonal	4.6082			3.2922		
Annual	3.7321					

Table 4. 2018 Summary of Marginal Time-Differentiated Costs per-kW

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Monthly Costs per Kilowatt (2018 Dollars per Kilowatt)						
Generation Capacity	$9.181	$1.854	$0.058	$0.002	$0.004	$0.000
Transmission	$5.181	$0.769	$0.025	$4.380	$1.534	$0.316
Distribution Substation	$5.460	$0.288	$0.003	$0.000	$0.000	$0.000
Total	$19.82	$2.91	$0.09	$4.38	$1.54	$0.32
Seasonal	$22.82			$6.24		
Annual	$11.76					
(2) **Primary**						
Monthly Costs per Kilowatt (2018 Dollars per Kilowatt)						
Generation Capacity	$8.789	$1.775	$0.056	$0.001	$0.004	$0.000
Transmission	$4.961	$0.737	$0.023	$4.153	$1.450	$0.298
Distribution Substation	$5.310	$0.280	$0.003	$0.000	$0.000	$0.000
Total	$19.06	$2.79	$0.08	$4.15	$1.45	$0.30
Seasonal	$21.93			$5.91		
Annual	$11.25					
(3) **Transmission**						
Monthly Costs per Kilowatt (2018 Dollars per Kilowatt)						
Generation Capacity	$8.171	$1.651	$0.052	$0.001	$0.004	$0.000
Transmission	$4.616	$0.685	$0.022	$3.806	$1.322	$0.270
Distribution Substation						
Total	$12.79	$2.34	$0.07	$3.81	$1.33	$0.27
Seasonal	$15.20			$5.40		
Annual	$8.67					

Table 5. 2019 Summary of Time-differentiated Marginal Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2019 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Energy	4.0044	3.0282	1.9776	3.4868	3.0948	2.1316
Generation Capacity	15.5895	2.0097	0.0325	0.0039	0.0031	0.0000
Regulation and Op. Reserves	0.0888	0.0888	0.0888	0.0888	0.0888	0.0888
Transmission	3.9196	0.3715	0.0061	4.9915	0.5141	0.0901
Distribution Substation	4.3024	0.1446	0.0009	0.0000	0.0000	0.0000
Total	27.9048	5.6429	2.1059	8.5711	3.7008	2.3106
Seasonal	7.7024			3.6186		
Annual	4.9836					
(2) **Primary**						
Energy	3.8555	2.9252	1.9196	3.3373	2.9728	2.0546
Generation Capacity	14.9226	1.9241	0.0311	0.0037	0.0029	0.0000
Regulation and Op. Reserves	0.0868	0.0868	0.0868	0.0868	0.0868	0.0868
Transmission	3.7537	0.3557	0.0059	4.7328	0.4858	0.0849
Distribution Substation	4.1839	0.1406	0.0008	0.0000	0.0000	0.0000
Total	26.8026	5.4324	2.0443	8.1607	3.5484	2.2263
Seasonal	7.4133			3.4679		
Annual	4.7867					
(3) **Transmission**						
Energy	3.6183	2.7595	1.8253	3.1031	2.7799	1.9318
Generation Capacity	13.8739	1.7893	0.0290	0.0034	0.0027	0.0000
Regulation and Op. Reserves	0.0833	0.0833	0.0833	0.0833	0.0833	0.0833
Transmission	3.4925	0.3308	0.0054	4.3370	0.4429	0.0770
Distribution Substation						
Total	21.0680	4.9629	1.9430	7.5268	3.3088	2.0921
Seasonal	6.2031			3.2316		
Annual	4.2248					

Table 6. 2019 Summary of Marginal Time-Differentiated Costs per kW

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Monthly Costs per Kilowatt (2019 Dollars per Kilowatt)						
Generation Capacity	$20.378	$4.116	$0.129	$0.003	$0.009	$0.000
Transmission	$5.124	$0.761	$0.024	$4.332	$1.517	$0.313
Distribution Substation	$5.624	$0.296	$0.003	$0.000	$0.000	$0.000
Total	$31.13	$5.17	$0.16	$4.34	$1.53	$0.31
Seasonal	$36.45			$6.17		
Annual	$16.27					
(2) **Primary**						
Monthly Costs per Kilowatt (2019 Dollars per Kilowatt)						
Generation Capacity	$19.506	$3.940	$0.123	$0.003	$0.009	$0.000
Transmission	$4.907	$0.728	$0.023	$4.107	$1.434	$0.295
Distribution Substation	$5.469	$0.288	$0.003	$0.000	$0.000	$0.000
Total	$29.88	$4.96	$0.15	$4.11	$1.44	$0.29
Seasonal	$34.99			$5.85		
Annual	$15.56					
(3) **Transmission**						
Monthly Costs per Kilowatt (2019 Dollars per Kilowatt)						
Generation Capacity	$18.135	$3.664	$0.115	$0.003	$0.008	$0.000
Transmission	$4.565	$0.678	$0.022	$3.764	$1.307	$0.267
Distribution Substation						
Total	$22.70	$4.34	$0.14	$3.77	$1.31	$0.27
Seasonal	$27.18			$5.35		
Annual	$12.63					

Table 7. 2020 Summary of Time-differentiated Marginal Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2020 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Energy	4.0255	3.0317	1.9717	3.3931	3.0124	2.1232
Generation Capacity	18.6207	2.4005	0.0389	0.0047	0.0037	0.0000
Regulation and Op. Reserves	0.0915	0.0915	0.0915	0.0915	0.0915	0.0915
Transmission	3.8625	0.3661	0.0060	4.9188	0.5066	0.0888
Distribution Substation	4.4315	0.1490	0.0009	0.0000	0.0000	0.0000
Total	31.0318	6.0388	2.1090	8.4081	3.6142	2.3035
Seasonal	8.3732			3.5608		
Annual	5.1693					
(2) **Primary**						
Energy	3.8758	2.9284	1.9139	3.2475	2.8935	2.0466
Generation Capacity	17.8241	2.2982	0.0372	0.0044	0.0035	0.0000
Regulation and Op. Reserves	0.0894	0.0894	0.0894	0.0894	0.0894	0.0894
Transmission	3.6990	0.3505	0.0058	4.6639	0.4787	0.0836
Distribution Substation	4.3094	0.1449	0.0009	0.0000	0.0000	0.0000
Total	29.7978	5.8115	2.0472	8.0053	3.4653	2.2197
Seasonal	8.0557			3.4126		
Annual	4.9646					
(3) **Transmission**						
Energy	3.6370	2.7624	1.8197	3.0194	2.7056	1.9245
Generation Capacity	16.5715	2.1372	0.0346	0.0040	0.0032	0.0000
Regulation and Op. Reserves	0.0858	0.0858	0.0858	0.0858	0.0858	0.0858
Transmission	3.4416	0.3260	0.0054	4.2738	0.4365	0.0758
Distribution Substation						
Total	23.7359	5.3115	1.9455	7.3830	3.2311	2.0862
Seasonal	6.7783			3.1802		
Annual	4.3829					

Table 8. 2020 Summary of Marginal Time-Differentiated Costs per kW

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Monthly Costs per Kilowatt (2020 Dollars per Kilowatt)						
Generation Capacity	$24.340	$4.916	$0.154	$0.004	$0.011	$0.000
Transmission	$5.049	$0.750	$0.024	$4.269	$1.495	$0.308
Distribution Substation	$5.793	$0.305	$0.003	$0.000	$0.000	$0.000
Total	$35.18	$5.97	$0.18	$4.27	$1.51	$0.31
Seasonal	$41.33			$6.09		
Annual	$17.84					
(2) **Primary**						
Monthly Costs per Kilowatt (2020 Dollars per Kilowatt)						
Generation Capacity	$23.299	$4.706	$0.147	$0.004	$0.010	$0.000
Transmission	$4.835	$0.718	$0.023	$4.048	$1.413	$0.290
Distribution Substation	$5.633	$0.297	$0.003	$0.000	$0.000	$0.000
Total	$33.77	$5.72	$0.17	$4.05	$1.42	$0.29
Seasonal	$39.66			$5.76		
Annual	$17.06					
(3) **Transmission**						
Monthly Costs per Kilowatt (2020 Dollars per Kilowatt)						
Generation Capacity	$21.661	$4.377	$0.137	$0.003	$0.009	$0.000
Transmission	$4.499	$0.668	$0.021	$3.709	$1.288	$0.263
Distribution Substation						
Total	$26.16	$5.04	$0.16	$3.71	$1.30	$0.26
Seasonal	$31.36			$5.27		
Annual	$13.97					

Table 9. 2021 Summary of Time-differentiated Marginal Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2021 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Energy	3.8734	2.9366	1.9083	3.4626	3.0701	2.1003
Generation Capacity	18.8635	2.4318	0.0394	0.0048	0.0038	0.0000
Regulation and Op. Reserves	0.0943	0.0943	0.0943	0.0943	0.0943	0.0943
Transmission	3.7911	0.3593	0.0059	4.8278	0.4972	0.0871
Distribution Substation	4.5645	0.1534	0.0009	0.0000	0.0000	0.0000
Total	31.1867	5.9754	2.0487	8.3893	3.6653	2.2818
Seasonal	8.3505			3.5689		
Annual	5.1671					
(2) **Primary**						
Energy	3.7295	2.8367	1.8524	3.3144	2.9493	2.0246
Generation Capacity	18.0566	2.3281	0.0377	0.0045	0.0035	0.0000
Regulation and Op. Reserves	0.0921	0.0921	0.0921	0.0921	0.0921	0.0921
Transmission	3.6305	0.3440	0.0000	4.5776	0.4699	0.0821
Distribution Substation	4.4387	0.1492	0.0009	0.0000	0.0000	0.0000
Total	29.9474	5.7503	1.9831	7.9885	3.5149	2.1988
Seasonal	8.0306			3.4208		
Annual	4.9616					
(3) **Transmission**						
Energy	3.4999	2.6761	1.7614	3.0820	2.7582	1.9038
Generation Capacity	16.7876	2.1651	0.0351	0.0041	0.0032	0.0000
Regulation and Op. Reserves	0.0884	0.0884	0.0884	0.0884	0.0884	0.0884
Operating Reserve	0.0526	0.0526	0.0526	0.0526	0.0526	0.0526
Transmission	3.3779	0.3200	0.0053	4.1947	0.4284	0.0744
Distribution Substation						
Total	23.8064	5.3021	1.9427	7.4218	3.3308	2.1192
Seasonal	6.7868			3.2409		
Annual	4.4261					

Table 10. 2021 Summary of Marginal Time-Differentiated Costs per kW

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Monthly Costs per Kilowatt (2021 Dollars per Kilowatt)						
Generation Capacity	$24.657	$4.980	$0.156	$0.004	$0.011	$0.000
Transmission	$4.955	$0.736	$0.023	$4.190	$1.467	$0.302
Distribution Substation	$5.966	$0.314	$0.004	$0.000	$0.000	$0.000
Total	$35.58	$6.03	$0.18	$4.19	$1.48	$0.30
Seasonal	$41.79			$5.97		
Annual	$17.91					
(2) **Primary**						
Monthly Costs per Kilowatt (2021 Dollars per Kilowatt)						
Generation Capacity	$23.603	$4.768	$0.149	$0.004	$0.010	$0.000
Transmission	$4.746	$0.705	$0.000	$3.973	$1.386	$0.285
Distribution Substation	$5.802	$0.306	$0.003	$0.000	$0.000	$0.000
Total	$34.15	$5.78	$0.15	$3.98	$1.40	$0.29
Seasonal	$40.08			$5.66		
Annual	$17.13					
(3) **Transmission**						
Monthly Costs per Kilowatt (2021 Dollars per Kilowatt)						
Generation Capacity	$21.944	$4.434	$0.139	$0.004	$0.009	$0.000
Transmission	$4.415	$0.655	$0.021	$3.640	$1.264	$0.258
Distribution Substation						
Total	$26.36	$5.09	$0.16	$3.64	$1.27	$0.26
Seasonal	$31.61			$5.18		
Annual	$13.99					

Table 11. 2022 Summary of Time-differentiated Marginal Costs per kWh

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(2022 Cents per kWh)					
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Energy	3.9477	3.0113	1.9819	3.5345	3.1424	2.1820
Generation Capacity	19.1356	2.4669	0.0399	0.0048	0.0038	0.0000
Regulation and Op. Reserves	0.0971	0.0971	0.0971	0.0971	0.0971	0.0971
Transmission	3.7750	0.3578	0.0059	4.8073	0.4951	0.0868
Distribution Substation	4.7014	0.1580	0.0009	0.0000	0.0000	0.0000
Total	31.6568	6.0911	2.1258	8.4438	3.7384	2.3659
Seasonal	8.5085			3.6450		
Annual	5.2706					
(2) **Primary**						
Energy	3.8010	2.9089	1.9240	3.3832	3.0187	2.1033
Generation Capacity	18.3170	2.3617	0.0382	0.0046	0.0036	0.0000
Regulation and Op. Reserves	0.0949	0.0949	0.0949	0.0949	0.0949	0.0949
Transmission	3.6152	0.3426	0.0056	4.5582	0.4679	0.0817
Distribution Substation	4.5719	0.1537	0.0009	0.0000	0.0000	0.0000
Total	30.4000	5.8618	2.0636	8.0409	3.5851	2.2800
Seasonal	8.1863			3.4941		
Annual	5.0624					
(3) **Transmission**						
Energy	3.5671	2.7442	1.8296	3.1461	2.8231	1.9779
Generation Capacity	17.0297	2.1963	0.0356	0.0041	0.0033	0.2933
Regulation and Op. Reserves	0.0910	0.0910	0.0910	0.0910	0.0910	0.0910
Transmission	3.3637	0.3186	0.0052	4.1770	0.4266	0.0741
Distribution Substation						
Total	24.0515	5.3502	1.9614	7.4182	3.3440	2.4364
Seasonal	6.8541			3.3968		
Annual	4.5524					

Table 12. 2022 Summary of Marginal Time-Differentiated Costs per kW

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Monthly Costs per Kilowatt (2022 Dollars per Kilowatt)						
Generation Capacity	$25.013	$5.052	$0.158	$0.004	$0.011	$0.000
Transmission	$4.934	$0.733	$0.023	$4.172	$1.461	$0.301
Distribution Substation	$6.145	$0.324	$0.004	$0.000	$0.000	$0.000
Total	$36.09	$6.11	$0.19	$4.18	$1.47	$0.30
Seasonal	$42.39			$5.95		
Annual	$18.10					
(2) **Primary**						
Monthly Costs per Kilowatt (2022 Dollars per Kilowatt)						
Generation Capacity	$23.943	$4.836	$0.152	$0.004	$0.011	$0.000
Transmission	$4.726	$0.702	$0.022	$3.956	$1.381	$0.284
Distribution Substation	$5.976	$0.315	$0.004	$0.000	$0.000	$0.000
Total	$34.64	$5.85	$0.18	$3.96	$1.39	$0.28
Seasonal	$40.67			$5.64		
Annual	$17.32					
(3) **Transmission**						
Monthly Costs per Kilowatt (2022 Dollars per Kilowatt)						
Generation Capacity	$22.260	$4.498	$0.141	$0.004	$0.010	$0.000
Transmission	$4.397	$0.653	$0.021	$3.625	$1.259	$0.257
Distribution Substation						
Total	$26.66	$5.15	$0.16	$3.63	$1.27	$0.26
Seasonal	$31.97			$5.15		
Annual	$14.09					

Table 13 summarizes monthly marginal local distribution facilities costs per kW of design demand and on a per customer basis, by class.

Table 13: Summary of Monthly Marginal Local Distribution Facilities (and Lighting) Costs

	Customer Class	Monthly Facility Cost per kW of Design Demand ($/kW) (1)	Estimate of Typical Design Demand by Customer kW (2)	Monthly Facility Cost per Customer ($/customer/mo.) (1)*(2) (3)
	Residential			
(1)	Urban	$1.40	8	$11.69
(2)	Rural	$2.63	18	46.11
(3)	Apartment, Gas	$1.24	5	5.61
(4)	Apartment, Elec	$0.89	9	8.08
(5)	**Farm**	$2.67	18	46.65
	Small Commercial			
(6)	Stand-Alone customer, overhead	$0.69	50	34.64
(7)	Stand-Alone customer 3ph, overhead	$0.83	75	62.61
	Shared-customer 3ph, overhead	$0.89	75	66.67
	Stand-Alone customer, underground	$1.13	50	56.63
(8)	Stand-Alone 3ph, underground	$1.34	75	100.37
	Large Commercial (Secondary)			
(9)	101-150kVa, 3ph	$0.99	150	148.72
(10)	151-300kVa, 3ph	$0.76	300	228.64
(11)	301-500kVa, 3ph	$0.66	500	328.92
(12)	501-1000 kVa, 3ph	$0.61	1,000	612.44
	Very Large Commercial (Secondary)			
(13)	1001-1500kVa, 3ph	$0.57	1,500	859.48
(14)	1501-2000kVa, 3ph	$0.55	2,000	1,107.27
	Very Large Commercial (Primary)			
(15)	3000kVa	$0.48	3,000	1,449.95
(16)	5000kVa	$0.47	5,000	2,325.56
	Lighting			$/Fixture
(17)	Area Light, underground			10.36
(18)	Area Light, overhead			9.42
(19)	Street Light, underground			5.96
(20)	Street Light, overhead			5.02

Table 14 summarizes the monthly marginal customer cost by customer class.

Table 14. Summary of Monthly Marginal Customer Costs

		Monthly Marginal Customer Cost per Customer (2018$ /mo.)
	Residential	
9.01	Residential	15.21
9.02	Residential Controlled Demand	20.13
14.01	Residential Water Heating Control Rider	5.55
14.04	Residential Controlled Service - Large Dual Fuel Rider	17.64
14.05	Residential Controlled Service - Small Dual Fuel Rider	4.13
14.06	Residential Controlled Service - Deferred Load Rider	6.34
14.07	Residential Fixed Time of Service Rider	4.03
11.03, 11.04	Residential Outdoor/Area Lighting	0.30
	Commercial and Industrial	
9.03	Farm Service	17.37
10.01	General Service < 20 kW	24.86
10.02	General Service >= 20 kW	31.84
10.04	Large Commercial Service - Secondary	215.75
	Large Commercial Service - Primary	281.15
10.05	Large General Service - Time of Day (Secondary)	215.75
	Large General Service - Time of Day (Primary)	281.15
14.01	Commercial Water Heating Control Rider	5.55
14.02	Large GS - Real Time Pricing Rider (Secondary)	216.66
	Large GS - Real Time Pricing Rider (Primary)	281.15
14.04	Commercial Controlled Service - Large Dual Fuel Rider	20.06
14.05	Commercial Controlled Service - Small Dual Fuel Rider	7.94
14.06	Commercial Controlled Service - Deferred Load	8.80
14.07	Commercial Fixed Time of Service Rider	6.65
11.02	Irrigation	24.21
10.03	General Service - Time of Use	218.88
11.03, 11.04	Commercial Outdoor/Area Lighting	0.30
	Miscellaneous	
11.03, 11.04	Street Lighting	0.30
11.05, 11.06	Other Public Authority	26.55

Table 15. Summary of Monthly Marginal Customer Cost for Small Power Producers by Rate Class

		Monthly Incremental Customer Cost (2018$/cust/mo.)
	Residential Small Power Producer	
(1)	Residential	0.82
(2)	Residential Demand Control	0.77
	Commercial and Industrial Small Power Producer	
(3)	General Service <20 kW	1.04
(4)	General Service >= 20 kW	1.04
(5)	Farm Service	0.84
(6)	General Service - Time of Use	1.09
(7)	Large General Service (Secondary)	1.16
(8)	Large General Service (Primary)	1.18
(9)	Large General Service - Time of Day (Secondary)	1.16
(10)	Large General Service - Time of Day (Primary)	1.18
(11)	Irrigation Service	1.16

APPENDIX 1: MARGINAL CAPACITY COSTS MODIFIED FOR GRADUALISM IN RATE DESIGN

To recognize the need for gradualism in reforming OTP's marginal cost-based seasonal rates, OTP required an alternative capacity cost allocation scenario that would assign 60% of the annual generation capacity cost to the summer and 40% of the annual cost to the winter season. The resulting cost estimates under this hypothetical split of the marginal generation capacity cost, averaged for years 2018 through 2022 and stated in 2018$, are shown in Table A.1.1. Marginal capacity costs, stated on a per kW basis, are shown in Table A.1.2.

Table A.1.1. Average 2018 – 2022 Marginal Time-Differentiated Costs per kWh using a 60/40 generation capacity cost split

	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
Average 2018-2022	(2018 Cents per kWh)					
(1) **Secondary**						
Energy	3.8440	2.9034	1.8922	3.3569	2.9806	2.0584
Generation Capacity	8.8862	1.1456	0.0185	1.4526	1.1448	0.0114
Regulation and Op. Reserves	0.0880	0.0880	0.0880	0.0880	0.0880	0.0880
Transmission	3.6466	0.3456	0.0057	4.6438	0.4782	0.0838
Distribution Substation	4.1771	0.1404	0.0008	0.0000	0.0000	0.0000
Total	20.6420	4.6230	2.0053	9.5413	4.6917	2.2416
Seasonal	6.0656			4.1023		
Annual	4.7585					
(2) **Primary**						
Energy	3.7012	2.8046	1.8368	3.2132	2.8633	1.9841
Generation Capacity	8.5060	1.0967	0.0178	1.3904	1.0959	0.0109
Regulation and Op. Reserves	0.0860	0.0860	0.0860	0.0860	0.0860	0.0860
Transmission	3.4922	0.3309	0.0044	4.4032	0.4520	0.0789
Distribution Substation	4.0621	0.1366	0.0008	0.0000	0.0000	0.0000
Total	19.8474	4.4548	1.9457	9.0928	4.4972	2.1600
Seasonal	5.8444			3.9313		
Annual	4.5708					
(3) **Transmission**						
Energy	3.4734	2.6457	1.7465	2.9880	2.6778	1.8658
Generation Capacity	7.9080	1.0199	0.0165	1.2927	1.0189	0.0102
Regulation and Op. Reserves	0.0825	0.0825	0.0825	0.0825	0.0825	0.0825
Transmission	2.6406	0.2589	0.0137	3.2767	0.3433	0.0676
Distribution Substation	0.7728	0.0732	0.0012	0.9597	0.0980	0.0170
Total	14.8773	4.0801	1.8604	8.5996	4.2205	2.0431
Seasonal	4.8059			3.7050		
Annual	4.0729					

Table A.1.2. Average 2018 – 2022 Marginal Time-Differentiated Costs per kW using a 60/40 generation capacity cost split

Average 2018-2022	Summer Season			Winter Season		
	Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak
	(1)	(2)	(3)	(4)	(5)	(6)
(1) **Secondary**						
Monthly Costs per Kilowatt (2018 Dollars per Kilowatt)						
Generation Capacity	$11.616	$2.346	$0.074	$1.261	$3.378	$0.040
Transmission	$4.767	$0.708	$0.023	$4.030	$1.411	$0.291
Distribution Substation	$5.460	$0.288	$0.003	$0.000	$0.000	$0.000
Total	$21.84	$3.34	$0.10	$5.29	$4.79	$0.33
Seasonal	$25.28			$10.41		
Annual	$15.37					
(2) **Primary**						
Monthly Costs per Kilowatt (2018 Dollars per Kilowatt)						
Generation Capacity	$11.118	$2.246	$0.070	$1.207	$3.234	$0.038
Transmission	$4.565	$0.678	$0.018	$3.821	$1.334	$0.274
Distribution Substation	$5.310	$0.280	$0.003	$0.000	$0.000	$0.000
Total	$20.99	$3.20	$0.09	$5.03	$4.57	$0.31
Seasonal	$24.29			$9.91		
Annual	$14.70					
(3) **Transmission**						
Monthly Costs per Kilowatt (2018 Dollars per Kilowatt)						
Generation Capacity	$10.337	$2.089	$0.065	$1.122	$3.007	$0.035
Transmission	$3.452	$0.530	$0.054	$2.844	$1.013	$0.235
Distribution Substation						
Total	$13.79	$2.62	$0.12	$3.97	$4.02	$0.27
Seasonal	$16.53			$8.26		
Annual	$11.01					

APPENDIX 2: ANNUALIZATION OF MARGINAL COSTS

Table A.2.1. Annualized Distribution Substation Costs

		2018 Dollars per kW
(1)	Marginal Investment per kW	$244.10
(2)	With General Plant Loading (1) x 1.0130	247.27
(3)	Annual Economic Carrying Charge Related to Capital Investment	7.47%
(4)	A&G Loading (plant related)	0.17%
(5)	Total Annual Carrying Charge (3) + (4)	7.64%
(6)	Annualized Costs (2) x (5)	18.89
(7)	O&M Expenses	1.54
(8)	With A&G (7) x 1.1323 (Non-plant Related)	1.75
(9)	Subtotal (6) + (8)	20.64
	Working Capital	
(10)	Material and Supplies (2) x 1.03%	2.55
(11)	Prepayments (2) x 0.03%	0.07
(12)	Cash Working Capital Allowance (8) x 6.67%	0.12
(13)	Total Working Capital (10) + (11) + (12)	2.74
(14)	Revenue Requirement for Working Capital (13) x 10.61%	0.29
(15)	Total Distribution Substation Costs (9) + (14)	$20.93

Table A.2.2 Annualized Distribution Facilities Costs

		Residential				
		Single Family Urban	Single Family Rural	Apartment Gas	Apartment Electric	Farm
		(2018 Dollars per kW)				
(1)	Marginal Investment per kW	$174.73	$396.62	$144.46	$82.17	$402.18
(2)	With General Plant Loading (1) x 1.0130	177.00	401.78	146.34	83.24	407.41
(3)	Annual Economic Carrying Charge Related to Capital Investment	6.37%	6.37%	6.37%	6.37%	6.37%
(4)	A&G Loading (plant-related)	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Annual Carrying Charge (3) + (4)	6.46%	6.46%	6.46%	6.46%	6.46%
(6)	Annualized Costs (2) x (5)	11.44	25.97	9.46	5.38	26.33
(7)	O&M Expense per kW	4.56	4.56	4.56	4.56	4.56
(8)	With A&G Loading (7) x 1.1323 (non-plant related)	5.16	5.16	5.16	5.16	5.16
(9)	Distribution Facilities Related Costs (6) + (8)	16.60	31.13	14.62	10.54	31.49
	Working Capital					
(10)	Material and Supplies (2) x 1.03%	1.82	4.14	1.51	0.86	4.20
(11)	Prepayments (2) x 0.03%	0.05	0.12	0.04	0.02	0.12
(12)	Cash Working Capital Allowance (8) x 6.67%	0.34	0.34	0.34	0.34	0.34
(13)	Total Working Capital (10) + (11) + (12)	2.22	4.60	1.90	1.23	4.66
(14)	Revenue Requirement for Working Capital (13) x 10.61%	0.24	0.49	0.20	0.13	0.49
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	$16.84	$31.62	$14.82	$10.67	$31.99

Table A.2.3. Annualized Annual Distribution Facilities Costs

		Small Commercial				
		Stand-Alone customer, overhead	Stand-Alone customer 3ph, overhead	Shared-customer 3ph, overhead	Stand-Alone customer, underground	Stand-Alone 3ph, underground
		(2018 Dollars per kW)				
(1)	Marginal Investment per kW	$46.77	$72.34	$82.10	$125.99	163.03
(2)	With General Plant Loading (1) x 1.0130	47.38	73.28	83.17	127.63	165.15
(3)	Annual Economic Carrying Charge Related to Capital Investment	6.37%	6.37%	6.37%	6.37%	6.37%
(4)	A&G Loading (plant-related)	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Annual Carrying Charge (3) + (4)	6.46%	6.46%	6.46%	6.46%	6.46%
(6)	Annualized Costs (2) x (5)	3.06	4.74	5.38	8.25	10.68
(7)	O&M Expense per kW	4.56	4.56	4.56	4.56	4.56
(8)	With A&G Loading (7) x 1.1323 (non-plant related)	5.16	5.16	5.16	5.16	5.16
(9)	Distribution Facilities Related Costs (6) + (8)	8.22	9.90	10.54	13.41	15.84
	Working Capital					
(10)	Material and Supplies (2) x 1.03%	0.49	0.75	0.86	1.31	1.70
(11)	Prepayments (2) x 0.03%	0.01	0.02	0.02	0.04	0.05
(12)	Cash Working Capital Allowance (8) x 6.	0.34	0.34	0.34	0.34	0.34
(13)	Total Working Capital (10) + (11) + (12	0.85	1.12	1.23	1.70	2.09
(14)	Revenue Requirement for Working Capital (13) x 10.61%	0.09	0.12	0.13	0.18	0.22
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	$8.31	$10.02	$10.67	$13.59	$16.06

Table A.2.4. Annualized Distribution Facilities Costs

		Large Commercial (Secondary)				Very Large Commercial (Secondary TOU)		Large Commercial (Primary)	
		101-150kVa, 3ph	151-300kVa, 3ph	301-500kVa, 3ph	501-1000 kVa, 3ph	1001-1500 kVa, 3ph	1501-2000 kVa, 3ph	3000 kVa (LGS), 3ph	5000 kVa (LGS TOU), 3ph
		(2018 Dollars per kW)							
(1)	Marginal Investment per kW	$100.57	$59.26	$40.47	$32.30	$25.19	$21.70	$9.04	$5.76
(2)	With General Plant Loading (1) x 1.0130	101.87	60.03	41.00	32.72	25.51	21.98	9.15	5.83
(3)	Annual Economic Carrying Charge Related to Capital Investment	6.37%	6.37%	6.37%	6.37%	6.37%	6.37%	6.37%	6.37%
(4)	A&G Loading (plant-related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Annual Carrying Charge (3) + (4)	6.46%	6.46%	6.46%	6.46%	6.46%	6.46%	6.46%	6.46%
(6)	Annualized Costs (2) x (5)	6.58	3.88	2.65	2.11	1.65	1.42	0.59	0.38
(7)	O&M Expense per kW	4.56	4.56	4.56	4.56	4.56	4.56	4.56	4.56
(8)	With A&G Loading (7) x 1.1323 (non-plant related)	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16
(9)	Distribution Facilities Related Costs (6) + (8)	11.75	9.04	7.81	7.28	6.81	6.58	5.75	5.54
	Working Capital								
(10)	Material and Supplies (2) x 1.03%	1.05	0.62	0.42	0.34	0.26	0.23	0.09	0.06
(11)	Prepayments (2) x 0.03%	0.03	0.02	0.01	0.01	0.01	0.01	0.00	0.00
(12)	Cash Working Capital Allowance (8) x 6.67%	0.34	0.34	0.34	0.34	0.34	0.34	0.34	0.34
(13)	Total Working Capital (10) + (11) + (12)	1.42	0.98	0.78	0.69	0.61	0.58	0.44	0.41
(14)	Revenue Requirement for Working Capital (13) x 10.61%	0.15	0.10	0.08	0.07	0.07	0.06	0.05	0.04
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	$11.90	$9.15	$7.89	$7.35	$6.88	$6.64	$5.80	$5.58

Table A.2.5. Annualized Lighting Costs

		Lighting			
		Area Light, underground	Area Light, overhead	Street Light, underground	Street Light, overhead
		(2018 Dollars per fixture)			
(1)	Marginal Investment per fixture	$1,415.08	$1,245.71	$622.85	$453.48
(2)	With General Plant Loading (1) x 1.0130	1,433.48	1,261.90	630.95	459.38
(3)	Annual Economic Carrying Charge Related to Capital Investment	6.37%	6.37%	6.37%	6.37%
(4)	A&G Loading (plant-related)	0.10%	0.10%	0.10%	0.10%
(5)	Total Annual Carrying Charge (3) + (4)	6.46%	6.46%	6.46%	6.46%
(6)	Annualized Costs (2) x (5)	92.66	81.57	40.78	29.69
(7)	Lighting O&M Expenses	26.31	26.31	26.31	26.31
(8)	With A&G Loading (7) x 1.1323 (non-plant related)	29.79	29.79	29.79	29.79
(9)	Distribution Facilities Related Costs (6) + (8)	122.44	111.35	70.57	59.48
	Working Capital				
(10)	Material and Supplies (2) x 1.03%	14.76	13.00	6.50	4.73
(11)	Prepayments (2) x 0.03%	0.43	0.38	0.19	0.14
(12)	Cash Working Capital Allowance (8) x 6.67%	1.99	1.99	1.99	1.99
(13)	Total Working Capital (10) + (11) + (12)	17.18	15.36	8.67	6.86
(14)	Revenue Requirement for Working Capital (13) x 10.61%	1.82	1.63	0.92	0.73
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	$124.26	$112.98	$71.49	$60.21

Table A.2.6. Annualized Customer-Related Costs

		Residential	Residential Demand Control	Residential Water Heating Control Rider	Residential Controlled Service - Large Dual Fuel Rider	Residential Controlled Service - Small Dual Fuel Rider	Residential Controlled Service - Deferred Load Rider	Residential Fixed Time of Service Rider
		(2018 Dollars per Customer)						
a) Investment - Meter Costs								
(1)	Meter Cost Investment per Customer	$120.49	$519.81	$415.84	$1,978.59	$423.11	$533.27	$237.91
(2)	With General Plant Loading (1) x 1.0130	122.05	526.56	421.25	2,004.31	428.61	540.20	241.00
(3)	Annual Economic Charge Related to Capital Investment	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%
(4)	A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Carrying Charge Meters (3) + (4)	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%
(6)	Total Annualized Meter Costs (2) x (5)	11.28	48.67	38.93	185.24	39.61	49.93	22.27
b) Investment - Meter Service Drops								
(7)	Service Cost Investment per Customer	$586.71	$586.71	$0.00	$0.00	$0.00	$0.00	$0.00
(8)	With General Plant Loading (1) x 1.0130	594.33	594.33	0.00	0.00	0.00	0.00	0.00
(9)	Annual Economic Charge Related to Capital Investment	6.37%	6.37%	6.37%	6.37%	6.37%	6.37%	6.37%
(10)	A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(11)	Total Carrying Charge Services (9) + (10)	6.46%	6.46%	6.46%	6.46%	6.46%	6.46%	6.46%
(12)	Total Annualized Service Costs (8) x (11)	38.42	38.42	0.00	0.00	0.00	0.00	0.00
c) O&M - Meter, Customer Accounts Expenses, Customer Service								
(13)	Meter and CT O&M Expenses	8.21	10.95	8.21	8.21	8.21	8.21	8.21
(14)	Customer Accounts Expenses	87.43	103.41	15.98	14.72	0.00	14.19	14.19
(15)	Customer Service and Informational Expense	20.95	21.08	0.13	0.58	0.58	0.56	0.56
(16)	With A&G [(13)+(14)+(15)] x 1.1323 (Non-plant Related)	132.01	153.36	27.54	26.62	9.95	26.00	26.00
(17)	Customer-Related Costs (6) + (12) + (16)	181.71	240.44	66.47	211.86	49.57	75.92	48.27
	Working Capital							
(18)	Materials and Supplies (2) x 1.03%	1.26	5.42	4.34	20.64	4.41	5.56	2.48
(19)	Prepayments (2) x 0.030%	0.04	0.16	0.13	0.60	0.13	0.16	0.07
(20)	Cash Working Capital (16) x 6.67%	8.81	10.23	1.84	1.78	0.66	1.73	1.73
(21)	Revenue Requirement for Working Capital [(18)+(19)+(20)] x 10.61%	1.07	1.68	0.67	2.44	0.55	0.79	0.46
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$182.78	$242.12	$67.14	$214.31	$50.12	$76.72	$48.73

Table A.2.7. Annualized Customer-Related Costs

		General Service < 20 kW	General Service >= 20 kW	Farm Service	Large Commercial Secondary	Large Commercial Primary	General Service - Time of Use
		(2018 Dollars per Customer)					
a) Investment - Meter Costs							
(1)	Meter Cost Investment per Customer	$705.79	$705.79	$423.88	$1,744.38	$9,549.89	$1,568.68
(2)	With General Plant Loading (1) x 1.0130	714.96	714.96	429.39	1,767.06	9,674.04	1,589.07
(3)	Annual Economic Charge Related to Capital Investment	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%
(4)	A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Carrying Charge Meters (3) + (4)	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%
(6)	Total Annualized Meter Costs (2) x (5)	66.08	66.08	39.69	163.32	894.10	146.87
b) Investment - Meter Service Drops							
(7)	Service Cost Investment per Customer	$879.73	$1,716.37	$621.57	$27,581.04	$28,403.08	$28,403.08
(8)	With General Plant Loading (1) x 1.0130	891.17	1,738.68	629.65	27,939.60	28,772.32	28,772.32
(9)	Annual Economic Charge Related to Capital Investment	6.37%	6.37%	6.37%	6.37%	6.37%	6.37%
(10)	A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(11)	Total Carrying Charge Services (9) + (10)	6.46%	6.46%	6.46%	6.46%	6.46%	6.46%
(12)	Total Annualized Service Costs (8) x (11)	57.60	112.38	40.70	1,805.92	1,859.75	1,859.75
c) O&M - Meter, Customer Accounts Expenses, Customer Service							
(13)	Meter and CT O&M Expenses	8.21	33.60	10.95	403.24	403.24	403.24
(14)	Customer Accounts Expenses	124.26	124.26	82.60	38.37	38.37	38.37
(15)	Customer Service and Informational Expenses	20.77	20.77	18.82	102.27	102.27	102.27
(16)	With A&G Loading [(13)+(14)+(15)] x 1.1323 (Non-plant Related)	173.51	202.26	127.24	615.83	615.83	615.83
(17)	Customer-Related Costs (6) + (12) + (16)	297.19	380.72	207.62	2,585.07	3,369.68	2,622.44
	Working Capital						
(18)	Materials and Supplies (2) x 1.03%	7.36	7.36	4.42	18.20	99.64	16.37
(19)	Prepayments (2) x 0.030%	0.21	0.21	0.13	0.53	2.90	0.48
(20)	Cash Working Capital (16) x 6.67%	11.57	13.49	8.49	41.08	41.08	41.08
(21)	Revenue Requirement for Working Capital [(18)+(19)+(20)] x 10.61%	2.03	2.24	1.38	6.35	15.24	6.15
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$299.23	$382.96	$209.00	$2,591.41	$3,384.92	$2,628.59

Table A.2.8. Annualized Customer-Related Costs

		Large GS (Real Time Pricing) Secondary	Large GS (Real Time Pricing) Primary	Large GS - TOD Secondary	Large GS - TOD Primary
		(2018 Dollars per Customer)			
a) Investment - Meter Costs					
(1)	Meter Cost Investment per Customer	$1,834.37	$9,549.89	$1,744.38	$9,549.89
(2)	With General Plant Loading (1) x 1.0130	1,858.22	9,674.04	1,767.06	9,674.04
(3)	Annual Economic Charge Related to Capital Investment	9.14%	9.14%	9.14%	9.14%
(4)	A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%
(5)	Total Carrying Charge Meters (3) + (4)	9.24%	9.24%	9.24%	9.24%
(6)	Total Annualized Meter Costs (2) x (5)	171.74	894.10	163.32	894.10
b) Investment - Meter Service Drops					
(7)	Service Cost Investment per Customer	$27,581.04	$28,403.08	$27,581.04	$28,403.08
(8)	With General Plant Loading (1) x 1.0130	27,939.60	28,772.32	27,939.60	28,772.32
(9)	Annual Economic Charge Related to Capital Investment	6.37%	6.37%	6.37%	6.37%
(10)	A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%
(11)	Total Carrying Charge Services (9) + (10)	6.46%	6.46%	6.46%	6.46%
(12)	Total Annualized Service Costs (8) x (11)	1,805.92	1,859.75	1,805.92	1,859.75
c) O&M - Meter, Customer Accounts Expenses, Customer Service					
(13)	Meter and CT O&M Expenses	403.24	403.24	403.24	403.24
(14)	Customer Accounts Expenses	38.37	38.37	38.37	38.37
(15)	Customer Service and Informational Expenses	102.27	102.27	102.27	102.27
(16)	With A&G Loading [(13)+(14)+(15)] x 1.132 (Non-plant Related)	615.83	615.83	615.83	615.83
(17)	Customer-Related Costs (6) + (12) + (16)	2,593.49	3,369.68	2,585.07	3,369.68
	Working Capital				
(18)	Materials and Supplies (2) x 1.03%	19.14	99.64	18.20	99.64
(19)	Prepayments (2) x 0.030%	0.56	2.90	0.53	2.90
(20)	Cash Working Capital (16) x 6.67%	41.08	41.08	41.08	41.08
(21)	Revenue Requirement for Working Capital [(18)+(19)+(20)] x 10.61%	6.45	15.24	6.35	15.24
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$2,599.94	$3,384.92	$2,591.41	$3,384.92

Table A.2.9. Annualized Customer-Related Costs

		Commercial Water Heating Control	Commercial Controlled Service - Large Dual Fuel (14.04)	Commercial Controlled Service - Small Dual Fuel (14.05)	Commercial Controlled Service - Deferred Load (14.06)	Small Commercial Fixed Time of Service (14.07)
		(2018 Dollars per Customer)				
a) Investment - Meter Costs						
(1)	Meter Cost Investment per Customer	$415.84	$1,978.59	$423.11	$533.27	$533.27
(2)	With General Plant Loading (1) x 1.0130	421.25	2,004.31	428.61	540.20	540.20
(3)	Annual Economic Charge Related to Capital Investment	9.14%	9.14%	9.14%	9.14%	9.14%
(4)	A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Carrying Charge Meters (3) + (4)	9.24%	9.24%	9.24%	9.24%	9.24%
(6)	Total Annualized Meter Costs (2) x (5)	38.93	185.24	39.61	49.93	49.93
c) O&M - Meter, Customer Accounts Expenses, Customer Service						
(7)	Meter and CT O&M Expenses	8.21	33.60	33.60	33.60	10.95
(8)	Customer Accounts Expenses	15.98	14.72	14.72	14.72	14.72
(9)	Customer Service and Informational Expenses	0.13	0.58	0.58	0.58	0.58
(10)	With A&G Loading [(7)+(8)+(9)] x 1.1323 (Non-plant Related)	27.54	55.37	55.37	55.37	29.72
(11)	Customer-Related Costs (6) + (10)	66.47	240.61	94.98	105.30	79.65
	Working Capital					
(12)	Materials and Supplies (2) x 1.03%	4.34	20.64	4.41	5.56	5.56
(13)	Prepayments (2) x 0.030%	0.13	0.60	0.13	0.16	0.16
(14)	Cash Working Capital (16) x 6.67%	1.84	3.69	3.69	3.69	1.98
(15)	Revenue Requirement for Working Capital [(12)+(13)+(14)] x 10.61%	0.67	2.65	0.87	1.00	0.82
(16)	Total Annual Marginal Customer-Related Costs (11) + (15)	$67.14	$243.26	$95.86	$106.30	$80.47

Table A.2.10. Annualized Customer-Related Costs

		Irrigation (11.02)	Other Public Authority
a) Investment - Meter Costs			
(1)	Meter Cost Investment per Customer	$1,245.54	$437.73
(2)	With General Plant Loading (1) x 1.0130	1,261.73	443.42
(3)	Annual Economic Charge Related to Capital Investment	9.14%	9.14%
(4)	A&G Loading (Plant Related)	0.10%	0.10%
(5)	Total Carrying Charge Meters (3) + (4)	9.24%	9.24%
(6)	Total Annualized Meter Costs (2) x (5)	116.61	40.98
b) Investment - Meter Service Drops			
(7)	Service Cost Investment per Customer	$586.71	$1,716.37
(8)	With General Plant Loading (1) x 1.0130	594.33	1,738.68
(9)	Annual Economic Charge Related to Capital Investment	6.37%	6.37%
(10)	A&G Loading (Plant Related)	0.10%	0.10%
(11)	Total Carrying Charge Services (9) + (10)	6.46%	6.46%
(12)	Total Annualized Service Costs (8) x (11)	38.42	112.38
c) O&M - Meter, Customer Accounts Expenses, Customer Service			
(13)	Meter and CT O&M Expenses	25.20	33.60
(14)	Customer Accounts Expenses	83.16	91.97
(15)	Customer Service and Informational Expenses	10.53	18.95
(16)	With A&G Loading [(13)+(14)+(15)] x 1.1323 (Non-plant Related)	134.62	163.64
(17)	Customer-Related Costs (6) + (12) + (16)	289.65	317.00
	Working Capital		
(18)	Materials and Supplies (2) x 1.03%	13.00	4.57
(19)	Prepayments (2) x 0.030%	0.38	0.13
(20)	Cash Working Capital (16) x 6.67%	8.98	10.91
(21)	Revenue Requirement for Working Capital [(18)+(19)+(20)] x 10.61%	2.37	1.66
(22)	Total Annual Marginal Customer-Related Costs (11) + (15)	$292.02	$318.66

Table A.2.11. One-Time Expense per Interconnection of Small Power Producer

	Small Power Producer Rider	Interconnection Labor Cost (2018$)
(1)	Average Annual Salary of Technical & Admin Personnel Involved	$96,516.21
(2)	Annual hours net of paid vacation & holiday	1,880.00
(3)	Hourly average labor cost	$48.39
(4)	Hours required per interconnection	$20.00
(5)	Expense per Interconnection Request	$967.83
(6)	With Non-Plant Related A&G (5) x 1.1323	$1,095.86
(7)	Working Capital	
(8)	Cash Working Capital (6) x 6.67%	$73.09
(9)	Revenue Requirement for Working Capital	
(10)	(8) x 11.20%	$7.76
(11)	Total One-time Incremental Cost to Process and Energize Interconnection (6) + (10)	$1,103.62

Table A.2.12. Incremental Annualized Cost of Meter for Small Power Producers by Rate Class

		Residential	Residential Demand Control	General Service < 20 kW	General Service >= 20 kW	Farm Service	General Service - Time of Use	Large Comm. Secondary	Large Comm. Primary	Large GS - TOD Secondary	Large GS - TOD Primary	Irrigation (11.02)
				(2018 Dollars per Customer)								
Incremental Bi-directional Meter Costs for Small PP												
(1)	Meter Cost Investment per Customer	$103.96	$99.24	$134.44	$134.44	107.49	141.82	150.97	156.25	150.97	156.25	149.90
(2)	With General Plant Loading (1) x 1.0130	105.31	100.53	136.19	136.19	108.89	143.67	152.93	158.28	152.93	158.28	151.85
(3)	Annual Economic Charge Related to Capital Investment	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%	9.14%
(4)	A&G Loading (Plant Related)	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Carrying Charge Meters (3) + (4)	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%	9.24%
(6)	Total Annualized Meter Costs (2) x (5)	9.73	9.29	12.59	12.59	10.06	13.28	14.13	14.63	14.13	14.63	14.03
(7)	Working Capital											
(8)	Materials and Supplies (2) x 1.03%	1.08	1.04	1.40	1.40	1.12	1.48	1.58	1.63	1.58	1.63	1.56
(9)	Prepayments (2) x 0.030%	0.03	0.03	0.04	0.04	0.03	0.04	0.05	0.05	0.05	0.05	0.05
(10)	Revenue Requirement for Working Capital [(8)+(9)] x 10.61%	0.12	0.11	0.15	0.15	0.12	0.16	0.17	0.18	0.17	0.18	0.17
(11)	Total Annual Incremental Bi-Directional Meter Costs (6) + (10)	$9.85	$9.40	$12.74	$12.74	$10.19	$13.44	$14.31	$14.81	$14.31	$14.81	$14.21

Proposed Test Year 2018 Operating Revenue Summary Comparison - By Rate Schedule

Line No.	Rate Schedule	Operating Revenues Present	Operating Revenues Proposed	Difference	Percent Change
1	9.01 Residential Service (Rate 101)	$ 41,898,051	$ 47,011,619	$ 5,113,568	12.20%
2	9.02 Residential Demand Control (Rate 241)	$ 6,311,866	$ 7,803,055	$ 1,491,189	23.63%
3	Total Residential:	$ 48,209,916	$ 54,814,675	$ 6,604,759	13.70%
4					
5	9.03 Farm Service (Rate 361)	$ 2,612,687	$ 2,970,625	$ 357,938	13.70%
6	Total Farm:	$ 2,612,687	$ 2,970,625	$ 357,938	13.70%
7					
8	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)	$ 9,525,909	$ 10,315,886	$ 789,977	8.29%
9	10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)	$ 532	$ 580	$ 48	8.96%
10	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)	$ 29,345,494	$ 31,774,386	$ 2,428,892	8.28%
11	10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)	$ 69,010	$ 70,401	$ 1,391	2.02%
12	10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)	$ 9,671	$ 11,268	$ 1,597	16.52%
13	Total General Service:	$ 38,950,615	$ 42,172,520	$ 3,221,905	8.27%
14					
15	10.04 Large General Service - Secondary Service (Rate 603)	$ 31,657,902	$ 33,821,005	$ 2,163,104	6.83%
16	10.04 Large General Service - Primary Service (Rate 602) with RTP Rider (Rate 662)	$ 11,449,285	$ 12,844,033	$ 1,394,749	12.18%
17	10.04 Large General Service - Transmission Service (Rate 632)	$ -	$ -	$ -	0.00%
18	10.05 Large General Service Time of Day - Secondary Service (Rates 611, 615, 613)	$ 38,758	$ 43,947	$ 5,189	13.39%
19	10.05 Large General Service Time of Day - Primary Service (Rates 610, 614, 612)	$ -	$ -	$ -	0.00%
20	10.05 Large General Service Time of Day - Transmission Service (Rates 639, 637, 640)	$ -	$ -	$ -	0.00%
21	11.01 Stanby Service Rider	$ 14,765	$ 16,799	$ 2,034	13.78%
22	Total Large General Service:	$ 43,160,710	$ 46,725,785	$ 3,565,075	8.26%
23					
24	11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)	$ 27,950	$ 31,103	$ 3,153	11.28%
25	11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)	$ 31,131	$ 39,203	$ 8,073	25.93%
26	Total Irrigation:	$ 59,081	$ 70,307	$ 11,226	19.00%
27					
28	11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)	$ 97,912	$ 119,790	$ 21,878	22.34%
29	11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)	$ 248,383	$ 320,152	$ 71,769	28.89%
30	11.03 Outdoor Lighting - Signal (Rate 744)	$ 37,481	$ 47,143	$ 9,662	25.78%
31	11.04 Outdoor Lighting - Street & Area Lighting (Rate 741)	$ 1,900,540	$ 2,103,818	$ 203,278	10.70%
32	11.04 Outdoor Lighting - Flood Lighting (Rate 743)	$ 584,826	$ 651,228	$ 66,402	11.35%
33	Total Lighting:	$ 2,869,142	$ 3,242,131	$ 372,989	13.00%
34					
35	11.05 Municipal Pumping - Secondary Service (Rate 872)	$ 1,200,018	$ 1,357,078	$ 157,060	13.09%
36	11.06 Civil Defense - Fire Sirens (Rate 843)	$ 3,969	$ 3,426	$ (542)	-13.66%
37	Total Other Public Authority:	$ 1,203,986	$ 1,360,505	$ 156,519	13.00%
38					
39	14.01 Water Heating - Controlled Service (Rate 191)	$ 1,085,033	$ 1,233,682	$ 148,650	13.70%
40	Total Water Heating:	$ 1,085,033	$ 1,233,682	$ 148,650	13.70%
41					
42	14.04 Controlled Service - Interruptible Load Rider CT Metering (Rates 170, 165, 881, 168, 268, 169, 269)	$ 2,480,828	$ 2,974,204	$ 493,377	11.83%
43	14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)	$ 5,916,326	$ 6,573,361	$ 657,034	11.11%
44	Total Interruptible:	$ 8,397,155	$ 9,547,565	$ 1,150,411	13.70%
45					
46	14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)	$ 1,036,142	$ 1,064,957	$ 28,815	2.78%
47	14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)	$ 281,954	$ 336,896	$ 54,942	19.49%
48	14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)	$ 205,527	$ 247,622	$ 42,094	20.48%
49	Total Deferred Load:	$ 1,523,624	$ 1,649,475	$ 125,851	8.26%
50					
51	TOTAL REVENUE:	$ 148,071,950	$ 163,787,270	$ 15,715,320	10.61%
52					

CCOSS or EPMC Method	Rate Classes	Proposed Intra-Class Increase	Total Present Revenues (including Riders)	Total Proposed Revenues (including Riders)	Change in Non-Fuel Base Revenues	Present Base Rate Revenue 2018 (excluding Riders)	Proposed Base Rate Revenue (excluding Riders)	2018 Average Revenue 100% Marginal Cost	2018 Proposed Revenue as % of 100% MC	Marginal Revenue Allocation
Method 2	Residential Service	12.20%	$ 41,898,051	$ 47,011,619	-1.56%	$ 36,601,009	$ 36,030,409	$ 35,298,607	102.1%	84.9%
	Res. Demand Control	23.63%	$ 6,311,866	$ 7,803,055	3.49%	$ 5,364,879	$ 5,552,254	$ 6,271,651	88.5%	15.1%
	RESIDENTIAL CLASS	**13.70%**	**$ 48,209,916**	**$ 54,814,675**	**-0.91%**	**$ 41,965,888**	**$ 41,582,663**	**$ 41,570,258**	**100.0%**	**100.0%**
CCOSS	**Farm Service**	**13.70%**	**$ 2,612,687**	**$ 2,970,625**	**-2.08%**	**$ 2,155,303**	**$ 2,110,506**	**$ 2,324,518**	**90.8%**	
Method 2	Small General Service	8.29%	$ 9,526,441	$ 10,316,466	-4.67%	$ 8,376,479	$ 7,985,135	$ 6,809,680	117.3%	27.7%
	General Service	8.26%	$ 29,414,504	$ 31,844,787	-8.25%	$ 25,575,200	$ 23,464,413	$ 17,754,659	132.2%	72.3%
	GS Time of Use	16.52%	$ 9,671	$ 11,268	-1.75%	$ 8,328	$ 8,182	$ 7,807	104.8%	0.032%
	GENERAL SERVICE CLASS	**8.27%**	**$ 38,950,615**	**$ 42,172,520**	**-7.37%**	**$ 33,960,007**	**$ 31,457,729**	**$ 24,572,147**	**128.0%**	**100.0%**
Method 1	**LGS CLASS**	**8.26%**	**$ 43,160,710**	**$ 46,725,785**	**-17.00%**	**$ 37,389,529**	**$ 31,031,481**	**$ 36,590,771**	**84.8%**	**100.0%**
	LGS Secondary	6.83%	$ 31,657,902	$ 33,821,005	-17.24%	$ 27,517,756	$ 22,773,982	$ 27,358,886	83.2%	74.8%
	LGS Primary & RTP Rider	12.18%	$ 11,449,285	$ 12,844,033	-16.41%	$ 9,824,615	$ 8,212,272	$ 9,195,390	89.3%	25.1%
	LGS Transmission	n/a	$ -	$ -	n/a	$ -	$ -	$ -	0.0%	0.0%
	LGS Subtotal	8.25%	$ 43,107,186	$ 46,665,039	-17.02%	$ 37,342,371	$ 30,986,254	$ 36,554,276	84.8%	99.90%
	LGS TOD Secondary	13.39%	$ 38,758	$ 43,947	-5.68%	$ 34,024	$ 32,093	$ 36,495	87.9%	0.1%
	LGS TOD Primary	n/a	$ -	$ -	n/a	$ -	$ -	$ -	0.0%	0.0%
	LGS TOD Transmission	n/a	$ -	$ -	n/a	$ -	$ -	$ -	0.0%	0.0%
	Standby Service	13.78%	$ 14,765	$ 16,799	0.00%	$ 13,134	$ 13,134	$ -	0%	0%
	LGS TOD Subtotal	13.5%	$ 53,523	$ 60,746	-4.1%	$ 47,158	$ 45,227	$ 36,495	123.9%	0.10%
Method 1	Irrigation	11.28%	$ 27,950	$ 31,103	-9.43%	$ 26,344	$ 23,859	$ 25,462	93.7%	47.1%
	Irrigation Time of Use	25.93%	$ 31,131	$ 39,203	-9.19%	$ 29,401	$ 26,698	$ 28,569	93.5%	52.9%
	IRRIGATION CLASS	**19.0%**	**$ 59,081**	**$ 70,307**	**-9.3%**	**$ 55,745**	**$ 50,557**	**$ 54,031**	**93.6%**	**100.00%**
Method 3	Lighting Energy Only	26.92%	$ 383,776	$ 487,085	5.28%	$ 339,322	$ 357,222	$ 148,674	240.3%	21.6%
	Area Lighting	10.85%	$ 2,485,366	$ 2,755,046	1.43%	$ 2,258,606	$ 2,290,951	$ 540,068	424.2%	78.4%
	OUTDOOR LIGHTING CLASS	**13.00%**	**$ 2,869,143**	**$ 3,242,131**	**1.93%**	**$ 2,597,928**	**$ 2,648,173**	**$ 688,742**	**384.5%**	**100.00%**
CCOSS	Municipal Pumping	13.09%	$ 1,200,018	$ 1,357,078	-10.73%	$ 1,039,969	$ 928,426	$ 978,639	94.9%	99.8%
	Fire Sirens	-13.66%	$ 3,969	$ 3,426	-8.06%	$ 3,727	$ 3,426	$ 2,423	141.4%	0.2%
	OPA CLASS	**13.00%**	**$ 1,203,986**	**$ 1,360,504**	**-10.72%**	**$ 1,043,696**	**$ 931,853**	**$ 981,062**	**95.0%**	**100.00%**
CCOSS	**Water Heating**	**13.70%**	**$ 1,085,033**	**$ 1,233,682**	**-13.09%**	**$ 987,779**	**$ 858,515**	**$ 1,319,964**	**65.0%**	**100.0%**
Method 1	Large Dual Fuel	19.89%	$ 2,480,828	$ 2,974,204	-40.80%	$ 2,130,188	$ 1,261,089	$ 2,819,159	44.7%	27.1%
	Small Dual Fuel	11.11%	$ 5,916,326	$ 6,573,361	-37.59%	$ 5,165,773	$ 3,223,769	$ 7,600,519	42.4%	72.9%
	CONTROLLED SERVICE INTERRUPTIBLE	**11.5%**	**$ 8,397,155**	**$ 9,547,565**	**11.5%**	**$ 7,295,962**	**$ 4,484,858**	**$ 10,419,677**	**43.0%**	**100.00%**
Method 1	Deferred Load	2.78%	$ 1,036,142.38	$ 1,064,957.03	-32.02%	$ 918,394	$ 624,307	$ 806,358	77.4%	71.5%
	Fixed Time of Service	19.91%	$ 487,482	$ 584,518	-34.07%	$ 242,868	$ 160,130	$ 321,682	49.8%	28.5%
	CONTROLLED SERVICE DEFERRED	**8.26%**	**$ 1,523,624**	**$ 1,649,475**	**-32.83%**	**$ 1,337,726**	**$ 898,580**	**$ 1,128,041**	**79.7%**	**100.00%**
	Total	**10.61%**	**$ 148,071,950**	**$ 163,787,269**	**-9.89%**	**$ 128,789,562**	**$ 116,054,915**	**$ 82,406,193**	**140.8%**	

Class	Present Customer Charge ($/Month)	Proposed Customer Charge ($/Month)	2008 Marginal Cost ($/Month)	2018 Marginal Cost ($/Month)	Present Customer Charge as Percent of 2008 Marginal Cost	Proposed Customer Charge as Percent of 2018 Marginal Cost
Residential	$8.00	$17.70	$10.11	$17.70	79%	100.0%
Residential – Demand Control	$18.38	$20.10	$16.77	$20.18	110%	99.6%
Farm Service – Single Phase	$12.00	$17.40	$12.34	$17.42	97%	99.9%
Farm Service – Three Phase	$12.00	$17.40	$12.34	$17.42	97%	99.9%
Small General Service	$13.00	$24.90	$17.51	$24.94	74%	99.8%
General Service (Secondary)	$12.00	$31.90	$26.50	$31.91	45%	100.0%
General Service TOU	$16.00	$219.00	$259.06	$219.05	6%	100.0%
Large General Service (Secondary)	$40.00	$215.90	$254.44	$215.95	16%	100.0%
Large General Service – Time of Day (Primary)	$60.00	$282.00	$303.69	$282.08	20%	100.0%
Irrigation – Option 1	$1.00	$24.30	$23.56	$24.33	4%	99.9%
Irrigation – Option 2	$5.00	$24.30	$259.06	$24.33	2%	99.9%
Outdoor Lighting – Metered	$2.00	$2.00	$4.26	$0.30	47%	667%
Outdoor Lighting – Non-metered	$0.00	$0.00	$3.67	$0.30	0%	0.0%
Municipal Pumping (All)	$4.00	$26.50	$25.21	$26.55	16%	99.8%
Civil Defense	$1.00	$1.22	$25.21	$26.55	4%	4.6%
Water Heating	$1.00	$4.00	$6.70	$5.59	15%	71.6%
Controlled Service - Interruptible- Large #1	$4.00	$20.20	$34.17	$20.27	12%	99.7%
Controlled Service - Interruptible- Large #2	$5.00	$20.20	$34.17	$20.27	15%	99.7%
Controlled Service – Interruptible-Small	$2.00	$8.50	$14.35	$20.27	14%	41.9%
Deferred Load Service	$3.00	$8.80	$17.23	$8.86	17%	99.3%
Fixed Time of Service	$1.50	$6.70	$17.23	$6.71	9%	99.9%

Residential Service (Section 9.01) Usage Analysis
(2016 Actual Data - ND)

	All	Low-Income[1]	Non- Low Income
Total number of residential customers on the standard residential tariff	37,593	1,068	36,525
Total number of residential customers using less than 750 kwh	22,352	451	21,901
Total number of residential customers using 750 kwh or more	15,241	617	14,624
Average monthly usage for residential customers	786	1184	774
Average monthly usage for residential customers using less than 750 kwh	376	435	375
Average monthly usage for residential customers using 750 kwh or more	1,387	1,731	1,372
Average bill for residential customers	$86.10	$122.71	$85.03
Average bill for residential customers using less than 750 kwh	$46.54	$52.61	$46.42
Average bill for residential customers using 750 kwh or more	$144.10	$173.94	$142.84
Total number of residential customers using less than 750 kwh	59%	42%	60%
Total number of residential customers using 750 kwh or more	41%	58%	40%
Average monthly usage for residential customers using less than 750 kwh	48%	37%	48%
Average monthly usage for residential customers using 750 kwh or more	176%	146%	177%
Average bill for residential customers using less than 750 kwh	54%	43%	55%
Average bill for residential customers using 750 kwh or more	167%	142%	168%

Notes
1. Defined as customers in the LIHEAP Program.

ELECTRIC RATE SCHEDULE 10.05
Large General Service - Time of Day

PRESENT
TIME OF DAY PRICE PERIOD DESIGNATIONS

Summer season June, July, Aug, Sept

Hour Ending	Sun	Mon	Tue	Wed	Thu	Fri	Sat
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							

Winter season Oct through May

Hour Ending	Sun	Mon	Tue	Wed	Thu	Fri	Sat
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
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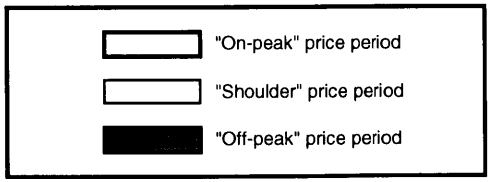
18							
19							
20							
21							
22							
23							
24							



ELECTRIC RATE SCHEDULE 10.05
Large General Service - Time of Day

PROPOSED
TIME OF DAY PRICE PERIOD DESIGNATIONS

Summer season June, July, Aug, Sept

Hour Ending	Sun	Mon	Tue	Wed	Thu	Fri	Sat
1							
2							
3							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							

Winter season Oct through May

Hour Ending	Sun	Mon	Tue	Wed	Thu	Fri	Sat
1							
2							
3							
4							
5							
6							
7							
8							
9							
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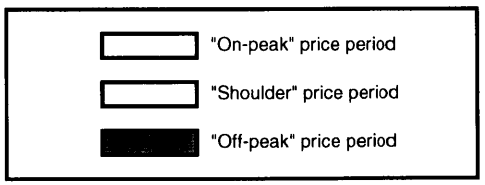

and O&M Related Costs			LED5	LED10	LED3PT	LED5PT	LED8	LED13	LED20 FLOOD	LED30 FLOOD	SEC LIGHT BOTTO
Marginal Investment per fixture (all costs and labor)		Input-Lighting Cost workpapers	$268.37	$399.58	$552.41	$586.58	$317.57	$440.58	$975.83	$1,180.84	$
With General Plant Loading		(1) x 1.0130	$271.86	$404.77	$559.59	$594.21	$321.70	$446.31	$988.52	$1,196.19	$
Annual Economic Carrying Charge Related to Capital Investment	(9)	Input - Marginal Cost Study T29 P5	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	9.49%	
A&G Loading (plant-related)	(10)	Input - Marginal Cost Study T29 P5	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	
Total Annual Carrying Charge		(3) + (4)	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	9.59%	
Annualized Costs		(2) x (5)	$26.06	$38.81	$53.65	$56.97	$30.84	$42.79	$94.77	$114.68	
Annual Lighting O&M Expenses		Input-Lighting Cost workpapers	$11.76	$11.76	$11.76	$11.76	$11.76	$11.76	$11.76	$11.76	
With A&G Loading (non-plant related)		(7) x 1 1323 Input-Marginal Cost Study	$13.32	$13.32	$13.32	$13.32	$13.32	$13.32	$13.32	$13.32	
Distribution Facilities Related Costs		(6) + (8)	$39.38	$52.12	$66.97	$70.28	$44.16	$56.11	$108.09	$128.00	
Working Capital											
Material and Supplies		(2) x 1 20%	$3.26	$4.86	$6.72	$7.13	$3.86	$5.36	$11.86	$14.35	
Prepayments		(2) x 0 03%	$0.08	$0.12	$0.17	$0.18	$0.10	$0.13	$0.30	$0.36	
Cash Working Capital Allowance		(8) x 6 67%	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	$0.89	
Total Working Capital		(10) + (11) + (12)	$4.23	$5.87	$7.77	$8.20	$4.85	$6.38	$13.05	$15.60	
Revenue Requirement for Working Capital		(13) x 11 20%	$0.47	$0.66	$0.87	$0.92	$0.54	$0.71	$1.46	$1.75	
Total Annual Marginal Distribution Facilities Related Costs		(9) + (14)	$39.85	$52.78	$67.84	$71.20	$44.70	$56.82	$109.55	$129.75	
Meter… Accounts Expenses, Customer Service											
…r and CT O&M Expenses	(13)	Input - Marginal Cost Study T29 P5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Customer Accounts Expenses	(14)	Input - Marginal Cost Study T29 P5	$2.39	$2.39	$2.39	$2.39	$2.39	$2.39	$2.39	$2.39	
Customer Service and Informational Expenses	(15)	Input - Marginal Cost Study T29 P5	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	
With A&G Loading (Non-plant Related)		[(16)+(17)+(18)] x 1 1323	$3.95	$3.95	$3.95	$3.95	$3.95	$3.95	$3.95	$3.95	
Customer-Related Costs		(6) + (12) + (16)	$26.95	$39.70	$54.54	$57.86	$31.73	$43.68	$95.66	$115.57	
Working Capital											
Materials and Supplies			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Prepayments			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	
Cash Working Capital		(19) x 6 67%	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26	
Revenue Requirement for Working Capital		[(21)+(22)+(23)]x11 20%	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	
Total Annual Marginal Customer-Related Costs		(20) + (24)	$26.98	$39.73	$54.57	$57.89	$31.76	$43.71	$95.69	$115.60	
Total Annual Marginal Facilites & Customer-Related Costs per fixture		(15) + (25)	$66.84	$92.51	$122.40	$129.09	$76.46	$100.53	$205.24	$245.35	
Monthly Marginal Facilities & Customer-Related Costs per lighting fixture		(26) / 12	$5.57	$7.71	$10.20	$10.76	$6.37	$8.38	$17.10	$20.45	
Costs Calculation per Fixture											
Lighting fixture input (connected kW)		input - Mfg data	0.047	0.095	0.026	0.047	0.076	0.133	0.199	0.261	
Monthly charge per connected l (Marginal KWH rate/4100/12month)	$7.26	input Section 11 03, Rate Code 31-749	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	
Monthly kWh charge		(26 * 27)	$0.34	$0.69	$0.19	$0.34	$0.55	$0.97	$1.44	$1.89	
nthly Fixture Cost											
Monthly Marginal Cost per fixture (excluding monthly energy)		(27)	$5.57	$7.71	$10.20	$10.76	$6.37	$8.38	$17.10	$20.45	
Monthly kWh charge		(28)	$0.34	$0.69	$0.19	$0.34	$0.55	$0.97	$1.44	$1.89	
Total Monthly Pole Cost		(29)	$9.53	$9.53	$8.89	$10.45	$9.53	$11.43	$11.43	$16.00	
Total Monthly Fixture Cost		(27) + (28)+(29)	$15.44	$17.93	$19.28	$21.55	$16.45	$20.77	$29.98	$38.34	

---------- (2016 Dollars per fixture) ----------

				FIBERGLASS STANDARDS FS18	FIBERGLASS STANDARD S FS23	ALUMINUM ALLOY STANDARDS 30'	ALUMINUM ALLOY STANDARDS40'	STANDARD POLE (LED5, LED8 & LED10)	STANDARD POLE (LED13 & LED20 FLOOD)	STANDARD POLE (LED30 FLOOD)	FLOOD LIGHTING VISOR LED 20 FLOOD	FLOOD LIGHTING VISOR LED30 FLOOD
Facilities and O&M Related Costs												
(1)	Marginal Investment per fixture (all costs and labor)		Input-Lighting Cost workpapers	$766.89	$901.15	$2,979.13	$3,237.00	$821.72	$985.76	$1,380.09	$65.23	$118.94
(2)	With General Plant Loading		(1) x 1.0130	$776.86	$912.86	$3,017.86	$3,279.08	$832.40	$998.57	$1,398.03	$66.08	$120.49
(3)	Annual Economic Carrying Charge Related to Capital Investment	(9)	Input - Marginal Cost Study T29 P5	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%	6.70%
(4)	A&G Loading (plant-related)	(10)	Input - Marginal Cost Study T29 P5	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%	0.10%
(5)	Total Annual Carrying Charge		(3) + (4)	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%	6.80%
(6)	Annualized Costs		(2) x (5)	$52.81	$62.05	$205.14	$222.90	$56.58	$67.88	$95.03	$4.49	$8.19
(7)	Annual Lighting O&M Expenses		Input-Lighting Cost workpapers	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(8)	With A&G Loading (non-plant related)		(7) x 1 1323 Input-Marginal Cost Study	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(9)	Distribution Facilities Related Costs		(6) + (8)	$52.81	$62.05	$205.14	$222.90	$56.58	$67.88	$95.03	$4.49	$8.19
	Working Capital											
(10)	Material and Supplies		(2) x 1 20%	$9.32	$10.95	$36.21	$39.35	$9.99	$11.98	$16.78	$0.79	$1.45
(11)	Prepayments		(2) x 0 03%	$0.23	$0.27	$0.91	$0.98	$0.25	$0.30	$0.42	$0.02	$0.04
(12)	Cash Working Capital Allowance		(8) x 6 67%	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(13)	Total Working Capital		(10) + (11) + (12)	$9.56	$11.23	$37.12	$40.33	$10.24	$12.28	$17.20	$0.81	$1.48
(14)	Revenue Requirement for Working Capital		(13) x 11 20%	$1.07	$1.26	$4.16	$4.52	$1.15	$1.38	$1.93	$0.09	$0.17
(15)	Total Annual Marginal Distribution Facilities Related Costs		(9) + (14)	$53.88	$63.31	$209.30	$227.42	$57.73	$69.25	$96.96	$4.58	$8.36
O&M - Meter, Customer Accounts Expenses, Customer Service												
(16)	Meter and CT O&M Expenses	(13)	Input - Marginal Cost Study T29 P5	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(17)	Customer Accounts Expenses	(14)	Input - Marginal Cost Study T29 P5	$2.39	$2.39	$2.39	$2.39	$2.39	$2.39	$2.39	$2.39	$2.39
(18)	Customer Service and Informational Expenses	(15)	Input - Marginal Cost Study T29 P5	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10	$1.10
(19)	With A&G Loading (Non-plant Related)		[(16)+(17)+(18)] x 1 1323	$3.95	$3.95	$3.95	$3.95	$3.95	$3.95	$3.95	$3.95	$3.95
(20)	Customer-Related Costs		(6) + (12) + (16)	$52.81	$62.05	$205.14	$222.90	$56.58	$67.88	$95.03	$4.49	$8.19
	Working Capital											
(21)	Materials and Supplies			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(22)	Prepayments			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(23)	Cash Working Capital		(19) x 6 67%	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26	$0.26
(24)	Revenue Requirement for Working Capital		[(21)+(22)+(23)]x11 20%	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03	$0.03
(25)	Total Annual Marginal Customer-Related Costs		(20) + (24)	$52.84	$62.08	$205.17	$222.93	$56.61	$67.91	$95.06	$4.52	$8.22
(26)	Total Annual Marginal Facilites & Customer-Related Costs per fixture		(15) + (25)	$106.72	$125.39	$414.47	$450.34	$114.34	$137.16	$192.02	$9.10	$16.58
(27)	Monthly Marginal Facilities & Customer-Related Costs per lighting fixture		(26) / 12	$8.89	$10.45	$34.54	$37.53	$9.53	$11.43	$16.00	$0.76	$1.38
Energy Costs Calculation per Fixture												
(26)	Lighting fixture input (connected kW)		input - Mfg data	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(27)	Monthly charge per connected l (Marginal KWH rate/4100/12month)	$7.26	input Section 11 03, Rate Code 31-749	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26	$7.26
(28)	Monthly kWh charge		(26 * 27)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total Monthly Fixture Cost												
(29)	Monthly Marginal Cost per fixture (excluding monthly energy)		(27)	$8.89	$10.45	$34.54	$37.53	$9.53	$11.43	$16.00	$0.76	$1.38
(30)	Monthly kWh charge		(28)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
(30)	Total Monthly Pole Cost		(29)									
(32)	Total Monthly Fixture Cost		(27) + (28)+(29)	$8.89	$10.45	$34.54	$37.53	$9.53	$11.43	$16.00	$0.76	$1.38

New & Existing Light Type	Annual Bill Quantity	Current Monthly Rate	LED Weighted Monthly Rate Current	LED Weighted Monthly Rate (Rate Case) Proposed	LED MARGINAL RATE
LED10	**604.15**		**$ 15.44**	**$ 15.71**	**$10.56**
HPS23	557.78	$ 15.40			
MA20	-	$ 18.38			
MV11	8.03	$ 12.70			
MV21	38.34	$ 16.72			
LED13	**429.15**		**$ 20.32**	**$ 20.66**	**$12.13**
HPS44	381.86	$ 19.01			
MA110	29.90	$ 38.41			
MA36	17.39	$ 18.00			
MV35	-	$ 24.53			
MV55	-	$ 31.36			
LED20FLOOD	**1,730.04**		**$ 18.56**	**$ 18.98**	**$17.01**
400 MV	165.78	$ 17.35			
4CHPS	16.84	$ 12.94			
400 HPS	968.90	$ 18.90			
400 MA	578.52	$ 18.49			
LED30FLOOD	**378.55**		**$ 30.45**	**$ 30.96**	**$21.45**
1M-HPSF	1.08	$ 30.44			
1000-MV	376.23	$ 30.44			
1000-MA	1.25	$ 32.11			
LED3PT	**454.39**		**$ 9.83**	**$ 10.01**	**$11.00**
HPS9PT	273.60	$ 9.72			
MV6PT	180.78	$ 10.00			
LED5	**16,359.73**		**$ 7.32**	**$ 7.44**	**$9.14**
HPS14	195.86	$ 11.71			
HPS9	7,095.74	$ 7.52			
MA8	391.31	$ 8.46			
MV6	8,676.82	$ 7.01			
LED5PT	**47.51**		**$ 12.53**	**$ 12.75**	**$12.21**
HPS14PT	47.51	$ 12.53			
MA8PT	-	$ -			
LED8	**89.10**		**$ 13.64**	**$ 13.88**	**$9.75**
HPS19	88.10	$ 13.61			
MA14	1.00	$ 16.10			

Schedule 9

David G. Prazak

Schedule Number(s)	Schedule Description	Changes
All		• Updating all footers for the new successor to: • Approved: Bruce G. Gerhardson, Vice President, Regulatory Affairs
Index		• Removing "Prior Sheet" Column, as this is no longer applicable
4.01	Meter and Service Installations	• Including new language in paragraph 2 beginning "The Company will connect electric service to a previously served location" to define the four rules under which reconnection will occur
4.13	Account History Charge	• Defining to whom the charges will be applicable by including "by a landlord/building owner or other party" • Adding additional clarification by including "The Account History Charge shall not excel $100 per request set. The landlord/building owner or other third-party request must be accompanied by a signed release from each Customer."
5.01	Extension Rules and Minimum Revenue Guarantees	• Removing language in paragraph 1 regarding the energy adjustment rider and base costs of energy, as they are no longer applicable and adding "schedule(s) under which the customer is taking service." To complete the sentence • Removing language regarding the energy adjustment rider and base costs of energy in paragraph 3, as they are no longer applicable
5.04	Standard Installation	• Removing paragraph seven (duplication of paragraph 6) • Removing the language in paragraph 1 under *Service Installation* regarding the energy-cost recovery, as it is no longer applicable
9.01-15.00		• In the Description Box, updating the rate level from 50 to 52 for all rate codes
9.01	Residential Service	• Removing the designation of two levels, "First 1,000" and "Excess", of kWh charges as the rate design is changing to a single kWh charge • Removing paragraph 4 under 2. on page 2 regarding bills "rendered on a two-month basis" as this is no longer applicable • Rate Changes
9.02	Residential Demand Control Service	• Rate Changes
9.03	Farm Service	• Removing the levels of Three Phase designations to just Three Phase only with a single charge • Removing the designation of two levels, "First 1,000" and "Excess", of kWh charges as the rate design is changing to a single kWh charge • Rate Changes
9.04	Residential Time of Day Service – Pilot	• New Rate Schedule: Residential Time-of-Day Service - Pilot
10.01	Small General Service	• Under Application of Schedule: Adding "dusk to dawn" to clarify the hours of use under this schedule • Under Terms and Conditions, updating the language to explain that a customer will be moved to the General Service Schedule (10.02) during their next billing cycle if their Demand equals or exceeds 20kW three times within the recent 12 months • Rate Changes
10.02	General Service	• Under Application of Schedule: Adding "dusk to dawn" to clarify the hours of use under this schedule • Under Rate: Adding the language "Per annual Max. kW (Minimum 20 kW per Month)" under Facilities Charge per Month for clarity • Rate Changes
10.03	General Service – Time of Use	• Updating this schedule to General Service – Time of Use (currently called Large General Service) by: o Relocating the language from Schedule 10.04 Commercial Service – Time of Use: Description, Rate Codes, Application of Schedule, Rate definitions, Terms and Conditions, Definition of Declared, Intermediate and Off-Peak Periods by Season, Declared-Peak Notification, Determination of Demand

		• Adding additional language to the "Definition of Declared, Intermediate and Off-Peak Periods by Season" section to better define the Declared-Peak, Intermediate, and Off-Peak designations • Rate Changes
10.04	Large General Service	• Updating this schedule to Large General Service (currently called Commercial Service – Time of Use) by: o Relocating the language from Schedule 10.03 Large General Service: Description, Application of Schedule, Rate definitions (including tiered Facilities Charges), Definition of Seasons, Determination of Facilities Charge, Determination of Billing Demand, Adjustment for Excess Reactive Demand • Removing the designation of two levels, "First 1,000" and "Excess", of kWh charges under each of the Primary, Secondary and Transmission rate definitions as the rate design is changing to a single kWh charge • Including "(Minimum of 80 kw) under our Demand Charge per kw under each of the Primary, Secondary and Transmission rate definitions for clarity • Rate Changes
10.05	Large General Service – Time of Day	• Removing "Experimental" from the name of this schedule, including the header • In the Rate box, including (Minimum of 80 kW per Month) under the Demand Charge per kW under each of the Primary, Secondary and Transmission rates • Updating the Definition of On-Peak, Shoulder and Off-Peak Periods by Season to the new Time of Day time periods • Rate Changes
10.06	Super Large General Service – Applications and Eligibility Requirements	• New Rate Schedule: Super Large General Service – Applications and Eligibility Requirements
11.01	Standby Service	• Relocating the order of seasonal information, both Summer and Winter, for consistency with other schedules • Adding specific hours for the Off-Peak timeframes • Rate Changes
11.02	Irrigation Service	• Including additional definition to the Winter and Summer season for better clarity • On Page 3, adding Declared-Peak Notification paragraph to provide definition of expectations • Rate Changes
11.03	Outdoor Lighting – Energy Only	• Changing Rate Code 744 to "Closed to New Installations" • Rate Changes
11.04	Outdoor Lighting	• Including the designation of "Closed to New Installations and Replacements" for each Rate Code within the Description area, as the rates within the new LED Schedule 11.07 will provide service for Outdoor Lighting • On Page 2 under section "Underground Service", removing the words "or sign" as it is not applicable • Rate Changes
11.05	Municipal Pumping Service	• In the Rate box for both Secondary and Primary, including "Annual Maximum kW per" to provide more clarity to the required Facilities Charge • Rate Changes
11.06	Civil Defense – Fire Sirens	• Rate Changes
11.07	LED Street and Area Lighting – Dusk to Dawn	• New Rate Schedule: LED Street and Area Lighting - Dusk to Dawn • Rate Changes
12.00	Purchase Power Riders & Applicability Matrix	• Including new rows for the following new rates and checking the applicable Small Power Producer Riders: o Under Residential & Farm Services: Residential Time of Day Service (9.04) o Under General Services: Super Large General Service (10.06) o Under Other Services: LED Street and Area Lighting (11.07)

		• Under General Services, modifying the rows for General Service – Time of Use and Large General Service to reflect the schedule number change for each
13.00	Mandatory Riders & Applicability Matrix	• Including new rows for the following new rates and applying the proper setting for the applicable Mandatory Riders: Page 1: ○ Under Residential & Farm Services: Residential Time of Day Service (9.04) ○ Under General Services: Super Large General Service (10.06) ○ Under Other Services: LED Street and Area Lighting (11.07) Page 2: ○ Under Mandatory Riders: Generation Cost Recovery Rider (13.06) • Under General Services, modifying the rows for General Service – Time of Use and Large General Service to reflect the schedule number change for each • Under Mandatory Riders, moving Transmission Cost Recovery Rider (13.05) below Renewable Resource Cost Recovery Rider to fall in line with the section numbers • Under Mandatory Riders, setting 13.07 to "Reserved for Future Use" due to the move of the Transmission Cost Recovery Rider to 13.05 • Under Voluntary Riders, setting 14.12 to "Reserved for Future Use" due to the cancellation of the Released Energy Access Program Rider • Updating the column for section 13.05 for the Transmission Cost Recovery Rider and carrying over the proper Base Tariff settings for this rider • Updating the column for 13.06 for the Generation Cost Recovery Rider and applying the proper settings for the Base Tariffs • Setting the column for 13.07 to "Reserved for Future Use" due to the move of the Transmission Cost Recovery rider to 13.05
13.01	Energy Adjustment Rider/Energy Adjustment Rider by Service Category	• Providing two versions of this Schedule: Energy Adjustment Rider and Energy Adjustment Rider by Service Category; Both include: ○ Additional language to the Energy Adjustment Charge section to define how this charge will be applied ○ A new section titled "Energy Adjustment Factor (EAF) to define how the EAF is calculated, including a table of each Service Category, the applicable Schedules, and the EAF Ratio for that category ○ The average cost of energy has been modified to include the addition of language in section 1. regarding the included costs of reagents and emission allowances • Energy Adjustment Rider has a set EAF Ratio of 1.000 for all categories due to the limitations within our current CIS system • Energy Adjustment Rider by Service Category has a unique EAF Ratio for each of the categories in preparation for our new CIS system • Rate Changes
13.04	Renewable Resource Cost Recovery Rider	• Rate Changes
13.05	Transmission Cost Recovery Rider	• This tariff will be Cancelled as the Economic Development Cost Removal Rider • This tariff is becoming the Transmission Cost Recovery Rider for consistency with our schedules within the Company – relocating all language from 13.07 to 13.05
13.06	Generation Cost Recovery Rider	• New Rate Schedule: Generation Cost Recovery Rider
13.07	Cancelled/Reserved for Future Use	• This tariff will be closed and Reserved for Future Use as the Transmission Cost Recovery Rider moves to 13.05
14.00	Voluntary Riders – Applicability Matrix	• Including new rows for the following new rates and applying the proper setting for the applicable Voluntary Riders: ○ Under Residential & Farm Services: Residential Time of Day Service (9.04) ○ Under General Services: Super Large General Service (10.06) ○ Under Other Services: LED Street and Area Lighting (11.07)

		• Under General Services, modifying the rows for General Service – Time of Use and Large General Service to reflect the schedule number change for each • Setting the column for 14.11 to "Reserved for Future Use" due to the cancellation of the Released Energy Access Program Rider and removing the checks from all rows
14.01	Water Heating Control Rider	• Rate Changes
14.02	Real Time Pricing Rider	• Rate Changes
14.03	Large General Service Rider	• Administrative Charge Rate Change
14.04	Controlled Service – Interruptible Load CT Metering Rider (LDF)	• In the Availability section, including additional language to more clearly define the acceptable loads and back-up system options • Rate Changes
14.05	Controlled Service – Interruptible Load Self-Contained Metering Rider (SDF)	• In the Availability section, including additional language to more clearly define the acceptable loads and back-up system options • Within the Rate table on page 2, changing "INTERR" to include the full word "INTERRUPTIBLE" • Rate Changes
14.06	Controlled Service Deferred Load Rider	• In the Availability section, correcting grammar and including additional language to more clearly define the acceptable loads • Rate Changes
14.07	Fixed Time of Service Rider	• In the Availability section, including additional language to more clearly define the acceptable loads • Updated title of Section from Fixed Time of Delivery to Fixed Time of Service • Rate Changes
14.08	Air Conditioning Control Rider (Cool*Savings*)	• Adding a new Rate 52-762 with description of "Commercial Air Conditioning Control Rider" • Modifying the Availability section to define the addition of customer groups to "Residential, Residential associated with a Farm and Commercial Customers", equipment requirements to include heat pumps, and to whom these rates will be unavailable • Under the Compensation section, designated the existing language for the Residential (52-760) rate and added an addition paragraph for Commercial (52-762) and the applicable compensation details • Updating 2. under the Terms and Conditions section, to more clearly define the responsibility of costs regarding non-standard facilities • Under Terms and Conditions, adding 6. for a description of how Commercial cooling will be controlled • Rate Addition and Change
14.09	Voluntary Renewable Energy Rider (Tail*Winds*)	• Rate Change
14.10	WAPA Bill Crediting Program Rider	• No language changes
14.11	Reserved for Future Use	• Cancelling the existing Released Energy Access Program (REAP) Rider • Reserving for Future Use
14.12	Bulk Interruptible Service	• No language changes