BEFORE THE NORTH DAKOTA PUBLIC SERVICE COMMISSION
STATE OF NORTH DAKOTA

IN THE MATTER OF THE APPLICATION OF OTTER TAIL POWER COMPANY FOR AUTHORITY TO INCREASE RATES FOR ELECTRIC UTILITY SERVICE IN NORTH DAKOTA

CASE NO. PU-23-342

EXHIBIT ____ (KM-1)

DIRECT TESTIMONY AND EXHIBITS OF

KAVITA MAINI

ON BEHALF OF

MIDWEST LARGE ENERGY CONSUMERS

OCTOBER 4, 2024

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Prefiled Kavita Maini Direct Testimony and Exhibits - Redacted
Midwest Large Energy Consumers
Richard Savelkoul, Martin & Squires, PA

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I. INTRODUCTION

Q. Please state your name and occupation.

A. My name is Kavita Maini. I am the principal and sole owner of KM Energy Consulting, LLC.

Q. Please state your business address.

A. My office is located at 961 North Lost Woods Road, Oconomowoc, WI 53066.

Q. Please state your educational and professional background.

A. I am an economist with over 32 years of experience in the energy industry. I graduated from Marquette University, Milwaukee, Wisconsin with a master's degree in business administration and a master's degree in applied economics. From 1991 to 1997, I worked for Wisconsin Power & Light Company ("WP&L") as a Market Research Analyst and Senior Market Research Analyst. In this capacity, I conducted process and impact evaluations for WP&L's Demand Side Management ("DSM") programs. I also conducted forward price curve and asset valuation analysis. From 1997 to 1998, I worked as Senior Analyst at Regional Economic Research, Inc. in San Diego, California. From 1998 to 2002, I worked as a Senior Economist at Alliant Energy Integrated Services' Energy Consulting Division. In this role, I was responsible for providing energy consulting services to commercial and industrial customers in the area of electric and natural gas procurement, contract negotiations, forward price curve analysis, rate design and on-site generation feasibility analysis. I was also involved in strategic planning and due diligence on acquisitions.

Since 2002, I have been an independent consultant. In this role, I have provided consulting services in the areas of class cost of service studies, rate design, revenue allocation, resource planning and revenue requirement related issues, Midcontinent Independent System Operator ("MISO") related matters and various policy matters. I also represent industrial trade associations at MISO's various task forces and committees and am the End Use Sector representative at MISO's Advisory and Planning Advisory Committees.

Q. Have you participated in utility related proceedings?

A. Yes, I have testified before a number of state regulatory commissions, including in Wisconsin, Minnesota, Missouri, Iowa, North Dakota and South Dakota. I have testified on a variety of issues related to revenue requirements, resource planning and generation resource acquisition, cost of service, revenue allocations and rate design. I have also provided technical comments in Federal Energy Regulatory Commission ("FERC") proceedings, several of which have involved MISO-related activities.

Q. On whose behalf are you testifying in this proceeding?

A. I am testifying as an expert witness on behalf of the Midwest Large Energy Consumers Group ("MLEC"). MLEC is an ad-hoc group of large industrial customers[1] taking service from Otter Tail Power Company ("OTP" or "Company") on its Large General Service rate schedules.

Q. Is MLEC sponsoring additional witnesses in this case?

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[1] Membership includes Tharaldson Ethanol, Applied Digital Corporation, ADM Northern Sun, Cavendish Farms, Doosan Bobcat, Walmart, Green Bison Soy Processing, North Dakota Soybean Processors, Enbridge, and ComDel Innovation.

A. Yes. MLEC is also sponsoring the testimony of Steve Chriss.

Q. How are the companies represented by MLEC impacted by this proceeding?

A. MLEC members represent large employers that operate energy intensive facilities and compete in a regional and national environment. Therefore, energy costs are typically among the largest costs of doing business for these companies. Thus, energy affordability affects the competitiveness, output and potential employment levels for these companies.

In this rate case proceeding, OTP proposes an approximately $22.5 million increase in base rate revenue requirement or 10.9% increase on a systemwide basis. For this increase, OTP proposes a 9.8% increase to the LGS class while the Company's own cost of service study supports a much lower increase at 4.2% for this class. The large commercial and industrial customers members served by OTP will therefore be significantly impacted by the outcome of this proceeding.

Q. What is the purpose of your testimony?

A. The purpose of my direct testimony is to address and recommend issues related to revenue requirement, sale adjustment proposal, class cost of service, revenue apportionment to customer classes, and rate design issues related to the LGS class.

The rest of my testimony is organized as follows:

Section II: Revenue Requirement Issues

Section III: Sales Adjustment Rider

Section IV: Cost of Service

Section V. Revenue Requirement Allocation

Section VI: LPS and LGS Rate Design

II. REVENUE REQUIREMENT ISSUES

1. Langdon Upgrade

Q. What is OTP's proposal regarding the revenue requirements associated with the Langdon Upgrade?

A. The Company indicates that because the Langdon Upgrade is expected to be in service in the Test Year (i.e.,2024), it proposes to include an adjustment to annualize the costs associated with the Langdon Upgrade and fold these costs into base rates. OTP provided the calculation of the revenue requirements to be folded into base rates in response to MLEC-103 NOT PUBLIC (**Exhibit KM-1**) and as shown in Table 1 below. As can be observed, OTP proposes to incorporate $3,137,649 in base rates and $2,412,287 in production tax credits (PTC) are to be credited in the Renewable Cost Recovery Rider (RCRR).

Table 1: Annualized Revenue Requirements for Langdon Upgrade

Langdon Upgrade Project Revenue Requirement Included in Proposed Base Rates	
Plant Balance	$ 49.005.154
Accumulated Depreciation	$ (1.464.711)
ADIT	$ (1.182.769)
	$ 46.357.674
Current Rate of Return	$ 3.639.077
Income Tax	$ 587.629
Property Tax	$ 98.500
Book Depreciation	$ 2.929.419
Total Company Revenue Requirement	$ 7.254.626
ND Share Revenue Requirement in Proposed Base Rates	**$ 3,137,649**
ND Renewable Resource Rider	
Levelized Langdon Upgrade PTCs	$ (1.823.571)
Tax Conversion Factor	1.322837
PTCs credited in ND RRCR	$ (2.412.287)
Net ND Revenue Requirement in Base Rates and RRCR	$ 725.361

Q. What is the expected in-service date for the Langdon Upgrade?

A. In response to MLEC-103, OTP indicated that the Langdon Upgrade Project is expected to be in service in November 2024.

Q. What is your recommended approach for cost recovery associated with the Langdon Upgrade Project?

A. Since the expected in-service date is close to the end of the test year and the Company has an existing mechanism to recover the costs of renewable generation through the RCRR, I recommend that the Company recover the Langdon Upgrade Project related costs through this rider. According to Ms. Paula Foster's direct testimony on page 5, the Company plans to recover the costs associated with other Upgrade Projects including Luverne, Ashtabula I and Ashtabula III through the RCRR. Further, the Langdon Upgrade related costs are currently in the rider and OTP proposes to fold into base rates when final rates go into effect. I am recommending that the Langdon Upgrade related costs remain in the rider instead of getting folded into base rates.

The rider recovery will allow for savings associated with accumulated depreciation and other adjustments to rate base on an annual basis. If the costs are folded into base rates, customers will pay the higher front end loaded costs and not receive the benefits from the downward rate base adjustments until the next base rate case. OTP provided a detailed five year projection of revenue requirements through RCRR in response to MLEC-103. Table 2 below shows a comparison of the return on rate base via rider recovery versus folding in base rates.

Table 2: Return on Rate Base: RCRR v. Base Rate Recovery

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There would be additional savings associated with income taxes as well due to the lower return (equity portion) compared to folding into base rates while other costs such as depreciation and property taxes would be the same under either option.

2. Treatment of Levelized PTCs

Q. What approach is used to credit PTCs to customers?

A. OTP utilizes a levelized approach to credit PTCs. This approach consists of estimating the total PTCs that are expected to be generated and calculating an annual amount by dividing the total PTC credits by the life of the wind project. For instance, the Company provided a levelized calculation associated with Merricourt in response to MLEC-104 (**Exhibit KM-2**), which is provided as Table-3 below. The Merricourt PTCs are levelized in this manner per the Order in ND Case No. PU-19-387.

Table 3: Levelized PTCs for Merricourt

		Merricourt		
		Actual Production		
Year	**Federal PTC Rate**	**MWh Production**	**Federal PTC Available Based on Production**	**Total PTCs minus levelized amount**
2020	$25	50,011	$1,250,284	
2021	$25	500,119	$12,502,981	$8,025,508
2022	$26	576,333	$14,984,660	$10,507,187
2023	$28	589,968	$16,519,101	$12,041,628
2024	$28	582,530	$16,310,836	$11,833,363
2025	$28	570,410	$15,971,484	
2026	$29	571,231	$16,565,702	
2027	$29	569,319	$16,510,250	
2028	$29	569,358	$16,511,382	
2029	$30	569,358	$17,080,740	
2030	$30	416,804	$12,504,120	
	OTP Total	5,565,442	$156,711,540	$42,407,685
	OTP ND			$18,341,324
35-year Levelization			$4,477,473	
Monthly levelized amount			$373,123	

The annual PTCs credited to customers through the RCRR are based on OTP's expectation of actual production. As per the information provided above, the expected credit to customers is $4,477,473 on an annual basis at the present time. Since the actual annual generated PTCs are higher than the levelized PTCs, the remaining amount is recorded as a regulatory liability. Assuming that the 2024 levelized PTCs were credited to customers through the Rider, I estimate that so far, $18.3 million in PTC credit were generated but not credited to customers in North Dakota jurisdiction.

Q. Does OTP offset the rate base with this PTC related regulatory liability?

A. No. In response to MLEC-127 (**Exhibit KM-3**), OTP states the following in part:

> *PTCs recorded on the books before they are credited to customers are recorded as a regulatory liability. This regulatory liability does not reduce rate base and will unwind as the levelized PTCs are realized past the time when PTCs are generated through the Renewable Resource Cost Recovery Rider revenue requirement.*

Q. What do you recommend?

A. I recommend that the PTCs booked as regulatory liability be used to offset the rate base in the same manner as accumulated deferred income taxes (ADIT). This regulatory liability consists of PTC credits that have already been generated but not released to customers. For illustrative purposes and using Merricourt as an example, I calculate that the impact would be a reduction of $1.9 million in revenue requirement.

Regulatory Liability	$18,341,324
Rate of Return	7.85%
Grossed Up Return	10.38%
Impact	**$1,904,613**

While I use the Merricourt generation related example here, I recommend the same treatment for all current and forthcoming projects that will utilize the levelized PTC treatment. Further, I recommend that this offset be credited to customers through the

RCRR in the annual filings. Finally, I recommend that the Company provide a schedule of these impacts in rebuttal testimony.

3. Large Regional Projects

Q. What are large regional projects?

A. The large regional projects designated as Multi-Value Projects or MVPs are developed through a top-down planning process by the Mid-Continent Independent System Operator (MISO). The costs associated with these projects are socialized by load on a sub-regional basis. The first MVP portfolio was approved by the MISO Board in 2011. OTP invested $188 million in two projects from the first MVP portfolio. In 2022, the second MVP portfolio was approved by the MISO board and OTP's capital investment is estimated at $420 million.

Q. What is OTP's proposal to treat OTP's investment in large regional projects in the rate case?

A. OTP proposes to direct assign such investment to the FERC jurisdiction. OTP has removed the capital investment related costs associated with MVPs and assigned them to the FERC jurisdiction. The cost of service study shows that in this case, $274 million of 33% of total transmission plant in service ($824.7 million) is direct assigned to the FERC jurisdiction. As noted above, the FERC jurisdictional amount will increase substantially as OTP constructs the two MVPs estimated at $420 million.

Q. Are rate base related costs the only cost components associated with such projects?

A. No. I expect that the Company incurs operation and maintenance (O&M) costs including and not limited to labor, external services and legal functions. The development of the MVP portfolio is time intensive and requires substantive involvement particularly by transmission owning entities who have an interest in developing and investing in MVP projects. The development cycle is time consuming and spans years, not months. Further, the implementation phase involves various regulatory activities and compliance.

Q. Are such operations and maintenance costs direct assigned to the FERC jurisdiction?

A. I am not certain that all costs are properly assigned. Table 4 shows some categories of transmission expenses from the cost of service study. This list may not be exhaustive. The Regulatory Commission Expense category appears to be the only one that is categorized as directly assigned.

Table 4: Transmission O&M Allocation

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Q. What is your recommendation?

A. I recommend that the Company implement direct assignment of all the O&M costs associated with the MVP investment that is designated to the FERC jurisdiction. OTP should provide this assignment along with justification for each of the categories in rebuttal testimony. OTP needs to demonstrate that the O&M costs are assigned in a manner commensurate with the level of effort associated with developing and implementing MVPs. If it is not practically possible to directly assign a specific cost category, one reasonable approach could be to base the O&M cost allocation on the level of transmission net plant in service related to MVPs as a percent of the total net transmission plant in service.

III. SALES FORECAST AND SALES ADJUSTMENT PROPOSALS

1. Sales Forecast for LGS Class

Q. What is the Company's methodology for forecasting sales associated with the LGS class?

A. OTP utilizes a statistical model to forecast sales for large commercial and industrial customers. In addition, the Company makes manual adjustments for pipeline, customers that installed self-generation and other customers that do not fit the modeling process. In this rate case, OTP made a handful of such adjustments. I believe additional adjustment should be made to some of the Company's proposed usage.

Q. Did OTP include the new load associated with the North Dakota Soybean Processing plant that had a ribbon cutting ceremony on August 7, 2024?

A. No. In response to MLEC-130 NOT PUBLIC (**Exhibit KM-4**), OTP indicated the following: **[PROTECTED DATA BEGINS...**

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Q. Please comment on OTP's response.

A. The news release issued regarding the North Dakota Soybean processing plant on August 7, 2024 indicates the following:

> *Construction on the state-of-the-art facility started nearly two years ago, and it began accepting soybeans in July. During its first year of operation, the plant is expected to process up to 42.5 million bushels of soybeans into soybean oil, soybean meal and soybean hull pellets. The facility employs about 75 people.*

It would seem that the soybean processing and electric consumption has started since this facility began accepting soybeans in July. Consequently, it makes sense to adjust the sales forecast to include this load. Since the facility is up and running, there should be more certainty about the load associated with this facility. Further, discussions with this plant's personnel has indicated that the plant has been testing equipment in the last couple of weeks, plans to start running at normal operation next week and be at full load by November. The plant expects to have full load by November. Given that it is a known and material change, I recommend that OTP incorporate the annualized sales revenues associated with this load, OTP needs to provide an estimate of this adjustment in rebuttal testimony.

Q. Are there other changes that are necessary?

A. Possibly, I am continuing to review the manual adjustments made for accuracy considering we have actual consumption from these customers.

2. *Sales Adjustment Proposals*

Q. What are the Company's sales adjustment proposals?

A. The Company proposes the following for the time period in-between rate cases:

- A new mandatory rider called the Sales Adjustment Rider (SAR) to capture the effect of sales changes on base rate jurisdictional allocations and revenues; and
- A request for authorization to update jurisdictional allocators used to develop rider revenue requirements between rate cases.

The sales rider would reconcile the impact of changes in sales on an annual basis and on base rates. Each year, the Company proposes to: (a) compare the authorized sales and base rate revenue requirement in this case with the actual sales; (b) estimate the impact of actual sales on allocation factors, base revenues and associated working capital leaving all else unchanged and (c) calculate the difference between the two cases to either charge or credit customers using a $/kWh charge.

The proposal to change the jurisdictional allocator change would potentially capture the changes between jurisdictions as a result of a change in sales.

Q. What is the Company's justification for these proposals?

A. Mr. Bruce Gerhardson explains that the Company could potentially experience significant changes in sales between rate cases. The sales adjustment proposals would allow the Company to address the impacts of sales changes on revenues and jurisdictional cost allocations.

Q. What is your response to these proposals?

A. While I recognize that OTP had experience with material changes in sales in the recent past, I am very concerned about adding another rider to the long list of revenue requirement items that are currently authorized for rider recovery, which further exacerbates piecemeal ratemaking and increases administrative and regulatory burden. Further, the SAR would ignore any efficiency gains in O&M costs that the utility might have achieved as a result of replacing aging infrastructure. It should be noted that while the capital investment related costs associated with generation, transmission, metering and environmental compliance can be recovered through riders, any O&M cost savings are not passed through. As it relates to the jurisdictional allocation changes, other OTP jurisdictions have not authorized such a proposal. If other jurisdictions retain the allocators from the rate cases in their respective jurisdictions, implementation of the Company's proposal only in North Dakota will result in unintended consequences. For all these reasons, I am not supportive of the Company's sales adjustment related proposals and recommend that the sales adjustment rider related proposals be rejected.

IV. COST OF SERVICE

1. Importance of A Utility's Cost of Service Study (COSS)

Q. What is the importance of a utility's cost of service study?

A. A utility's cost of service study is the fundamental basis for establishing just and reasonable rates in the ratemaking process. The cost of service study helps determine a utility's revenue requirement, guides revenue allocation to classes and informs rate design.

Revenue Requirement: A utility's cost of service is used in the determination of the revenue requirement of the utility and whether an increase, decrease or no change is necessary. Efforts are made to align total company rate revenues with the utility's cost of service.

Revenue Allocation to Classes: Given a certain revenue requirement, a utility's cost of service study guides the way in which a given revenue requirement should be allocated to classes. The level of the revenue requirement for each class should be based primarily on aligning each class's revenues with its cost of service providing the same or equal rates of return.

Setting Rates: For a certain revenue allocation to each class, a utility's cost of service also informs the design of class rates by setting rates with the goal of providing appropriate pricing signals.

Q. For a given revenue requirement, what is the impact of closely aligning rates with the costs to serve each class?

A. Provided that the class cost of service study is properly developed to reflect cost causation, closely aligning rates with each class's cost of service fulfills the important goals of promoting equity among classes and encouraging economic efficiency.

Q. Please explain how equity is promoted among classes.

A. If rates are aligned with the cost of service, then equity is promoted because each class pays its fair share of costs. Given this, a class that has rates that are not recovering its cost of service should receive an above system average increase while a class paying rates above cost of service should receive a below average increase. In cases where the class revenues are significantly misaligned with cost responsibility, larger corrections or adjustments may be warranted in order to restore equity among classes.

Q. How is economic efficiency achieved?

A. If retail rates align with the cost of service, then they provide accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs.

A. OTP's COSS

Q. Is OTP using the same allocators and COSS approach as the last rate case?

A. Yes. As indicated by Ms. Amber Stalboerger in her direct testimony, aside from certain refinements in the calculation of certain allocators, the methodology is the same as the last rate case.

Q. Are you recommending an alternative COSS in this case?

A. No. While I would have preferred to propose an alternative for classification of production plant related costs in lieu of the equivalent peaker method utilized by the Company, in the interest of narrowing the issues, I will not pursue an alternative at this time.

With regards to distribution related plant related costs, the Company has utilized the minimum size or system method to classify distribution plant related costs for certain FERC accounts as customer and demand related. The Company utilized the same method in the last rate case. The minimum distribution approach is a long established approach, widely used by utilities and recognized in the NARUC manual. I support this approach as it recognizes the basic premise that that the distribution system exists to serve a dual purpose: 1) being capable of delivering service to customers' residences or businesses (customer costs), and 2) ensuring that the distribution system is large enough to provide reliable service (demand costs).

B. OTP's COSS RESULTS

Q. Please explain how the COSS results are typically shown.

A. Upon completion of the class cost of service study, the net income for each class (revenues less expenses) is divided by the rate base dedicated to serving that class to calculate the rate of return earned at present rates. To the extent that a class rate of return (ROR) is greater than the system return, then the revenues recovered from the class are more than the costs to serve that class. Similarly, to the extent that a class rate of return is lower than the system return, then the revenues recovered from the class are less than the costs to serve this class. Table 5 shows the ROR and relative ROR at present rates.[2] As can be observed from OTP's COSS results, the Company earned a below system average return from the residential class (0.84%) and above system average return from the general service (3.19%), lighting (9.46%) and large general service (4.38%) respectively. The Company earned a negative return from the irrigation and OPA classes, meaning that this class's revenue was not enough to cover its expenses. For other classes such as farms and controlled service (consolidated), OTP earned just below the system average. The relative ROR metric similarly shows the same result from a relative perspective between classes. That is, the higher the value

[2] See Exhibit___(AMS-2), Schedule 1, Ms. Amber Stalboerger Supplemental Direct.

above 1, the larger the class revenues are above the class costs and vice versa.

Table 5: OTP's COSS Earned Rate of Return ("ROR") and Relative ROR by Class at Present Rates

Item	North Dakota	Residential	Farms	General Service	Large General Service	Irrigation	Outdoor Lighting	OPA	Controlled Service
Rate Base	695,424,815	215,995,994	11,399,807	155,262,442	237,067,236	612,155	14,072,417	6,423,958	54,590,806
Total Available for Return	19,989,879	1,821,704	306,981	4,956,795	10,384,769	(9,410)	1,330,747	(86,935)	1,285,227
Rate of Return Earned at Present Rates	**2.87%**	**0.84%**	**2.69%**	**3.19%**	**4.38%**	**-1.54%**	**9.46%**	**-1.35%**	**2.35%**
Relative Rate of Return	**1.00**	**0.29**	**0.94**	**1.11**	**1.52**	**-0.53**	**3.29**	**-0.47**	**0.82**

Q. How are ROR related insights used?

A. These insights are used as guidance in developing the revenue allocation recommendation.

V. REVENUE REQUIREMENT ALLOCATION

Q. What should be the primary guiding principle in establishing fair and reasonable rates?

A. A properly developed COSS is important to establishing fair and reasonable rates. It is used to determine revenue requirement for the Company and should be used as the primary guiding principle in allocating revenue requirement to classes and informing rate design. Also as discussed earlier in my testimony, such an approach fulfills the important goals of promoting equity among classes and encouraging economic efficiency. If revenues are allocated to classes and align closely with the class cost responsibility, equity is maintained because each class pays its fair share of costs. Further, if retail rates align with cost of service, they reflect accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs.

Q. Can other factors be also considered?

A. Yes. Other factors such as gradualism and rate continuity may also be considered. At the same time, however, these factors should not be the dominating elements such that there is little to no movement towards cost responsibility. We must also weigh in the fairness consideration and not ignore the important aspect that when one class is not paying their full share, one or more classes are being asked to pay more than their cost responsibility.

Q. What is the Company's revenue allocation proposal?

A. Table 6 shows a comparison of the Company's revenue allocation to the COSS results and the deviation from COSS results. The Company's present revenues are inclusive of rider recovery absent a rate case and used as the baseline to calculate the rate increases. The last two columns show the level of cross subsidy in dollar and percent terms under the Company's proposal. A positive deviation from the COSS results means that the class is not paying its fair share and is getting subsidized, and a negative deviation means that the class is paying more than its fair share and is subsidizing other classes.

Table 6: OTP's Revenue Allocation Proposal Compared to OTP COSS Results

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OTP provided the class ratios associated with its proposed revenue allocation as shown on Table 6.[3] The class ratios are calculated by dividing the class increase by the system increase. While the Company did not explicitly state how this ratio might be applied, I assume the Company proposes to use the ratios to calculate the final class increase. For instance, if the final rate increase is 5%, the applicable rate increase to the General Service class will be 1.20 X 5% = 6% and so on. I support the methodology of applying class ratios to the final increase. However, I have an alternative recommendation for the Commission's consideration regarding the class ratios.

Q. Prior to discussing MLEC's recommendation, what are your observations regarding OTP's revenue allocation proposal?

A. While OTP has made some movement towards getting classes closer to costs to serve, the Company's recommendation results in some within the LGS class receiving much

[3] See Table 1, Stalboerger Supplemental Direct.

higher increases and far exceeding the system average increase, meaning that many or even most will be moved even further from cost, which is directionally not consistent with OTP's COSS results. My proposal will ensure that all of North Dakota's employers are moving closer to cost and remain competitive with those outside of North Dakota.

Q. What is MLEC's recommendation?

A. MLEC's recommended class ratios are provided in Table 7. As can be observed from the last two columns in the table, this recommendation moves most classes closer to cost compared to the Company's proposal while continuing to moderate rate impacts for certain classes.

Outside of the rate case process, there is no practical opportunity to gets class revenue responsibility more closely aligned with class cost responsibility. The current rate case therefore provides a timely opportunity to align classes closer to their costs to serve and promote fairness between classes. I therefore recommend that the Commission adopt MLEC's revenue allocation and apply the class ratios (shown in

Table 7), to the final rate increase to calculate class rate increases.

Table 7: OTP's Revenue Allocation Proposal Compared to OTP COSS Results[4]

[PROTECTED DATA BEGINS...

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Q. What is your proposal to allocate the revenue allocation between the LGS and SLGS class?

A. I recommend that the percent revenue responsibility share remain the same as recommended by OTP. Table 8 demonstrates that under both OTP and MLEC revenue allocations, the percentage revenue responsibility assigned to LGS v. SLGS is the same.

[4] See responses to MLEC-704 PUBLIC (**Exhibit KM-5**) and MLEC-700 NOT PUBLIC Attachment 2 (**Exhibit KM-6**).

I note that this split is also consistent with the COSS results.

Table 8: Revenue Responsibility Share -LGS v. SLGS[5]

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VI. RATE DESIGN

Q. What is the Company's proposal to allocate the revenue allocation between the LGS primary and LGS secondary class?

A. Mr. Prazak indicates that the revenue allocation proposed for the LGS primary and secondary class uses the class level average increase recommended in revenue allocation.

Q. Do you have any concerns about this approach?

A. As discussed earlier, I am concerned about the Company's proposed revenue allocation to these classes which is not directionally consistent with the Company's COSS results. Aside from fairness and cost causation concerns, an over allocation of revenue responsibility will not result in providing efficient pricing signals.

Q. What method does OTP use to modify the various unit rate charges of the LGS

[5] See response to MLEC-704 NOT PUBLIC for OTP's split.

Secondary and LGS Primary rates?

A. The Company relies on a third party sourced Marginal Cost study to modify unit charges such as customer charges, facility charges, energy and demand charges. This study was conducted in August 2023.

Q. What are the proposed changes?

A. Table 9 shows the proposed charges. The biggest changes are to winter energy charges which are increasing by approximately 79%. Further, the winter demand charge is going from being lower than the summer charge to being much higher and the proposed increase is 42% compared to the existing charge.

Table 9: Proposed Charges for LGS Secondary and Primary Customers[6]

Charge	Units	Present Rate		Proposed Rate	
		Summer	Winter	Summer	Winter
10.04 Large General Service - Secondary Service (Rate 603)					
Customer Charge	Bills	$215.90	$215.90	$215.90	$215.90
Energy -All kWh	kWh	$0.02286	$0.02341	$0.03487	$0.04190
Demand per kW	kW	$10.75	$8.54	$12.09	$12.09
Facilities Charge <1,000 kW	kW	$0.76	$0.76	$0.76	$0.76
Facilities Charge >=1,000 kW	kW	$0.56	$0.56	$0.56	$0.56
Revenue Adjustment					
Base Revenue					
Air Conditioning Control Rider 14.08 (Rate 760)	Bills	-$8.25	-$8.25	-$8.00	-$8.00
TailWinds Program 14.09		$3.73	$3.73	$3.73	$3.73
WAPA Bill Credit 14.10					
WAPA, A/C, W/H, & Tailwinds					
10.04 Large General Service - Primary Service (Rate 602)					
Customer Charge	Bills	$282.00	$282.00	$282.00	$282.00
Energy -All kWh	kWh	$0.02224	$0.02264	$0.03403	$0.04062
Demand per kW	kW	$10.35	$8.15	$11.29	$11.69
Facilities Charge - All kW	kW	$0.48	$0.48	$0.52	$0.52

Q. What are your observations about the Company's proposed changes to the unit charges?

A. I am in the process of evaluating these charges and will provide more feedback in

[6] See response to MLEC-300 NOT PUBLIC Attachment 1 (**Exhibit KM-7**).

following rounds of testimony. The duo decile analysis submitted in response to MLEC-305 NOT PUBLIC (**Exhibit KM-8**) shows many customers in the secondary and primary class will be highly affected by this proposal. I am particularly concerned about the changes in the winter energy and demand charges. Mr. Prazak indicated that the marginal study provided this guidance. It is important to note that the marginal cost study relied in large part on the forward curve to provide a forecast for energy charges. The forward curve expectations change frequently based on a wide array of market related factors and represent the expectations at the specific moment in time. For instance, last august, the natural gas prices were high, and the forward curve reflected this expectation. I suspect that a comparison of the forward curve from August 2023 and August 2024 would likely show different results. I also note that the fuel adjustment charges provided in response to MLEC-312 (**Exhibit KM-9**) shows a slight downward shift in 2024 compared to 2023. The rate in 2023 is likely a typographical error and has a 0 before the $0.31.

Table 10: Energy Adjustment Rider Charges ($/kWh)

	2020	2021	2022	2023	(1) 2024
ND EAR	0.01588	0.02535	0.03098	0.31087	0.02979

(1) Calculated from EAR Data Used to Develop 2024 Test Year

Q. Does this conclude your direct testimony?

A Yes.

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: September 16, 2024
Responding Witness: Paula Foster, Supervisor Regulatory Analysis, 218-739-8042

Data Request:
Please provide the following regarding the Langdon Wind Repowering Project and provide quantitative data in excel spreadsheet format with formulae intact:

a. In-service date

b. Projected annual capacity factor and associated MWhs.

c. Revenue requirement breakdown by major components (return on rate base, depreciation, O&M expenses, taxes etc) that is proposed to be incorporated in base rates; this should the Company's proposal for annualizing the revenue requirements.

d. Provide a schedule that shows the proposed treatment and amount of the production tax credits included in rates or rider with reasons for this proposed treatment.

e. If the PTCs are levelized over the life of the project, how does OTP account for the remaining (unused) levelized PTC portion that is not used to credit customers? For instance, is this portion used to offset rate base? Please explain and provide the related working papers with your response.

f. Please provide a schedule that shows the projected revenue requirement for the next five years if Langdon related revenue requirements were to be recovered through the renewable rider.

Attachments: 2

Attachment 1 to DR ND_MLEC_103.xlsx
Attachment 2 to DR ND_MLEC_103_PUBLIC.pdf

Response:

Attachment 2 to DR ND-MLEC-103 contains trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, Attachment 2 to DR ND-MLEC-103 is a live excel version (with formulae intact) of OTP's RRCR Rider model, which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. To be clear, the data contained in Attachment 2 to DR ND-MLEC-103 is not trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4), nor is that data subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information.

a. The Langdon Upgrade Project is expected to be in service in November 2024.

b. The projected annual capacity factor for the Langdon Wind Facility after the Upgrade Project is completed is approximately 50 percent, and the associated MWhs with that capacity factor are projected to be 177,000 annually.

c. In reviewing information for this data request, a correction was identified related to the depreciable life of the Langdon Upgrade. The 2024 Test Year revenue requirement was calculated using a 35-year depreciable life for the Langdon Upgrade, commencing at the in-service date of the Upgrade. In preparing this response, we determined the Langdon Upgrade Project depreciable life should be equal to the approved remaining life for Langdon (18 years in 2024). This correction increases the 2024 Test Year revenue requirement by approximately $631,472 (OTP ND). An associated correction to the levelization of production tax credits (PTCs) increases annual credits by approximately $350,908, resulting in a net revenue requirement effect of approximately $280,564.

   OTP also identified a correction regarding the property tax expense associated with the Langdon Upgrade. OTP initially believed the Upgrade projects were not subject to additional property tax but has determined the Upgrade projects are subject to additional property tax. This correction increases the 2024 Test Year revenue requirement by approximately $42,602.

   As explained in the Direct Testimony of Paula Foster at page 7, we will provide updated information about the Langdon Upgrade as the case develops and ensure that final rates reflect updated project costs and the updated depreciable life and property tax. The estimated revenue requirement for the Langdon Upgrade, subject to final updates, is provided in Figure 1.

Figure 1

Langdon Upgrade Project Revenue Requirement Included in Proposed Base Rates		
Plant Balance	$	49,005,154
Accumulated Depreciation	$	(1,464,711)
ADIT	$	(1,182,769)
	$	46,357,674
Current Rate of Return	$	3,639,077
Income Tax	$	587,629
Property Tax	$	98,500
Book Depreciation	$	2,929,419
Total Company Revenue Requirement	$	7,254,626
ND Share Revenue Requirement in Proposed Base Rates	**$**	**3,137,649**
ND Renewable Resource Rider		
Levelized Langdon Upgrade PTCs	$	(1,823,571)
Tax Conversion Factor		1.322837
PTCs credited in ND RRCR	$	(2,412,287)
Net ND Revenue Requirement in Base Rates and RRCR	$	725,361

d. All PTCs are included in the RRCR Rider and are levelized per the Commission's Order dated March 27, 2024, in ND Case No. PU-23-343. As stated in Foster Direct, page 8, Otter Tail proposes to continue to include the PTC calculations in the RRCR Rider filings. Because wind facility production fluctuates and PTC rates are updated annually, the RRCR is the best mechanism to use to calculate PTCs and credit them to customer accounts.

As mentioned above, OTP identified a correction to the depreciable life of the Langdon Upgrade, which will increase annual PTC credits for customers. We will make this update in the next RRCR Rider filing.

Also, updated PTC rates were released in July 2024. Those updated rates increased the base PTC portion from $27.50 to $30.00 per MWh. Langdon also qualifies for two PTC adders totaling $6 per MWh. These updated rates are reflected in the PTC summary table, provided in Figure 2 below.

Figure 2 represents the calculation that will be used for the PTCs included in the RRCR for the Langdon Upgrade. The projected production section is used to establish RRCR Rider rates. As actual production figures are received, they are incorporated into the calculation through the actual production section, which is used to calculate the annual true up.

Figure 2

		Langdon Upgrade Project PTC Levelization			
		Projected Production		Actual Production	
Year	Estimated Projected Federal PTC Rate	Estimated Projected MWh Production	Federal PTC Available Based on Production	Actual/Estimated Projected MWh Production	Federal PTC Available Based on Production
2024	$36.00	32,773	$1,179,816	32,773	$1,179,816
2025	$37.00	177,000	$6,549,000	177,000	$6,549,000
2026	$39.00	177,000	$6,903,000	177,000	$6,903,000
2027	$40.00	177,000	$7,080,000	177,000	$7,080,000
2028	$42.00	177,000	$7,434,000	177,000	$7,434,000
2029	$43.00	177,000	$7,611,000	177,000	$7,611,000
2030	$44.00	177,000	$7,788,000	177,000	$7,788,000
2031	$45.00	177,000	$7,965,000	177,000	$7,965,000
2032	$46.00	177,000	$8,142,000	177,000	$8,142,000
2033	$47.00	177,000	$8,319,000	177,000	$8,319,000
2034	$48.00	144,227	$6,922,912	144,227	$6,922,912
		1,770,000	$75,893,728	1,770,000	$75,893,728
18-year Levelization					
OTP Total			$4,216,318		$4,216,318
OTP ND			$1,823,571		$1,823,571

The calculations included in Figure 2 are also provided in Attachment 1 to ND-MLEC-103.

e. As shown in Figure 2 above and Attachment 1 to DR ND-MLEC-103, the PTC levelization amount will include actual annual MWh production in the calculation to ensure all PTCs earned by OTP are reflected in the annual true-up, which is included in the calculation of the updated rates in each annual RRCR Rider filing. There will be no remaining or unused PTCs.

f. Figure 3 provides projections of the Langdon Upgrade revenue requirements if the project remained in the RRCR Rider. Note that the revenue requirements in Figure 3 reflect the approved remaining life for Langdon (18 years in 2024) and the updated PTC rates reflected in Figure 2 and discussed in subpart (d). The supporting documentation for Figure 3 is provided as Attachment 2 to DR ND-MLEC-103.

Figure 3
Annual Langdon Upgrade Project Revenue Requirements Including PTCs

Year	Revenue Requirement
2024	$ 988,963
2025	$ 772,731
2026	$ 677,707
2027	$ 610,811
2028	$ 554,695

[PROTECTED DATA BEGINS…

Case No. PU-23-342
Attachment 2 to DR ND-MLEC-103
is CONFIDENTIAL in its Entirety

…PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumers
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: August 12, 2024
Responding Witness: Paula Foster, Supervisor Regulatory Analysis, 218-739-8042

Data Request:
Regarding the Merricourt Wind Project, please provide the following with a narrative explanation and quantitative data in excel spreadsheet format where applicable:

a. Proposed revenue requirement breakdown by major components (return on rate base, depreciation, O&M expenses, taxes etc) that is proposed to be incorporated in base rates;

b. Estimated capacity factor (and associated MWhs) in application to seek approval to construct Merricourt and actual annual capacity factors (and associated MWHs) since in service.

c. Provide a schedule that shows the proposed treatment and amount of the production tax credits (PTC) included in rates or rider with reasons for this proposed treatment. To the extent that the PTCs are proposed to remain in the rider, please explain why they cannot be incorporated in base rates if all other components are being folded into base rates.

d. If the PTCs are levelized over the life of the project, how does OTP account for the remaining (unused) levelized PTC portion that is not used to credit customers. For instance, is this portion used to offset rate base? Please explain and provide the related working papers with your response.

Attachments: 2
Attachment 1 to DR ND-MLEC-104
Attachment 2 to DR ND-MLEC-104

Response:

a. The breakdown of the Merricourt Revenue Requirement that is proposed to be incorporated into base rates is shown in Figure 1 below.

Figure 1
Merricourt Revenue Requirement
Included in Proposed Base Rates

Plant Balance	262,783,883
Accumulated Depreciation	(28,848,580)
ADIT	(48,203,183)
	185,732,120
Curr Rate of Return	14,579,971
Income Tax	3,399,801
Operating Costs	6,552,729
Property Tax	694,276
Book Depreciation	8,343,651
Ashtabula III Revenue Requirement	33,570,428
ND Share Revenue Requirement	15,100,330

b. The Merricourt energy output was expected to be approximately 666,000 megawatt hours (MWh) annually, at a projected net capacity factor of 50.7 percent. The calculations in Figure 2 can be found in Attachment 1 to ND-MLEC-104.

Figure 2
Annual Capacity Factor Calculation

Merricourt Wind Energy Facility		
Year	**Annual MWh**	**Actual Annual Capacity Factor**
2020	50,011	
2021	500,119	38.06%
2022	576,333	43.86%
2023	595,359	45.31%
2024*	538,620	40.99%

* Acutals through July 2024; projected from August through December 2024

The lower actual capacity factor is due primarily to transmission constraints in the area. Transmission projects are in process that will alleviate the constraints and allow Merricourt to function at or near full capacity.

c. The Merricourt PTCs are levelized in the tracker per the Order in ND Case No. PU-19-387. Due to the fluctuation in production and changes in PTC rates, the PTCs are included in the Renewable Resource Cost Recovery (RRCR) Rider filings. If the PTCs were included in base rates, the fluctuations would still be captured and trued up in the rider filings. The calculations included in Figure 3 are also provided in Attachment 2 to ND-MLEC-104.

Figure 3
Merricourt PTC Levelization Calculation

		Merricourt			
		Projected Production		Actual Production	
Year	Federal PTC Rate	MWh Production	Federal PTC Available Based on Production	MWh Production	Federal PTC Available Based on Production
2020	$25	57,607	$1,440,175	50,011	$1,250,284
2021	$25	532,958	$13,323,960	500,119	$12,502,981
2022	$26	638,552	$16,602,352	576,333	$14,984,660
2023	$28	660,394	$18,491,032	589,968	$16,519,101
2024	$28	660,394	$18,491,032	582,530	$16,310,836
2025	$28	660,394	$18,491,032	570,410	$15,971,484
2026	$29	660,394	$19,151,426	571,231	$16,565,702
2027	$29	660,394	$19,151,426	569,319	$16,510,250
2028	$29	660,394	$19,151,426	569,358	$16,511,382
2029	$30	660,394	$19,811,820	569,358	$17,080,740
2030	$30	608,591	$18,257,730	416,804	$12,504,120
		6,460,466	$182,363,411	5,565,442	$156,711,540
35-year Levelization			$5,210,383		$4,477,473
Monthly levelized amount			$434,199		$373,123

d. As shown in Figure 3 above and Attachment 2 to ND-MLEC-104, the 35-year levelization amount includes actual annual MWh production, which flows through the true-up portion of the RRCR rider tracker and is included in the calculation of the updated rates in each annual filing.

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: August 30, 2024
Date Due: September 16, 2024
Date of Response: September 16, 2024
Responding Witness: Paula Foster, Supervisor Regulatory Analysis, 218-739-8042

Data Request:
Refer to response to MLEC-104 part d, the question also asked how the unused PTCs were accounted for – that is, are they booked as a regulatory liability?

Attachments: 0

Response:

There are no unused PTCs. All PTCs are credited to customers over the life of the facility through levelization, as ordered by the North Dakota Public Service Commission on March 18, 2020, in Case No. PU-19-387.

PTCs recorded on the books before they are credited to customers are recorded as a regulatory liability. This regulatory liability does not reduce rate base and will unwind as the levelized PTCs are realized past the time when PTCs are generated through the Renewable Resource Cost Recovery Riderrevenue requirement.

PU-23-342
EXHIBIT (KM-1), Exhibit KM-4 **NOT PUBLIC DOCUMENT – NOT FOR PUBLIC DISCLOSURE**

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: August 30, 2024
Date Due: September 16, 2024
Date of Response: September 16, 2024
Responding Witness: Tammy Mortenson, Senior Data Analyst, Business Planning, 218-739-8890

Data Request:
Refer to response to MLEC-113. Please respond to the following:

a. Does OTP take the manual adjustments for the four customers and adjust the C&I sales forecast from the regression results provided in response to MLEC-113 (attachment 1) to estimate the sales for Large Commercial and Pipeline Sales at 1,433,405,558 kWh (shown in Mortenson Direct Testimony, Table 2, page 19)? Please explain and provide the working paper or schedule which shows the calculation of the total kWh Large Commercial and Pipeline sales.

b. Regarding 113 (f), please provide an update given that the Company should have the information available in August 2024.

Attachments: 1

Attachment 1 to DR ND-MLEC-130_NOTPUBLIC.xlsx

Response:

Attachment 1 to DR ND-MLEC-130 contains trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, the data marked as NOT PUBLIC in Attachment 1 to ND MLEC-130 contains customer-specific energy usage information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

a.

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumers
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: August 12, 2024
Responding Witnesses: Amber Stalboerger, Manager, Regulatory Economics, 218-739-8728

Data Request:
Please provide all tables and schedules from Ms. Amber Stalboerger's supplemental testimony in excel spreadsheet format with formulae intact.

Attachments: 1
Attachment 1 to ND-MLEC-704_PUBLIC

Response:

Attachment 1 to ND-MLEC-704 is trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, Attachment 1 to ND-MLEC-704 is a live excel version (with formulae intact) of Otter Tail's present and proposed revenue model, which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Further, Attachment 1 to ND-MLEC-704 contains trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, the data marked as NOT PUBLIC in Attachment 1 to ND-MLEC-704 contains customer-specific energy usage information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

Please see Attachment 1 to DR ND-MLEC-704.

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumers
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: August 12, 2024
Responding Witnesses: Amber Stalboerger, Manager, Regulatory Economics, 218-739-8728

Data Request:
Please include the jurisdictional cost of service study to the class cost of service study spreadsheet and provide this spreadsheet in live format for the revenue requirements submitted in the initial filing on November 2, 2023 and the supplemental filing submitted on July 3, 2024.

Attachments: 2
Attachment 1 to ND-MLEC-700_NOTPUBLIC
Attachment 2 to ND-MLEC-700_NOTPUBLIC

Response:

Attachments 1 and 2 to ND-MLEC-700 are trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, Attachments 1 and 2 to ND-MLEC-700 are live excel versions (with formulae intact) of OTPs jurisdictional and class cost of service study, which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Further, Attachments 1 and 2 to ND-MLEC-700 contain trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, Attachments 1 and 2 to ND-MLEC-700 contain customer-specific energy usage information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

Please see Attachment 1 to ND-MLEC-700 (Direct Testimony) and Attachment 2 to ND-MLEC-700 (Supplemental Direct Testimony).

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumers
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: August 12, 2024
Responding Witnesses: Amber Stalboerger, Manager, Regulatory Economics, 218-739-8728

Data Request:
Please provide all tables and schedules from Ms. Amber Stalboerger's supplemental testimony in excel spreadsheet format with formulae intact.

Attachments: 1
Attachment 1 to ND-MLEC-704_PUBLIC

Response:

Attachment 1 to ND-MLEC-704 is trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, Attachment 1 to ND-MLEC-704 is a live excel version (with formulae intact) of Otter Tail's present and proposed revenue model, which derives independent economic value, actual or potential, from not being generally known to, and not being readily ascertainable by proper means by, other persons who can obtain economic value from its disclosure or use. Further, Attachment 1 to ND-MLEC-704 contains trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, the data marked as NOT PUBLIC in Attachment 1 to ND-MLEC-704 contains customer-specific energy usage information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

Please see Attachment 1 to DR ND-MLEC-704.

[PROTECTED DATA BEGINS…

Case No. PU-23-342
Attachment 2 to DR ND-MLEC-700
is CONFIDENTIAL in its Entirety

…PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumers
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: August 13, 2024
Responding Witness: David G. Prazak, Manager, Pricing & Rate Design - (218) 739-8595

Data Request:
Please provide Volume 3 (trade secret version) for Schedule E-1, Schedule E-2 in Excel spreadsheet format with formulae intact. Please provide these schedules submitted in direct testimony and supplemental testimony.

Attachments:
Attachment 1 to DR ND-MLEC-300_PUBLIC
Attachment 2 to DR ND-MLEC-300_PUBLIC

Response:

Attachments 1 and 2 to DR ND-MLEC-300 contain trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, Attachments 1 and 2 to DR ND-MLEC-300 contain customer-specific energy usage information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

Please refer to Attachment 1 to DR ND-MLEC-300 for live, excel versions of Schedules E-1 and E-2 from OTP's Supplemental Direct Testimony and Attachment 2 to DR ND-MLEC_300_NOTPUBLIC for live, excel versions of Schedules E-1 and E-2 from OTP's Direct Testimony.

Test Year 2024 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)		$ 32,153,465	$ 45,174,002	$ 13,020,537	40.49%
2	9.02 Residential Demand Control (Rate 241)		$ 4,780,572	$ 6,963,486	$ 2,182,914	45.66%
3		Total Residential:	$ 36,934,038	$ 52,137,488	$ 15,203,450	41.16%
4						
5	9.03 Farm Service (Rate 361)		$ 1,830,784	$ 2,618,128	$ 787,344	43.01%
6		Total Farm:	$ 1,830,784	$ 2,618,128	$ 787,344	43.01%
7						
8	10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)		$ 7,779,957	$ 11,586,483	$ 3,806,526	48.93%
9	10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)		$ 1,645	$ 1,886	$ 241	14.64%
10	10.02 General Service - 20 kW or Greater - Secondary Service (Rate 401)		$ 19,521,819	$ 26,793,339	$ 7,271,520	37.25%
11	10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)		$ 57,141	$ 69,191	$ 12,051	21.09%
12	10.03 General Service - Time of Use (Commercial TOU) - (Rates 708, 709, 710)		$ 6,204	$ 8,555	$ 2,351	37.90%
13		Total General Service:	$ 27,366,763	$ 38,459,453	$ 11,092,690	40.53%
14	**[PROTECTED DATA BEGINS...**					
15						
16						
18						
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22						
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17						
19						
20						**...PROTECTED DATA ENDS]**
24	11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)		$ 26,273	$ 35,807	$ 9,534	36.29%
25	11.02 Irrigation Service - Option 2 (Rates 704, 705, 706)		$ 30,252	$ 50,170	$ 19,917	65.84%
26		Total Irrigation:	$ 56,524	$ 85,977	$ 29,451	52.10%
27						
28	11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)		$ 95,933	$ 105,968	$ 10,035	10.46%
29	11.03 Outdoor Lighting - Non-Metered - Energy Only (Rate 749)		$ 97,067	$ 107,220	$ 10,153	10.46%
30	11.03 Outdoor Lighting - Signal (Rate 744)		$ 41,803	$ 46,176	$ 4,373	10.46%
31	11.04 Outdoor Lighting - Street & Area Lighting (Rate 741, 743)		$ 900,453	$ 980,941	$ 80,488	8.94%

32	11.07 LED STREET and AREA LIGHTING – DUSK TO DAWN (Rate 730, 731)	$ 1,457,801	$ 1,624,072	$ 166,270	11.41%
33	Total Lighting:	$ 2,593,058	$ 2,864,377	$ 271,319	10.46%
34					
35	11.05 Municipal Pumping - Secondary Service (Rate 872)	$ 818,301	$ 1,239,306	$ 421,005	51.45%
36	11.06 Civil Defense - Fire Sirens (Rate 843)	$ 2,553	$ 3,854	$ 1,301	50.98%
37	Total Other Public Authority:	$ 820,854	$ 1,243,160	$ 422,306	51.45%
38					
39	14.01 Water Heating - Controlled Service (Rate 191)	$ 688,841	$ 995,327	$ 306,486	44.49%
46	14.06 Controlled Service - Deferred Load Rider (Rates 197, 195, 883)	$ 601,122	$ 664,395	$ 63,273	10.53%
40	Total Water Heating:	$ 1,289,964	$ 1,659,722	$ 369,759	28.66%
41					
42	14.04 Controlled Service - Interruptible Load Rider CT Metering (Rates 170, 165, 881, 168, 268, 169, 269)	$ 1,154,187	$ 1,528,164	$ 373,977	32.40%
43	14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)	$ 2,851,749	$ 3,775,768	$ 924,019	32.40%
44	Total Interruptible:	$ 4,005,936	$ 5,303,932	$ 1,297,996	32.40%
45					
47	14.07 Fixed Time of Service Rider - Self-Contained Metering (Rates 301, 884)	$ 164,901	$ 185,740	$ 20,839	12.64%
48	14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)	$ 114,268	$ 123,667	$ 9,399	8.23%
49	Total Deferred Load:	$ 279,169	$ 309,407	$ 30,239	10.83%
50					
51	TOTAL REVENUE:	$ 114,030,810	$ 159,556,558	$ 45,525,749	39.92%
52					
53					
54	POET Steam Sales moving to EAR from base rates:			$ 231,928	
55	Change in Rider Revenue due to Change in Allocation Factors:			$ 13,754	
56	TOTAL ADDITIONAL REVENUES:			$ 45,771,431	40.14%

Proposed Test Year 2024 Operating Revenue Detailed Comparison - by Rate Schedule and Billing Units

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
1													
2	**9.01 Residential Service (Rate 101)**												
3	Customer Charge	Bills			508,896	$11.00	$11.00	$17.00	$17.00	$ 7,124,541	$ 8,651,232	$ 1,526,688	
4	Seasonal Fixed Charge	Bills			61	$56.00	$56.00	$68.00	$68.00	$ 314	$ 417	$ 74	
5	Energy	kWh	119,796,914	282,520,800	402,317,714	$0.08050	$0.05446	$0.07911	$0.08980	$ 25,029,734	$ 34,847,942	$ 9,818,208	
6	Facilities Charge	Bills			508,896	$0.00	$0.00	$3.50	$3.50		$ 1,781,136	$ 1,781,136	
7	Revenue Adjustment									$ (1,137)		$ 1,137	
8	Base Revenue									$ 32,153,465	$ 45,280,727	$ 13,127,262	
9	Water Heating Control Credit 14.01 (Rate 192)	Bills			3,416	-$8.00	-$8.00	-$8.00	-$8.00	$ (27,326)	$ (27,326)	$ -	
10	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			2,139	-$8.25		-$8.00	-$8.00	$ (17,651)	$ (17,651)	$ -	
11	TailWinds Program 14.09	kWh			2,018	$3.73	$3.73	$3.73	$3.73	$ 7,643	$ 7,643	$ -	
12	WAPA Bill Credit 14.10									$ (69,391)	$ (69,391)	$ -	
13	WAPA, A/C, W/H, & Tailwinds									$ (106,726)	$ (106,726)	$ -	
14													
15	**9.02 Residential Demand Control (Rate 241)**												
16	Customer Charge	Bills			39,268	$20.10	$20.10	$21.00	$21.00	$ 789,287	$ 821,628	$ 35,341	
17	Facilities Charge	Bills			39,268	$0.00	$0.00	$7.00	$7.00	$ -	$ 271,876	$ 274,876	
18	Energy - All kWh	kWh	13,881,352	63,418,529	77,299,881	$0.03379	$0.03161	$0.07911	$0.05519	$ 2,663,966	$ 1,598,101	$ 1,934,135	
19	All kW, ratcheted	kW	50,835	115,080	165,915	$8.00	$8.00	$0.00	$11.00	$ 1,327,319	$ 1,265,881	$ (61,139)	
20	Revenue Adjustment												
21	Base Revenue									$ [illegible]	$ [illegible]	$ 2,182,914	
22	**Adjustments for Riders included in Base Rates**												
23	Renewable Resource Recovery Rider with CWIP Adjustment									$ 2,312,157	$ (3,096,518)	$ (5,108,974)	
24	Transmission Cost Recovery Rider with CWIP Adjustment									$ 2,796,469	$ 1,577,539	$ (1,218,930)	
25	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 1,229,408	$ 1,027,069	$ (202,339)	
26	Generation Cost Recovery Rider									$ 1,164,625	$ -	$ (1,164,625)	
27	Energy Adjustment Rider									$ 13,137,895	$ 13,833,413	$ 695,518	
28	PTC GAAP Provision									$ 1,355,886	$ 1,681,418	$ 325,532	
29	**Total Adjustments:**									$ 21,996,710.17	$ 15,022,952	$ (6,973,789)	
30													
31	**Total Base Revenue for the COSS Class:**									$ 36,934,037	$ 52,137,488	$ 15,203,451	41.2%
32	**Total Adjustments for the COSS Class:**									$ 21,996,740	$ 15,022,952	$ (6,973,789)	31.7%
33	**Total for the COSS Class:**									$ 58,824,052	$ 67,053,713	$ 8,229,662	14.0%
34												0	
35	**9.03 Farm Service (Rate 361)**												
36	Customer Charge	Bills			11,015	$17.40	$17.40	$22.00	$22.00	$ 191,661	$ 242,330	$ 50,669	
37	Energy	kWh	7,298,479	21,730,504	29,028,983	$0.06793	$0.04595	$0.06527	$0.07409	$ 1,494,386	$ 2,086,311	$ 591,926	
38	Single Phase Facilities Charge	Bills			7,556	$10.00	$10.00	$20.00	$20.00	$ 75,563	$ 151,126	$ 75,563	
39	All Three Phase Facilities	Bills			3,459	$20.00	$20.00	$40.00	$40.00	$ 69,174	$ 138,348	$ 69,174	
40	Revenue Adjustment											$ -	
41	Base Revenue									$ 1,830,784	$ 2,618,115	$ 787,332	
42	Water Heating Control Credit 14.01 (Rate 192)	Bills			12	-$8.00	-$8.00	-$8.00	-$8.00	$ (110)	$ (110)	$ 110	
43	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			11	-$8.25		-$8.00		$ (146)	$ (146)	$ 146	
44	TailWinds Program 14.09									$ 269	$ 269	$ 269	
45	WAPA, A/C, W/H, & Tailwinds									$ 13	$ 13	$ -	
46	**Adjustments for Riders included in Base Rates**												
47	Renewable Resource Recovery Rider with CWIP Adjustment									$ 114,626	$ (153,376)	$ (268,002)	
48	Transmission Cost Recovery Rider with CWIP Adjustment									$ 169,257	$ 95,481	$ (73,776)	
49	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 53,237	$ 44,475	$ (8,762)	
50	Generation Cost Recovery Rider									$ 57,729	$ -	$ (57,729)	
51	Energy Adjustment Rider									$ 740,992	$ 771,233	$ 30,241	
52	PTC GAAP Provision									$ 67,210	$ 83,284	$ 16,074	
53	**Total Adjustments:**									$ 1,203,050	$ 841,096	$ (361,953)	
54													
55	**Total Base Revenue for the COSS Class:**									$ 1,830,784	$ 2,618,128	$ 787,344	43.01%
56	**Total Adjustments for the COSS Class:**									$ 1,203,050	$ 841,096	$ (361,954)	-30.09%
57	**Total for the COSS Class:**									$ 3,033,846	$ 3,459,236	$ 425,390	14.02%
58													
59													
60	**10.01 Small General Service - Under 20 kW - Metered Service Secondary (Rate 404)**												
61	Customer Charge	Bills			106,726	$24.90	$24.90	$24.90	$24.90	$ 2,657,177	$ 2,657,177	$ -	
62	Energy	kWh	29,929,362	69,073,530	99,002,892	$0.06682	$0.01521	$0.07239	$0.08218	$ 5,122,480	$ 7,842,816	$ 2,720,366	
63	Facilities Charge	Bills			106,726	$0.00	$0.00	$12.00	$12.00		$ 1,280,712	$ 1,280,712	
64	Revenue Adjustment											$ -	
65	Base Revenue									$ 7,779,957	$ 11,781,035	$ 4,001,078	
66	Water Heating Control Credit 14.01 (Rate 192)	Bills			277	-$8.00	-$8.00	-$8.00	-$8.00	$ (2,213)	$ (2,213)	$ -	
67	WAPA Bill Credit 14.10									$ (194,936)	$ (194,936)	$ -	
68	TailWinds Program 14.09				695	$3.73	$3.73	$3.73	$3.73	$ 2,596	$ 2,596	$ -	
69													
70	WAPA, A/C, W/H, & Tailwinds									$ (194,552)	$ (194,552)	$ -	
71													

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
72	**10.01 Small General Service - Under 20 kW - Metered Service Primary (Rate 405)**												
73	Customer Charge	Bills			45	$24.90	$24.90	$24.90	$24.90	$ 1,121	$ 1,121	$ -	
74	Energy	kWh	1,027	1,904	2,931	$0.06440	$0.04331	$0.07037	$0.08048	$ 149	$ 225	$ 77	
75	Facilities Charge	Bills			45	$0.00	$0.00	$12.00	$12.00	$ -	$ 540	$ 540	
76	Revenue Adjustment									$ (0)		$ 0	
77	Base Revenue									1,269	1,886	$ 617	
78													
79	**10.01 Small General Service Non metered Service 1000 Watts or less Rate**												
80	Energy	kWh			5,632	[illegible]	$0.06681	$0.06681	$0.06681	$ 376	$ -		
81													
82	**10.02 General Service 20 kW or Greater Secondary Service (Rate 401)**												
83	Customer Charge	Bills			29,866	$31.90	$31.90	$54.00	$54.00	$ 952,725	$ 1,612,761	$ 660,039	
84	Energy	kWh	76,950,978	206,163,600	283,114,578	$0.07506	$0.05078	$0.05346	$0.06032	$ 16,259,127	$ 16,568,091	$ 308,967	
85	Demand per kW	kW	125,756	963,873	1,389,629	$0.00	$0.00	$2.21	$2.75	$ -	$ 3,601,341	$ 3,601,341	
86	Facilities Charge	kW			2,356,992	$0.98	$0.98	$2.12	$2.12	$ 2,303,819	$ 5,008,137	$ 2,701,288	
87	Revenue Adjustment									$ 6,118		$ (6,118)	
88	Base Revenue									19,521,819	$ 26,793,339	1	
89													
90	**10.02 General Service - 20 kW or Greater - Primary Service (Rate 403)**												
91	Customer Charge	Bills			72	$21.30	$21.30	$36.00	$36.00	$ 1,534	$ 2,592	$ 1,058	
92	Energy	kWh	272,272	680,225	952,497	$0.07233	$0.04865	$0.05216	$0.05852	$ 52,786	$ 54,009	$ 1,223	
93	Demand per kW	kW	823	1,772	2,595	$0.00	$0.00	$2.15	$2.62	$ -	$ 6,411	$ 6,411	
94	Facilities Charge	kW			4,340	$0.65	$0.65	$1.42	$1.42	$ 2,842	$ 6,178	$ 3,336	
95	Revenue Adjustment									$ (21)		$ 21	
96	Base Revenue									57,111	69,191	$ 12,051	
97													
98	**10.03 General Service Time of Use (Commercial TOU) (Rates 708, 709, 710)**												
99	Customer Charge	Bills			12	$219.00	$219.00	$219.00	$219.00	$ 2,628	$ 2,628	$ -	
100	Energy - Declared-Peak	kWh	299	181	780	$0.43261	$0.16259	$0.19539	$0.23215	$ 208	$ 31	$ (177)	
101	Energy - Intermediate	kWh	16,293	30,101	16,391	$0.02571	$0.02638	$0.03911	$0.03959	$ 1,213	$ 1,831	$ 621	
102	Energy - Off-Peak	kWh	11,211	21,066	32,310	$0.01702	$0.01845	$0.02573	$0.03407	$ 550	$ 1,007	$ 127	
103	Demand per kW - Declared-Peak	kW	-	-	-	N/A	N/A	N/A	N/A			$ -	
104	Demand per kW - Intermediate	kW	[illegible]	[illegible]	269	$3.44	$5.12	$2.57	$6.18	$ 1,229	$ 1,344	$ 115	
105	Demand per kW - Off-Peak	kW	-	-	-	$0.00	$0.00	$0.00	$0.00	$ -		$ -	
106	Facilities Charge	kW	263	542	805	$0.98	$0.98	$2.12	$2.12	$ 787	$ 1,711	$ 924	
107	Revenue Adjustment									$ (441)		$ 441	
108	Base Revenue									6,204	8,555	$ 2,351	
109	**Adjustments for Riders Included in Base Rates**												
110	Renewable Resource Recovery Rider with CWIP Adjustment									$ 1,713,445	$ (2,275,117)	$ (3,988,562)	
111	Transmission Cost Recovery Rider with CWIP Adjustment									$ 2,235,799	$ 1,261,255	$ (974,544)	
112	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 1,075,014	$ 898,086	$ (176,928)	
113	Generation Cost Recovery Rider									$ 862,945	$ -	$ (862,945)	
114	Energy Adjustment Rider									$ 10,328,623	$ 10,797,195	$ 168,572	
115	PTC GAAP Provision									$ 1,001,662	$ 1,235,395	$ [illegible]	
116	**Total Adjustments:**									$ [illegible]	$ [illegible]	$ [illegible]	
117													
118	**Total Base Revenue for the COSS Class:**									**$ 27,366,763**	**$ 38,459,455**	**$ 11,092,692**	**40.53%**
119	**Total Adjustments for the COSS Class:**									**$ 17,220,488**	**$ 11,916,813**	**$ (5,303,675)**	**30.80%**
120	**Total for the COSS Class:**									**$ 44,392,699**	**$ 50,181,716**	**$ 5,789,017**	**13.04%**
121													
122												$ -	
123	**10.04 Large General Service - Secondary Service (Rate 603)**												
124	Customer Charge	Bills			3,081	$215.90	$215.90	$215.90	$215.90	$ 665,188	$ 665,188	$ -	
125	Energy -All kWh	kWh	125,951,771	241,160,691	367,112,462	$0.02286	$0.02341	$0.03487	$0.04190	$ 8,525,572	$ 14,496,790	$ 5,971,218	
126	Demand per kW	kW	282,067	555,250	837,317	$10.75	$8.54	$11.78	$12.28	$ 7,774,050	$ 10,143,303	$ 2,369,253	
127	Facilities Charge < 1,000 kW	kW	216,387	438,661	655,048	$0.76	$0.76	$0.75	$0.75	$ 495,198	$ 489,790	$ (5,407)	
128	Facilities Charge > 1,000 kW	kW	113,328	222,731	336,059	$0.56	$0.56	$0.52	$0.52	$ 189,305	$ 176,365	$ (12,940)	
129	Revenue Adjustment									$ [illegible]		$ [illegible]	
130	Base Revenue									[illegible]	$ 25,971,436	$ [illegible]	
131													
132	Air Conditioning Control Rider 14.08 (Rate 760)	Bills			12	-$8.25	-$8.25	-$8.00	-$8.00	$ (99)	$ (99)	$ -	
133	TailWinds Program 14.09				230	$3.73	[illegible]	$3.73	$3.73	$ 858	$ 858	$ -	
134	WAPA Bill Credit 14.10									$ [illegible]	$ [illegible]	$ -	
135	WAPA A/C, W/H, & Tailwinds									$ [illegible]	$ [illegible]	$ -	
136													
137	**10.04 Large General Service - Primary Service (Rate 602)**												
138	Customer Charge	Bills			105	$282.00	$282.00	$282.00	$282.00	$ 29,610	$ 29,610	$ -	
139	Energy -All kWh	kWh	52,139,517	95,669,781	117,809,298	$0.02221	$0.02261	$0.03103	$0.01062	$ 3,325,547	$ 5,660,724	$ 2,335,178	
140	Demand per kW	kW	95,683	[illegible]	270,195	$10.35	$8.15	$11.29	$11.69	$ 2,412,595	$ 3,120,939	$ [illegible]	
141	Facilities Charge - All kW	kW	109,652	179,172	288,823	$0.48	$0.48	$0.52	$0.52	$ 138,635	$ 151,576	$ 12,940	
142	Revenue Adjustment									$ 21,361		$ [illegible]	
143	Base Revenue									$ [illegible]	$ [illegible]	$ [illegible]	
144													
145	**11.01 Standby Service Option A: Firm Transmission Service (Rates 941, 942, 943)**												

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
146	Customer Charge	Bills			12	$282.08	$282.08	$282.08	$282.08	$ 3,385	$ 3,385	$ -	
147	Facilities Charge per month per kW of Backup	kW			-	N/A	N/A	N/A	N/A	$ -		$ -	
148	Reservation Charge per kW of Contracted Backup	kW	1,800	3,600	5,400	$0.86830	$0.09424	$1.38999	$0.46669	$ 1,902	$ 4,182	$ 2,280	
149	Metered Demand per day per kW On-Peak Backup	kW	1,265	3,532	4,797	$0.43199	$0.29380	$0.49600	$0.17900	$ 1,584	$ 1,260	$ (324)	
150	Energy - On-Peak	kWh	10,685	24,130	34,815	$0.03213	$0.02775	$0.05568	$0.04935	$ 1,013	$ 1,786	$ 773	
151	Energy - Mid-Peak	kWh	20,331	25,531	45,862	$0.02465	$0.02494	$0.04552	$0.04518	$ 1,138	$ 2,079	$ 941	
152	Energy - Off-Peak	kWh	20,920	40,685	61,605	$0.01653	$0.01760	$0.02978	$0.03897	$ 1,062	$ 2,208	$ 1,147	
153	Revenue Adjustment				-					$ (67)		$ 67	
154	Base Revenue									$ 10,017.00	$ 11,899.77	$ 1,882.77	
155													
156	**14.02 Real Time Pricing Primary Service (Rate 662)**												
157	Customer Charge	Bills			12	$282.00	$282.00	$282.00	$282.00	$ 3,381	$ 3,381	$ -	
158	Energy - All kWh	kWh	12,179,176	31,691,222	43,870,398	Real Time Pricing		Real Time Pricing		$ 1,922,204	$ 1,922,204	$ -	
159	Base Revenue									$ 1,925,588	$ 1,925,588	$ -	
160													
161	**10.04 Large General Service - Transmission Service (Rate 632)**												
162	Customer Charge	Bills			-	$282.00	$282.00	$282.00	$282.00	$ -		$ -	
163	Energy - All kWh	kWh			-	$0.02103	$0.02121	$0.03323	$0.03943	$ -		$ -	
164	Demand per kW	kW			-	$8.85	$7.30	$10.46	$5.76	$ -		$ -	
165	Facilities Charge	kW			-	N/A	N/A	N/A	N/A	$ -		$ -	
166	**Total Base Revenue:**									$ -		$ -	
167	**[PROTECTED DATA BEGINS...**												
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Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
220										$ 13,502,040	$ 18,105,026	$ 4,602,986	
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234	**11.01 Standby Service Option A: Firm Secondary Service (Rates 947, 948, 949)**												
235	Customer Charge	Bills			-	$242.24	$242.24	$215.90	$215.90				
236	Facilities Charge per month per kW of Contracted Backup	kW			-	$0.55	$0.55	$0.55	$0.55				
237	Reservation Charge per kW of Contracted Backup	kW			-	$0.97571	$0.10590	$1.60890	$1.26909				
238	Metered Demand per day per kW On-Peak Backup	kW			-	$0.57423	$0.41361	$0.60611	$0.45409				
239	Energy - On-Peak	kWh			-	$0.03527	$0.03090	$0.05867	$0.05264				
240	Energy - Mid-Peak	kWh			-	$0.02683	$0.02753	$0.04780	$0.04799				
241	Energy - Off-Peak	kWh			-	$0.01776	$0.01925	$0.03119	$0.04129				
242													
243	**11.01 Standby Service - Option A: Firm - Primary Service (Rates 944, 945, 946)**												
244	Customer Charge	Bills			-	$282.08	$282.08	$282.08	$282.08				
245	Facilities Charge per month per kW of Backup	kW			-	$0.45	$0.45	$0.45	$0.45				
246	Reservation Charge per kW of Contracted Backup	kW			-	$0.93395	$0.10136	$1.50014	$1.19059				
247	Metered Demand per day per kW On-Peak Backup	kW			-	$0.51988	$0.39227	$0.58599	$0.43391				
248	Energy - On-Peak	kWh			-	$0.03122	$0.02981	$0.05711	$0.05093				
249	Energy - Mid-Peak	kWh			-	$0.02612	$0.02665	$0.01663	$0.01653				
250	Energy - Off-Peak	kWh			-	$0.01738	$0.01871	$0.03018	$0.04010				
251													
252	**11.01 Standby Service - Option A: Firm - Transmission Service (Rates 941, 942, 943)**												
253	Customer Charge	Bills				$282.08	$282.08	$282.08	$282.08				
254	Facilities Charge per month per kW of Backup	kW				N/A	N/A	N/A	N/A				
255	Reservation Charge per kW of Contracted Backup	kW				$0.86830	$0.09424	$1.39874	$0.57174				
256	Metered Demand per day per kW On-Peak Backup	kW				$0.43199	$0.29380	$0.49600	$0.17900				
257	Energy - On-Peak	kWh				$0.03213	$0.02775	$0.05568	$0.04935				
258	Energy - Mid-Peak	kWh				$0.02465	$0.02494	$0.04552	$0.04518				
259	Energy - Off-Peak	kWh				$0.01653	$0.01760	$0.02978	$0.03897				
260													
261	**11.01 Standby Service - Option B: Non-Firm - Secondary Service (Rates 956, 957, 958)**												
262	Customer Charge	Bills			-	$212.21	$212.24	$215.90	$215.90				
263	Facilities Charge per month per kW of Backup	kW			-	$0.55	$0.55	$0.55	$0.55				
264	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A				
265	Energy - Mid-Peak	kWh			-	$0.02683	$0.02753	$0.04780	$0.01799				
266	Energy - Off-Peak	kWh			-	$0.01776	$0.01925	$0.03119	$0.01129				
267													
268	**11.01 Standby Service Option B: Non Firm Primary Service (Rates 953, 954, 955)**												
269	Customer Charge	Bills			-	$282.08	$282.08	$282.08	$282.08				
270	Facilities Charge per month per kW of Backup	kW			-	$0.45	$0.45	$0.45	$0.45				
271	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A				
272	Energy - Mid-Peak	kWh			-	$0.02612	$0.02665	$0.04663	$0.04653				
273	Energy - Off-Peak	kWh			-	$0.01738	$0.01871	$0.03048	$0.04010				
274													
275	**11.01 Standby Service - Option B: Non-Firm - Transmission Service (Rates 950, 951, 952)**												
276	Customer Charge	Bills			-	$282.08	$282.08	$282.08	$282.08				
277	Facilities Charge per month per kW of Backup	kW			-	N/A	N/A	N/A	N/A				
278	Energy - On-Peak	kWh			-	N/A	N/A	N/A	N/A				
279	Energy - Mid-Peak	kWh			-	$0.02465	$0.02491	$0.01552	$0.04518				
280	Energy - Off-Peak	kWh			-	$0.01653	$0.01760	$0.02978	$0.03897				
281													
282	**11.02 Irrigation Service - Option 1: Non-Time-of-Use (Rate 703)**												
283	Customer Charge	Bills			57	$24.30	$24.30	$24.30	$24.30	$ 1,385	$ 1,385	$ -	
284	Energy	kWh	406,319	49,765	456,084	$0.04533	$0.02633	$0.06624	$0.04724	$ 19,730	$ 29,264	$ 9,534	
285	18% Return of Distribution Facilities				-					$ 5,158	$ 5,158	$ -	
286	Revenue Adjustment											$ -	
287	Base Revenue									26,273	$ 35,807	$ 9,534	
288			-										
289	**11.02 Irrigation Service Option 2 (Rates 704, 705, 706)**												
290	Customer Charge	Bills			130	$24.30	$24.30	$24.30	$24.30	$ 3,159	$ 3,159	$ -	
291	Energy - Declared-Peak	kWh	12,789	290	13,079	$0.17685	$0.12867	$0.18683	$0.22632	$ 2,299	$ 808	$ (1,191)	
292	Energy - Intermediate	kWh	360,088	29,110	389,198	$0.03274	$0.03050	$0.06171	$0.06509	$ 12,686	$ 24,145	$ 11,459	
293	Energy - Off-Peak	kWh	150,273	35,640	185,913	$0.01120	$0.01157	$0.03369	$0.01718	$ 6,913	$ 16,861	$ 9,919	

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
294	Demand per kW - Declared-Peak	kW	-	-	-	$0.00	$0.00	$0.00	$0.00	$ -	$ -	$ -	
295	Demand per kW - Intermediate	kW	-	-	-	$0.00	$0.00	$0.00	$0.00	$ -	$ -	$ -	
296	Demand per kW - Off-Peak	kW	-	-	-	$0.00	$0.00	$0.00	$0.00	$ -	$ -	$ -	
297	10% Return of Distribution Facilities				-					$ 5,196	$ 5,196	$ -	
298	Revenue Adjustment											$ -	
299	Base Revenue									30,252	50,170	$ 20,972	
300	**Adjustments for Riders included in Base Rates**												
301	Renewable Resource Recovery Rider with CWIP Adjustment									$ 3,539	$ (1,762)	$ (8,301)	
302	Transmission Cost Recovery Rider with CWIP Adjustment									$ 7,840	$ 1,423	$ (5,417)	
303	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 6,248	$ 5,220	$ (1,028)	
304	Generation Cost Recovery Rider									$ 1,782	$ -	$ (1,782)	
305	Energy Adjustment Rider									$ 30,398	$ 30,776	$ 377	
306	PTC GAAP Provision									$ 2,075	$ 2,586	$ 511	
307	**Total Adjustments:**									$ 51,883	$ 38,212	$ (13,641)	
308													
309	**Total Base Revenue for the COSS Class:**									$ 56,525	$ 85,977	$ 29,452	52.10%
310	**Total Adjustments for the COSS Class:**									$ 51,883	$ 38,242	$ (13,641)	-26.29%
311	**Total for the COSS Class:**									$ 108,408	$ 124,219	$ 15,811	14.58%
312													
313	**11.03 Outdoor Lighting - Metered - Energy Only (Rate 748)**									$ 81,565			
314	Customer Charge	Bills			1,478	$2.00	$2.00	$2.00	$2.00	$ 2,955	$ 2,955	$ (2,955)	
315	Energy	kWh			1,220,905	$0.06681	$0.06681	$0.08437	$0.08437	$ 92,978	$ 103,012	$ (92,978)	
316													
317	Base Revenue									$ 95,933	$ 105,968	$ 10,035	10.46%
318													
319	**11.03 Outdoor Lighting Non Metered Energy Only (Rate 749)**												
320		kWh			1,190,812	$0.00	$0.00	$0.00	$0.00	$ -	$ -		
321	Monthly charge for connected KW	kW			1,253 $	22.83 $	22.83	$25.21	$25.21	$ 97,067	$ 107,220	$ (97,067)	
322													
323	Base Revenue:									$ 97,067	$ 107,220	$ (97,067)	-100.00%
324													
325	**11.03 Sign Lighting (Rate 744)**												
326	Monthly charge for connected KW	kW			1,831	$22.83	$22.83	$25.21	$25.21	$ 41,803	$ 46,176	$ 4,373	
327	Energy	kWh			150,773					$ -	$ -	$ -	
328	Base Revenue									41,803	46,176	$ 4,373	10.46%
329													
330	**11.04 Outdoor Lighting - Street & Area Lighting (Rate 741)**												
331	Type		kWh/lt	Annual Kwh	Quantity			Percent Increase	11.44%				
332	MV-6	Lts	70		45,672	$7.12	$7.12	$7.94	$7.94	$ 325,265	$ 362,478		
333	MV-6PT	Lts	70		824	$10.16	$10.16	$11.32	$11.32	$ 8,371	$ 9,329		
334	MV-11	Lts	100		59	$12.90	$12.90	$14.38	$14.38	$ 761	$ 848		
335	MV-21	Lts	154		244	$16.99	$16.99	$18.93	$18.93	$ 4,145	$ 4,619		
336	MV-35	Lts	260	-		$21.92	$21.92	$27.77	$27.77	$ -	$ -		
337	MV-55	Lts	366	-		$31.86	$31.86	$35.50	$35.50	$ -	$ -		
338	MA-8	Lts	41		838	$8.59	$8.59	$9.58	$9.58	$ 7,202	$ 8,027		
339	MA-14	Lts	70		12	$16.36	$16.36	$18.23	$18.23	$ 196	$ 219		
340	MA-20	Lts	98	-		$18.67	$18.67	$20.81	$20.81	$ -	$ -		
341	MA-36	Lts	156		180	$18.29	$18.29	$20.38	$20.38	$ 3,292	$ 3,668		
342	MA-110	Lts	369		180	$39.02	$39.02	$43.49	$43.49	$ 7,024	$ 7,828		
343	HPS-9	Lts	44		27,229	$7.64	$7.64	$8.51	$8.51	$ 208,026	$ 231,826		
344	HPS-9PT	Lts	44		2,028	$9.87	$9.87	$11.00	$11.00	$ 20,026	$ 22,318		
345	HPS-14	Lts	64		1,171	$11.90	$11.90	$13.26	$13.26	$ 13,931	$ 15,525		
346	HPS-14PT	Lts	64		996	$12.73	$12.73	$14.19	$14.19	$ 12,679	$ 14,129		
347	HPS-19	Lts	83		154	$13.83	$13.83	$15.41	$15.41	$ 2,129	$ 2,373		
348	HPS-23	Lts	102		2,167	$15.65	$15.65	$17.44	$17.44	$ 33,904	$ 37,783		
349	HPS-44	Lts	156		1,576	$19.31	$19.31	$21.52	$21.52	$ 30,437	$ 33,920		
350	UHPS23	Lts	102		12	$18.11	$18.11	$20.18	$20.18	$ 217	$ 242		
351	UMV6	Lts	70		48	$9.58	$9.58	$10.68	$10.68	$ 460	$ 513		
352	**Seasonal Charge**				92	$32.79	$32.79	$36.55	$36.55	$ 3,017	$ 3,362		
353	**11.04 Outdoor Lighting Flood Lighting (Rate 743)**												
354	Type		kWh/lt	Annual Kwh	Quantity								
355	400MV-F	Lts	154		721	$17.35	$17.35	$19.33	$19.33	$ 12,509	$ 13,941		
356	400MA-F	Lts	156		1,883	$18.78	$18.78	$20.93	$20.93	$ 35,363	$ 39,409		
357	400HPS-F	Lts	156		4,680	$19.20	$19.20	$21.40	$21.40	$ 89,856	$ 100,136		
358	1000MV-F	Lts	366	-		$30.93	$30.93	$34.47	$34.47	$ -	$ -		
359	1000MA-F	Lts	308		1,883	$32.62	$32.62	$36.35	$36.35	$ 61,423	$ 68,451		
360	UNDERGROUND SERVICE:					$2.16	$2.16	$2.71	$2.74	$ -	$ -		
361	Revenue Adjustment									$ 20,218			
362	Base Revenue			8,237,849						900,153	$ 980,941	$ [illegible]	
363													
364	**11.07 LED STREET and AREA LIGHTING DUSK TO DAWN**			Future kWh Allocation									
365	Type		kWh/lt	Annual Kwh	Quantity			Percent Increase	11.44%				
366	**LED5**	Lts	16		116,839	$7.44	$7.44	$8.29	$8.29	$ 869,282	$ 968,735		

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
367	LED8	Lts	26		1046	$13.88	$13.88	$15.47	$15.47	$ 14,518	$ 16,180		
368	LED3PT	Lts	9		2536	$10.01	$10.01	$11.16	$11.16	$ 25,385	$ 28,290		
369	LED5PT	Lts	16		1608	$12.75	$12.75	$14.21	$14.21	$ 20,502	$ 22,848		
370	LED10	Lts	32		6184	$15.71	$15.71	$17.51	$17.51	$ 97,151	$ 108,265		
371	LED13	Lts	45		3441	$20.66	$20.66	$23.02	$23.02	$ 71,091	$ 79,224		
372	LED20 - Flood	Lts	68		13,493	$18.98	$18.98	$21.15	$21.15	$ 256,097	$ 285,397		
373	LED30 - Flood	Lts	89		3337	$30.96	$30.96	$34.50	$34.50	$ 103,314	$ 115,133		
374										$ 101,198			
375				2,025,558	-	$0.00	$0.00			[illegible]	1,624,072	$ 66,018	
376													
377	PLED5	Lts	16			$6.95	$6.95	$7.75	$7.75				
378	PLED8	Lts	26			$13.08	$13.08	$14.58	$14.58				
379	PLED3PT	Lts	9			$9.71	$9.71	$10.85	$10.85				
380	PLED5PT	Lts	16			$12.26	$12.26	$13.66	$13.66				
381	PLED10	Lts	32			$14.71	$14.71	$16.39	$16.39				
382	PLED13	Lts	45			$19.26	$19.26	$21.46	$21.46				
383	PLED20 Flood	Lts	68			$16.89	$16.89	$18.82	$18.82				
384	PLED30 Flood	Lts	89			$28.21	$28.21	$31.11	$31.11				
385													
386	Seasonal Charge					$32.79	$32.79	$36.55	$36.55				
387	UNDERGROUND SERVICE:					$2.46	$2.46	$2.74	$2.74				
388	UNDERGROUND SERVICE SUPPLIED BY THE COMPANYover 200Ft					$0.11	$0.11	$0.12	$0.12				
389													
390	ALUMINUM ALLOY POLES, Additional Monthly Charge												
391	STANDARDS 30'	ea				$11.67	$11.67	$26.61	$26.61				
392	STANDARDS 40'	ea				$10.87	$10.87	$27.94	$27.94				
393													
394	LED FLOOD VISOR, Additional Monthly Charge												
395	Lighting Visor LED 20-Flood	ea				$0.76	$0.76	$0.85	$0.85				
396	Lighting Visor LED 30-Flood	ea				$1.38	$1.38	$1.54	$1.54				
397													
398	DECORATIVE LIGHTS		Appx Wattage										
399	DLEDA7 (Arlington)	Lts	66			$87.77	$87.77	$97.81	$97.81				
400	DLEDG7 (Granville)	Lts	68			$86.11	$86.11	$95.96	$95.96				
401	DLEDE17 (Esplanade)	Lts	170			$110.56	$110.56	$123.21	$123.21				
402	Lighting & Irrigation RevenueCorrections									$ (100,737)			
403	Adjustments for Riders included in Base Rates												
404	Renewable Resource Recovery Rider with CWIP Adjustment	kWh								$ 162,353	$ (182,252)	$ (344,604)	
405	Transmission Cost Recovery Rider with CWIP Adjustment	%								$ 74,484	$ 19,224	$ (55,260)	
406	Advanced Meter & Distribution Technology Rider with CWIP adjustm	kWh								$ 377,958	$ 315,753	$ (62,205)	
407	Generation Cost Recovery Rider	kWh								$ 81,766	$ -	$ (81,766)	
408	Energy Adjustment Rider	kWh								$ 262,779	$ 307,739	$ 44,960	
409	PTC GAAP Provision									$ 95,191	$ 98,963	$ 3,769	
410	Total Adjustments:									$ 1,051,537	$ 559,427	$ (495,106)	
411													
412	Total Base Revenue for the COSS Class:							$ 2,864,376.55	$ 2,864,376.55	$ 2,593,058	$ 2,864,377	$ 271,319	10.46%
413	Total Adjustments for the COSS Class:									$ 1,054,534	$ 559,428	$ (495,106)	-46.95%
414	Total for the COSS Class:									$ 3,647,592	$ 3,423,805	$ (223,787)	6.14%
415													
416	11.05 Municipal Pumping - Secondary Service (Rate 872)												
417	Customer Charge	Bills			6,441	$26.50	$26.50	$33.45	$33.45	$ 170,687	$ 215,451	$ 44,765	
418	Facilities Charge (Changing per Month to per KW)	kW			80,026	$0.65	$0.65	$2.12	$2.12	$ 52,017	$ 169,655	$ 117,638	
419	Energy - All kWh	kWh	6,177,157	11,768,013	17,945,170	$0.04599	$0.03111	$0.04373	$0.04963	$ 650,190	$ 854,200	$ 204,010	
420	Revenue Adjustment									$ (54,592)		$ 54,592	
421	Base Revenue									818,301	1,239,306	$ 421,005	
422													
423	11.05 Municipal Pumping Primary Service (Rate 874)												
424	Customer Charge	Bills			-	$26.50	$26.50	$33.15	$33.15	$ -		$ -	
425	Facilities Charge (Changing per Month to per KW)	KW			-	$0.65	$0.65	$1.12	$1.12	$ -		$ -	
426	Energy - All kWh	kWh			-	$0.01132	$0.02981	$0.01250	$0.01861	$ -		$ -	
427	Base Revenue									$ -		$ -	
428													
429	11.06 Civil Defense - Fire Sirens (Rate 843)												
430	Customer Charge	Bills			624	$1.22	$1.22	$1.22	$1.22	$ 761	$ 761	$ -	
431	Load Charge	HP			4,170	$0.42962	$0.42962	$0.74170	$0.74170	$ 1,792	$ 3,093	$ 1,301	
432	Base Revenue									2,553	3,854	$ 1,301	
433	Adjustments for Riders included in Base Rates												
434	Renewable Resource Recovery Rider with CWIP Adjustment									$ 51,394	$ (69,288)	$ (120,682)	
435	Transmission Cost Recovery Rider with CWIP Adjustment									$ 104,632	$ 59,025	$ (45,607)	
436	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 36,248	$ 30,282	$ (5,966)	
437	Generation Cost Recovery Rider									$ 25,884	$ -	$ (25,884)	
438	Energy Adjustment Rider									$ 171,092	$ 183,367	$ 9,275	
439	PTC GAAP Provision									$ 30,134	$ 37,624	$ 7,489	
440	Total Adjustments:									$ 722,354	$ 541,010	$ (181,374)	

Line No.	Charge	Units	Billing Units Summer	Billing Units Winter	Billing Units Annual	Present Rate Summer	Present Rate Winter	Proposed Rate Summer	Proposed Rate Winter	Present Operating Revenues Annual	Proposed Operating Revenues Annual	Increase Annual	Pct Inc. Annual
441													
442	**Total Base Revenue for the COSS Class:**									$ 820,854	$ 1,243,160	$ 422,306	51.45%
443	**Total Adjustments for the COSS Class:**									$ 722,384	$ 541,010	$ (181,374)	-25.11%
444	**Total for the COSS Class:**									$ 1,543,238	$ 1,784,170	$ 240,932	15.61%
445													
446	**14.01 Water Heating - Controlled Service (Rate 191)**												
447	Customer Charge	Bills			59,233	$4.00	$4.00	$5.00	$5.00	$ 236,932	$ 296,165	$ 59,233	
448	Facilities Charges per Month	Bills			59,233	$2.00	$2.00	$2.00	$2.00	$ 118,166	$ 118,166	$ -	
449	Energy - All kWh	kWh	3,376,056	8,626,096	12,002,152	$0.03078	$0.02661	$0.01717	$0.04886	$ 333,113	$ 580,696	$ 247,253	
450	Revenue Adjustment									$ 0		$ (0)	
451	Base Revenue									[illegible]	995,327	$ 306,186	
452													
453	**14.06 Controlled Service Deferred Load Rider (Rates 197, 195, 883)**												
454	Customer Charge	Bills			8,150	$8.80	$8.80	$10.00	$10.00	$ 71,720	$ 81,500	$ 9,780	
455	Facilities Charge	Bills			8,150	$11.60	$11.60	$11.60	$11.60	$ 94,510	$ 94,510	$ -	
456	Energy - All kWh	kWh	1,226,209	16,997,324	18,223,533	$0.02602	$0.02371	$0.03564	$0.02616	$ 434,849	$ 488,355	$ 53,506	
457	Penalty kWh	kWh			-	$0.35916	$0.16537	$0.17726	$0.18221	$ -		$ -	
458	Revenue Adjustment									$ 13		$ (13)	
459	Base Revenue									601,122	664,395	$ 63,273	
460													
461	**Adjustments for Riders Included in Base Rates**												
462	Renewable Resource Recovery Rider with CWIP Adjustment									$ 80,765	$ (93,030)	$ (173,795)	
463	Transmission Cost Recovery Rider with CWIP Adjustment									$ 26,916	$ -	$ (26,916)	
464	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 333,025	$ 278,215	$ (54,810)	
465	Generation Cost Recovery Rider									$ 40,676	$ -	$ (40,676)	
466	Energy Adjustment Rider									$ 860,771	$ 805,545	$ (55,226)	
467	PTC GAAP Provision									$ 47,356	$ 50,516	$ 3,160	
468	**Total Adjustments:**									$ 1,389,510	$ 1,041,246	$ (348,264)	
469													
470	**Total Base Revenue for the COSS Class:**									$ 1,289,964	$ 1,659,723	$ 369,759	28.66%
471	**Total Adjustments for the COSS Class:**									$ 1,389,510	$ 1,041,246	$ (348,264)	-25.06%
472	**Total for the COSS Class:**									$ 2,679,474	$ 2,700,969	$ 21,495	0.80%
473													
474	**14.02 Real Time Pricing Secondary Service (Rate 664)**												
475	Administrative Charge	Bills			-	$282.00	$282.00	$282.00	$282.00				
476	Consumption Change from CBL	kWh			-								
477	Conservation Improvement Program				-								
478													
479	**14.02 Real Time Pricing Primary Service (Rate 662)**												
480	Administrative Charge	Bills			-	$282.00	$282.00	$282.00	$282.00				
481	Consumption Change from CBL	kWh			-								
482	Conservation Improvement Program				-								
483													
484	**14.02 Real Time Pricing - Transmission Service (Rate 660)**												
485	Administrative Charge	Bills			-	$282.00	$282.00	$282.00	$282.00				
486	Consumption Change from CBL	kWh			-								
487	Conservation Improvement Program				-								
488													
489	**14.03 Large General Service Rider**												
490	Administrative Charge	Bills			-	$282.00	$282.00	$282.00	$282.00				
491	Fixed Rate Energy Pricing (FREP) Peak	kWh			-								
492	Fixed Rate Energy Pricing (FREP) Shoulder	kWh			-								
493	Fixed Rate Energy Pricing (FREP) Off-Peak	kWh			-								
494	Capacity Purchase	kW			-								
495													
496	**14.04 Controlled Service Interruptible Load Rider CT Metering Option 1 (Rates 170, 165, 881)**												
497	Customer Charge	Bills			2,619	$20.20	$20.20	$20.20	$20.20	$ 52,908	$ 52,908	$ -	
498	Facilities Charge	kW			558,708	$0.76	$0.76	$1.42	$1.42	$ 424,618	$ 793,365	$ 368,747	
499	Energy - All kWh	kWh	7,784,504	57,052,011	64,836,515	$0.01064	$0.01009	$0.01148	$0.00996	$ 658,207	$ 657,395	$ (812)	
500	Penalty kWh	kWh	69,359	806,935	876,294	$0.41350	$0.14322	$0.18412	$0.20847			$ -	
501	Revenue Adjustment									$ 50		$ (50)	
502	Base Revenue									1,135,765	1,503,669	$ 367,116	
503													
504	**14.04 Controlled Service Interruptible Load Rider CT Metering Option 2 (Rates 168, 268, 169, 269)**												
505	Customer Charge	Bills	40	82	122	$20.20	$20.20	$20.20	$20.20	$ 2,458	$ 2,458	$ -	
506	Facilities Charge	kW			9,301	$0.76	$0.76	$1.42	$1.42	$ 7,069	$ 13,175	$ 6,106	
507	Energy - All kWh	kWh	69,359	806,935	876,294	$0.01064	$0.01009	$0.01148	$0.00996	$ 8,876	$ 8,830	$ (46)	
508	Control Period Demand	kW			-	$11.30	$8.49	$11.78	$12.28	$ -		$ -	
509	Revenue Adjustment									$ 1	$ 32	$ 31	
510	Base Revenue									18,404	24,495	$ 6,091	
511													
512	**14.05 Controlled Service - Interruptible Load Rider Self-Contained Metering (Rates 190, 185, 882)**												
513	Customer Charge	Bills			85,305	$8.50	$8.50	$8.50	$8.50	$ 725,093	$ 725,093	$ -	
514	Facilities Charge	Bills			85,305	$11.70	$11.70	$11.70	$11.70	$ 998,069	$ 998,069	$ -	

Line No.	Charge	Units	Billing Units			Present Rate		Proposed Rate		Present Operating Revenues	Proposed Operating Revenues	Increase Annual	Pct Inc. Annual
			Summer	Winter	Annual	Summer	Winter	Summer	Winter	Annual	Annual		
515	Energy - All kWh	kWh	12,491,661	119,327,289	131,818,950	$0.00911	$0.00850	$0.01770	$0.01535	$ 1,128,706	$ 2,052,607	$ 923,901	
516	Penalty kWh	kWh	-	-	-	$0.41350	$0.17038	$0.18412	$0.20847	$ -		$ -	
517	Revenue Adjustment									$ (118)		$ 118	
518	Base Revenue									2,851,749	3,775,768	$ 924,019	
519	**Adjustments for Riders Included in Base Rates**												
520	Renewable Resource Recovery Rider with CWIP Adjustment									$ 250,813	$ (279,508)	$ (530,321)	
521	Transmission Cost Recovery Rider with CWIP Adjustment									$ 175,904	$ -	$ (175,904)	
522	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 181,981	$ 105,162	$ (79,819)	
523	Generation Cost Recovery Rider									$ 126,317	$ -	$ (126,317)	
524	Energy Adjustment Rider									$ 5,732,433	$ 5,428,166	$ (301,267)	
525	PTC GAAP Provision									$ 147,062	$ 151,774	$ 4,712	
526	**Total Adjustments:**									$ 6,917,512	$ 5,705,594	$ (1,211,917)	
527													
528													
529	**Total Base Revenue for the COSS Class:**									$ 4,005,936	$ 5,303,932	$ 1,297,996	32.40%
530	**Total Adjustments for the COSS Class:**									$ 6,917,512	$ 5,705,594	$ (1,211,917)	17.52%
531	**Total for the COSS Class:**									$ 10,923,448	$ 11,009,526	$ 86,079	0.79%
532													
533	**14.07 Fixed Time of Service Rider Self Contained Metering (Rates 301, 884)**												
534	Customer Charge	Bills			3,120	$6.70	$6.70	$10.00	$10.00	$ 20,905	$ 31,202	$ 10,297	
535	Facilities Charge	Bills			3,120	$6.00	$6.00	$6.00	$6.00	$ 18,721	$ 18,721	$ -	
536	Energy - All kWh	kWh	232,020	7,663,639	7,895,659	$0.01439	$0.01591	$0.01315	$0.01732	$ 125,278	$ 135,816	$ 10,537	
537	Penalty kWh	kWh				$0.06736	$0.04602	$0.07432	$0.07601	$ (4)		$ 4	
538	Base Revenue									$ 164,901	$ 185,739	$ 20,838	
539													
540	**14.07 Fixed Time of Service Rider - CT Metering (Rates 302, 885)**												
541	Customer Charge	Bills			519	$6.70	$6.70	$10.00	$10.00	$ 3,477	$ 5,190	$ 1,713	
542	Facilities Charge	Bills			519	$38.00	$38.00	$38.00	$38.00	$ 19,722	$ 19,722	$ -	
543	Energy - All kWh	kWh	159,031	5,579,743	5,738,774	$0.01439	$0.01591	$0.01315	$0.01732	$ 91,070	$ 98,755	$ 7,684	
544	Penalty kWh	kWh				$0.06736	$0.04602	$0.07432	$0.07601	$ (2)		$ 2	
545	Base Revenue									$ 114,268	$ 123,667	$ 9,399	
546													
547	**14.07 Fixed Time of Service Rider Primary CT Metering (Rates 303, 886)**												
548	Customer Charge	Bills			-	$6.70	$6.70	$10.00	$10.00				
549	Facilities Charge	Bills			-	$18.00	$18.00	$18.00	$18.00				
550	Energy - All kWh	kWh			-	$0.01133	$0.01585	$0.01309	$0.01726				
551	Penalty kWh	kWh			-	$0.06736	$0.04602	$0.07132	$0.07601				
552													
553	**Adjustments for Riders Included in Base Rates**												
554	Renewable Resource Recovery Rider with CWIP Adjustment									$ 17,479	$ (19,558)	$ (37,037)	
555	Transmission Cost Recovery Rider with CWIP Adjustment									$ 12,142	$ -	$ (12,142)	
556	Advanced Meter & Distribution Technology Rider with CWIP adjustment									$ 22,418	$ 18,728	$ (3,690)	
557	Generation Cost Recovery Rider									$ 8,803	$ -	$ (8,803)	
558	Energy Adjustment Rider									$ 373,888	$ 412,667	$ 38,779	
559										$ 10,249	$ 10,620	$ 371	
560	**Total Adjustments:**									$ 444,979	$ 422,458	$ (22,521)	
561													
562													
563	**Total Base Revenue for the COSS Class:**									$ 279,169	$ 309,406	$ 30,237	10.83%
564	**Total Adjustments for the COSS Class:**									$ 444,979	$ 422,458	$ (22,521)	-5.06%
565	**Total for the COSS Class:**									$ 724,148	$ 731,864	$ 7,715	1.07%
566													
567													
568													
569	**Total Base Revenue:**									$ 114,030,810	$ 159,556,559	$ 45,525,749	39.92%
570	**Total Adjustments:**									$ 92,511,010	$ 69,447,741	$ (23,063,269)	-24.93%
571	**TOTAL:**									$ 206,091,796	$ 228,554,279	$ 22,462,483	10.90%
572													

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumers
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: August 12, 2024
Responding Witness: David G. Prazak, Manager, Pricing & Rate Design - (218) 739-8595

Data Request:
Please provide the duo decile chart (Figure 7 in David Prazak's direct testimony) by voltage. Please provide the same information using the revised revenue requirements in supplemental testimony. Please provide in excel spreadsheet format with formulae intact.

Attachments: 4
Attachment 1 to DR ND-MLEC-305
Attachment 2 to DR ND-MLEC-305
Attachment 3 to DR ND-MLEC-305_PUBLIC
Attachment 4 to DR ND-MLEC-305_PUBLIC

Response:

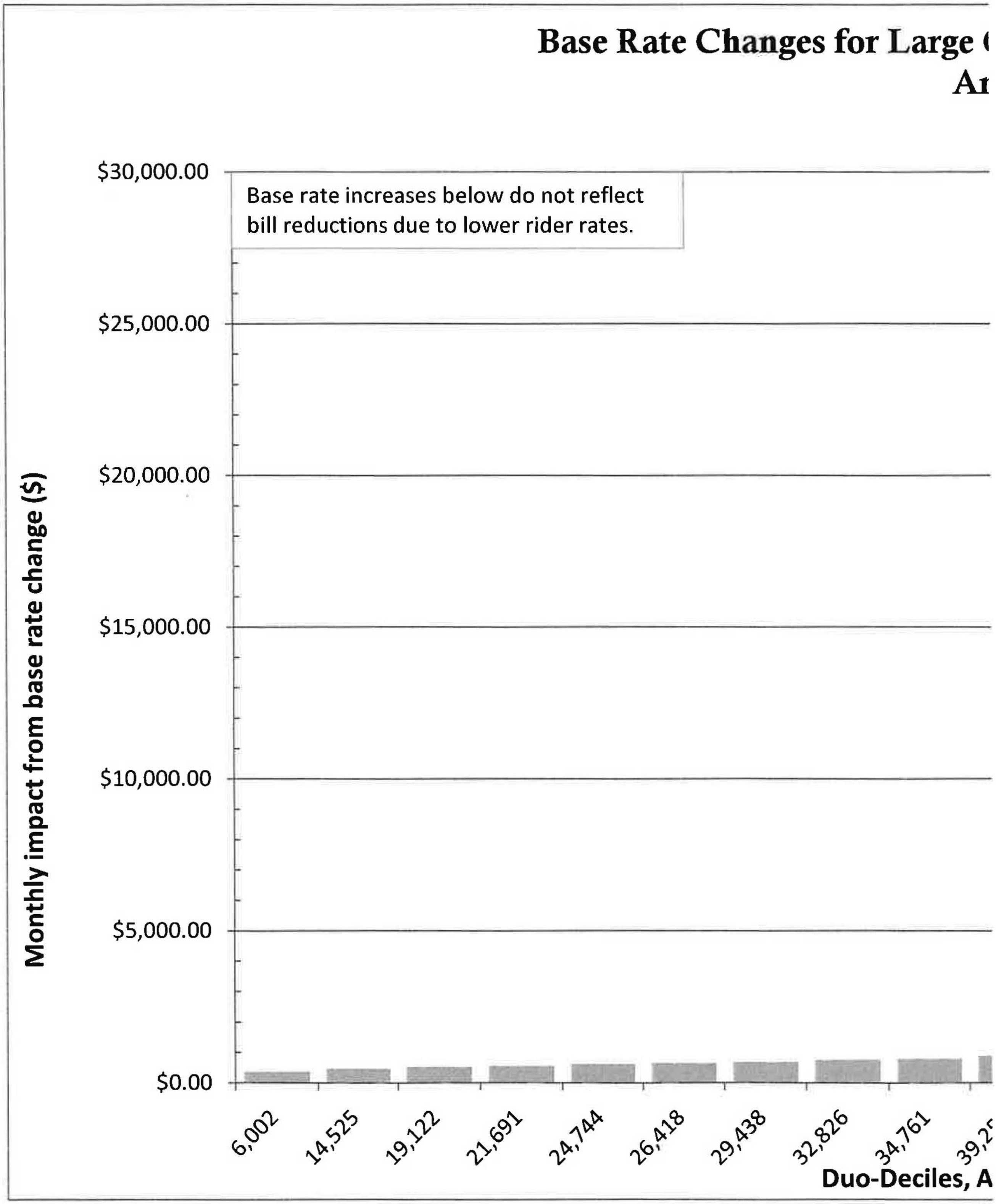
Attachments 3 and 4 to DR ND-MLEC-305 contains trade secret, proprietary, commercial, or financial information, as defined in N.D.C.C. §§ 44-04-18.4 and 47-25.1-01(4) and subject to restrictions against disclosure and unauthorized use under North Dakota law and the Order on Protection of Information dated January 18, 2024. Specifically, Attachments 3 and 4 to DR ND-MLEC-305 contains customer-specific energy usage information, which is of a privileged nature and has not been previously publicly disclosed. This information also has independent economic value to the customers themselves, who derive value from OTP's efforts to maintain its confidentiality.

Please see Attachments 1-4 to DR ND-MLEC-305 for duo decile charts by voltage in Excel spreadsheet format with formulae intact. Attachment 1 to DR ND-MLEC 305 reflects large general service secondary customers from OTP's Direct Testimony. Attachment 2 to DR ND-MLEC 305 reflects large general service secondary customers from OTP's Supplemental Testimony. Attachment 3 to DR ND-MLEC 305 reflects large general service primary customers from OTP's Direct Testimony. Attachment 4 to DR ND-MLEC 305 reflects large general service primary customers from OTP's Supplemental Testimony.

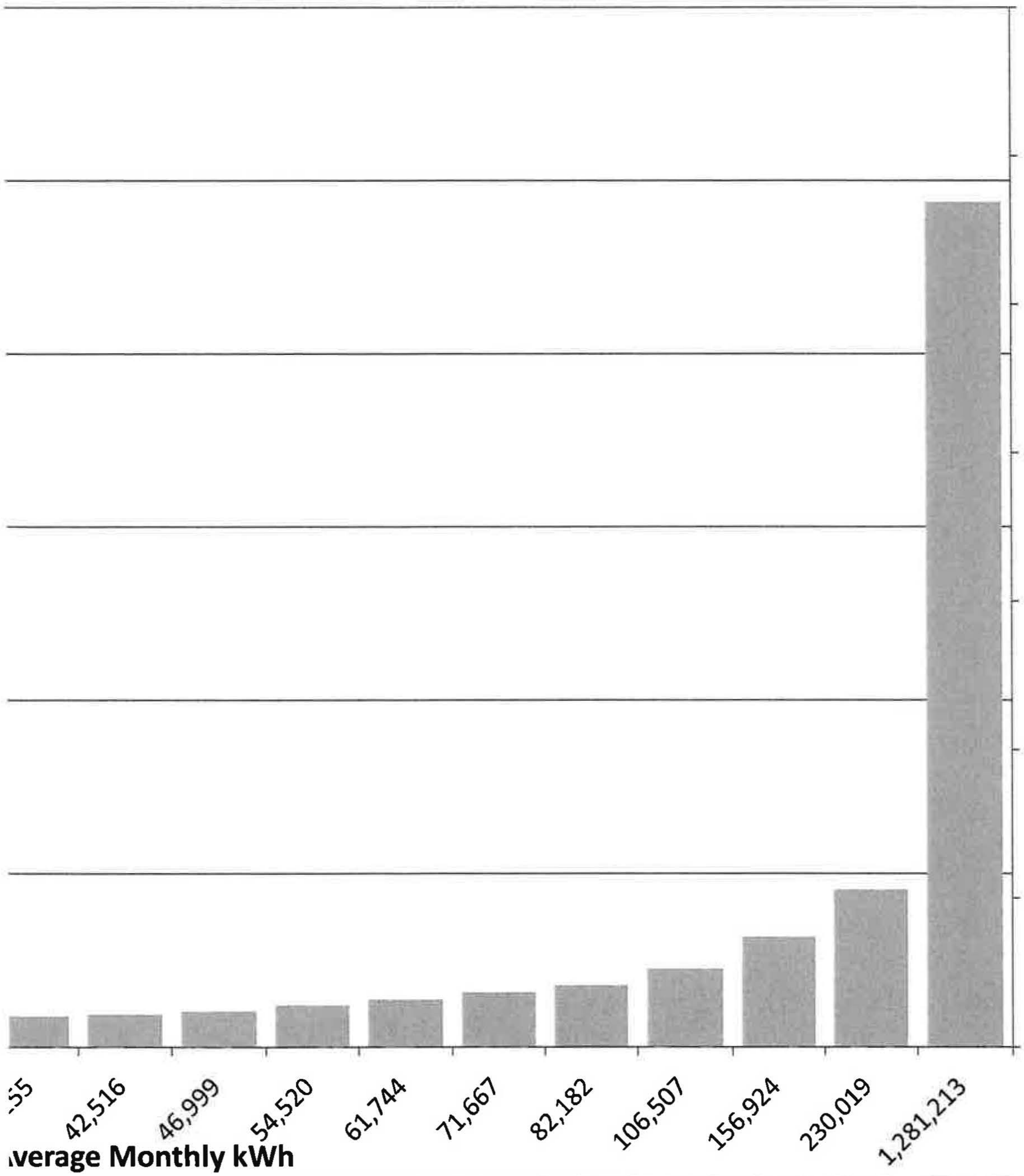
Base Rate Changes for Large General Service Secondary 10.04
Annual

(linked to Chart Title)

Horizontal Axis & Label	Vertical Axis & Label_1		Vertical Axis & Label_2
Duo-Deciles, Average Monthly kWh	**Monthly impact from base rate change ($)**	**T**	**Percent Total Bill Change**
6,002	$362.45		27%
14,525	$458.19		33%
19,122	$528.14		35%
21,691	$553.25		35%
24,744	$610.10		37%
26,418	$644.97		38%
29,438	$683.38		38%
32,826	$747.04		38%
34,761	$786.37		39%
39,255	$886.96		40%
42,516	$943.88		40%
46,999	$1,030.89		41%
54,520	$1,206.67		42%
61,744	$1,371.21		41%
71,667	$1,582.17		42%
82,182	$1,783.00		43%
106,507	$2,258.10		43%
156,924	$3,169.61		44%
230,019	$4,537.91		44%
1,281,213	$24,388.37		47%


Base Rate Changes for Large (
A
Base rate increases below do not reflect bill reductions due to lower rider rates.
Monthly impact from base rate change ($)
$30,000.00
$25,000.00
$20,000.00
$15,000.00
$10,000.00
$5,000.00
$0.00
6,002
14,525
19,122
21,691
24,744
26,418
29,438
32,826
34,761
Duo-Deciles, A

General Service Secondary 10.04
ınual

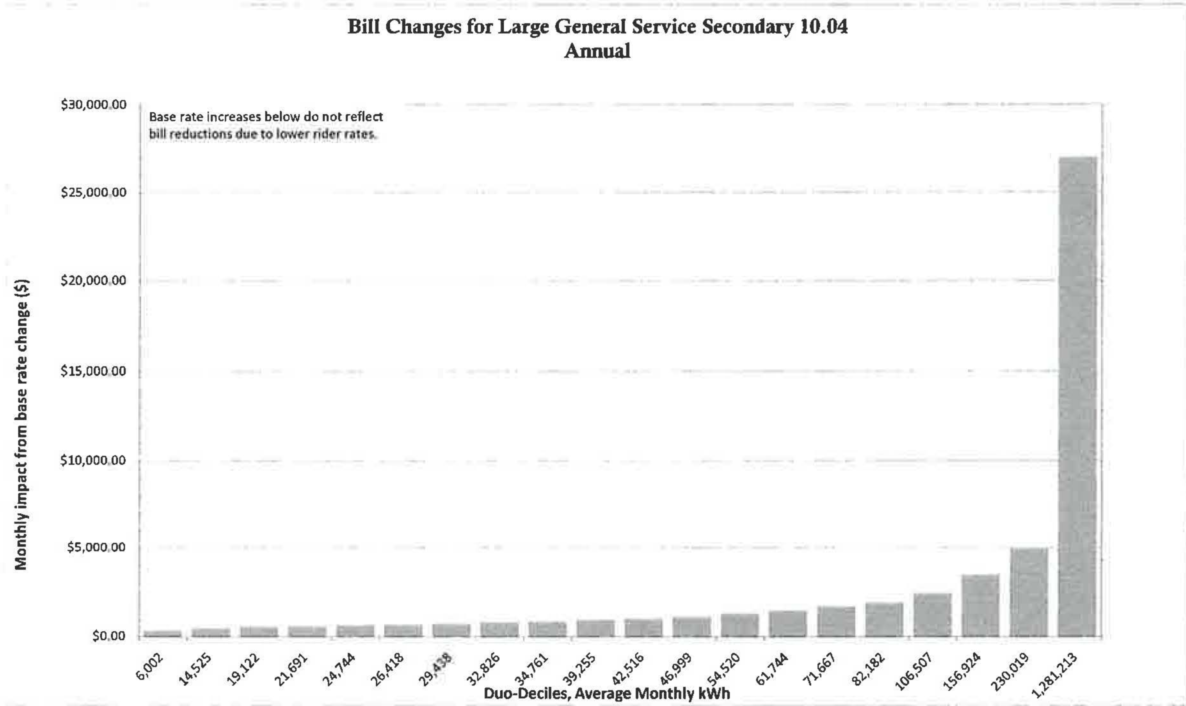


	Annual		
decile	Average kWh	Average Revenue Impact	Percent Impact
1	6002.3917	362.45267	0.2727201
2	14525.115	458.18726	0.3267672
3	19122.407	528.13865	0.3490424
4	21690.803	553.24697	0.345631
5	24744.422	610.10013	0.368601
6	26418.345	644.97195	0.3805246
7	29437.661	683.37812	0.3794442
8	32825.984	747.04376	0.3847393
9	34760.689	786.373	0.3911467
10	39254.609	886.95648	0.4015804
11	42516.072	943.87901	0.4029017
12	46999.373	1030.8936	0.4054717
13	54519.526	1206.6714	0.4155113
14	61744.134	1371.2149	0.4144385
15	71666.748	1582.1665	0.4245016
16	82182.49	1782.9953	0.4301881
17	106506.87	2258.1044	0.4270006
18	156923.92	3169.6063	0.436021
19	230018.91	4537.9125	0.4371672
20	1281213	24388.368	0.4651094

Bill Changes for Large General Service Secondary 10.04
Annual

(linked to Chart Title)

Horizontal Axis & Label	Vertical Axis & Label_1	Vertical Axis & Label_2
Duo-Deciles, Average Monthly kWh	**Monthly impact from base rate change ($)**	**Percent Total Bill Change**
6,002	$348.45	26%
14,525	$469.49	33%
19,122	$549.46	36%
21,691	$587.23	37%
24,744	$644.62	39%
26,418	$679.46	40%
29,438	$729.40	40%
32,826	$800.34	41%
34,761	$841.92	42%
39,255	$946.72	43%
42,516	$1,011.92	43%
46,999	$1,108.35	44%
54,520	$1,291.42	44%
61,744	$1,469.36	44%
71,667	$1,693.98	45%
82,182	$1,914.59	46%
106,507	$2,446.16	46%
156,924	$3,470.41	48%
230,019	$5,005.88	48%
1,281,213	$27,046.08	52%



	Annual		
decile	Average kWh	Average Revenue Impact	Percent Impact
1	6002.3917	348.45259	0.2621861
2	14525.115	469.49062	0.3348285
3	19122.407	549.46417	0.3631363
4	21690.803	587.22696	0.3668594
5	24744.422	644.62007	0.3894567
6	26418.345	679.45529	0.4008692
7	29437.661	729.39571	0.4049953
8	32825.984	800.34183	0.4121886
9	34760.689	841.92096	0.4187765
10	39254.609	946.72194	0.42864
11	42516.072	1011.9208	0.4319458
12	46999.373	1108.35	0.4359369
13	54519.526	1291.4216	0.4446946
14	61744.134	1469.3644	0.4441034
15	71666.748	1693.9763	0.4545006
16	82182.49	1914.592	0.4619388
17	106506.87	2446.1595	0.4625612
18	156923.92	3470.4058	0.4773999
19	230018.91	5005.8783	0.4822494
20	1281213	27046.076	0.5157944

[PROTECTED DATA BEGINS…

Case No. PU-23-342
Attachment 3 to DR ND-MLEC-305
is CONFIDENTIAL in its Entirety

…PROTECTED DATA ENDS]

[PROTECTED DATA BEGINS…

Case No. PU-23-342
Attachment 4 to DR ND-MLEC-305
is CONFIDENTIAL in its Entirety

…PROTECTED DATA ENDS]

OTTER TAIL POWER COMPANY
Case No: PU-23-342

Response to: Midwest Large Energy Consumers
Analyst: Richard Savelkoul
Date Received: July 29, 2024
Date Due: August 12, 2024
Date of Response: August 12, 2024
Responding Witness: Christopher Byrnes Supervisor Regulatory Analysis, 218-739-8282

Data Request:
Please provide the average annual cost of energy for each of the years since 2020.

Attachments: 0

Response:

Refer to Table 1 below for the average annual historic and forecast EAR rates.

Table 1: Historic and Forecast EAR Annual Rates

	2020	2021	2022	2023	2024 (1)
ND EAR	0.01588	0.02535	0.03098	0.31087	0.02979

(1) Calculated from EAR Data Used to Develop 2024 Test Year