MLEC

ENERGY ANALYSIS, REPORTING AND ADVOCACY

Direct Testimony of
Kavita Maini

Before the
North Dakota Public Service Commission

In the Matter of Otter Tail Power Company 2017
Electric Rate Increase Application

CASE NO.: PU-17-398

Exhibit __

May 18, 2018

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Prefiled Direct Testimony of Kavita Maini with attachments
Midwest Large Energy Consumers - Intervenors
Richard Savelkoul, Martin Squires, P.A.

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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. 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 taking service from Otter Tail Power Company ("OTP" or "Company") on its Large General Service rate schedules.

Q. PLEASE STATE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I am an economist with more than 26 years of experience in the energy industry. I graduated from Marquette University, Milwaukee, Wisconsin with Master's Degrees in Business (1986) and in Applied Economics (1991). From 1991 to 1997, I worked for Wisconsin Power & Light as a Market Research Analyst and Senior Market Research Analyst. 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. Since 2002, I have been an independent consultant. I represent the Midwest Industrial Customers (MIC) at MISO. The MIC is a coalition of four end user associations including the Wisconsin Manufacturers and Commerce, American Forestry & Paper Association, Wisconsin Paper Council and Wisconsin Industrial Energy Group.

Q. HAVE YOU EVER PARTICIPATED IN OTHER UTILITY PROCEEDINGS?

A. Yes, I have testified before a number of state regulatory commissions, including Wisconsin, Minnesota, Missouri, Iowa, North Dakota and South Dakota. I have submitted technical comments on a variety of issues related to energy policy, cost

recovery, revenue allocations and rate design in transmission and renewable rider proceedings. I have also provided technical comments in Federal Energy Regulatory Commission ("FERC") proceedings, several of which have involved MISO-related activities. Ex. __(KM-1), Attachment 1 , is a summary of my experience testifying and providing comments related to a variety of energy-related matters in various jurisdictions.

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my direct testimony is to address and recommend issues related to revenue requirement, class cost of service, revenue apportionment to customer classes, revenue apportionment and rate design related issues within the Large General Service class and the proposed Super Large General Service rate.

II. REVENUE REQUIREMENT ISSUES

A. Tax Cuts And Jobs Act ("TCJA")

Q. DID THE TCJA HAVE AN IMPACT ON OTP'S REVENUE REQUIREMENTS?

A. Yes. As noted in OTP witness Tyler Akerman's supplemental testimony, the TCJA has four primary impacts on the utility's cost of service:

- The income tax expense will be reduced as a result of the reduction in federal income tax rate from 35% to 21%;
- Bonus depreciation is eliminated, which increase rate base and increases revenue requirement;
- An excess deferred income tax balance which reduces revenue requirements; and
- The tax gross up factor will be reduced from a gross-up factor of 1.607756 to 1.322837, which reduces the revenue requirement.

MLEC members appreciate OTP's proactive approach to voluntarily requesting the Commission's approval to reduce the interim rate from 10.64% to 6.79% as of March 1, 2018 as a result of the TCJA impacts. The Commission granted this request.

Q. WHAT ISSUE REGARDING THE TCJA IMPACTS DO YOU WISH TO DISCUSS?

A. I discuss the TCJA impacts that result in the creation of excess deferred income taxes.

Q. PLEASE EXPLAIN HOW THE EXCESS DEFERRED INCOME TAX BALANCE IS CREATED.

A. As a result of differences between tax laws and accounting methods, a utility's accumulated deferred income tax (ADIT) balance generally represents taxes to be paid by a utility in a future year. The ADIT balances are created because there are timing differences between when revenues and expenses are recognized for tax purposes compared to when they are recognized by Generally Accepted Accounting Principles (GAAP). The reduction of the federal tax rate from 35% to 21% has resulted in an excess deferred income taxes (EDIT) balance, which will no longer need to be paid in a future year. I note that the ADIT and EDIT balances are a reduction to rate base, which therefore, reduces revenue requirements.

Q. CAN THE EDIT BALANCE BE RETURNED TO CUSTOMERS IN A SINGLE YEAR?

A. Not the entire amount. This is because the EDIT balance consists of protected and unprotected balances. The protected portion of the EDIT is related to accelerated depreciation and according to Internal Revenue Service rules, is required to be amortized no faster than the life of the underlying assets. The remaining portion of the EDIT is unprotected and maybe amortized over a shorter period or recognized immediately.

Q. WHAT IS OTP'S UNPROTECTED EDIT BALANCE?

A. Based on the Company's response to ND-MLEC-141 (Exhibit ___ (KM-1), Attachment 2), the unprotected grossed up balance is ($1,230,510) on a total Company basis or ($444.063) on a North Dakota Jurisdictional basis.

Q. WHAT IS OTP'S PROPOSAL TO DEAL WITH THE UNPROTECTED GROSSED UP BALANCE?

A. In response to ND-MLEC-141, OTP proposes to amortize this amount in the same manner as the protected EDIT balance, over a period of 25 years.

Q. WHAT IS YOUR RECOMMENDATION?

A. My recommendation is that the ($444,063) EDIT unprotected amount applicable to the North Dakota jurisdiction be recognized in the rate case to offset the 2018 test year revenue requirements.

B. Customer Information System (CISone)

Q. PLEASE DESCRIBE THE CISONE PROJECT.

A. OTP witness Stuart Tommerdahl indicates that the CISone project is a new customer information system being implemented to replace an existing legacy system that the Company built internally and has been using for almost 30 years.

Q. WHAT IS THE ANTICIPATED IN-SERVICE DATE?

A. In supplemental testimony, Mr. Tommerdahl indicates that the current estimated "go-live" date for CISone is by the end of 2018. Mr. Tommerdahl also indicated that the Company will continue to provide updates regarding the in-service date through the proceeding.

Q. WHAT ARE THE REVENUE REQUIREMENTS ASSOCIATED WITH THE PROJECT?

A. In response to ND-MLEC-138 (Exhibit ___ (KM-1), Attachment 3), the Company indicates that the revenue requirement for the North Dakota jurisdiction is $1.22 million. This revenue requirement incorporates the lower gross up rate associated with the TCJA and is based on an amortization period of 5 years. In supplemental testimony, the Company increased the amortization period to 10 years.

Q. WHAT IS YOUR CONCERN ABOUT THE REVENUE REQUIREMENTS?

A. I am concerned that for purposes of calculating the revenue requirements for CISone, the Company appears to assume that this information system is operational throughout the test year. As noted in Mr. Akerman's direct testimony, the plant in-service is annualized and other normalization adjustments are included. I believe that it would be more appropriate to incorporate the related adjustments (i.e., classify to plant in service,

accumulated depreciation, depreciation expense, etc.) once the project is in-service and used and useful instead of the Company's annualization approach.

Q. HOW CAN THIS ISSUE BE ADDRESSED?

A. To the extent the CISone is not operational in 2018, the project should be reclassified as Construction Work in Progress (CWIP). If the CISone project is operational in 2018, the revenue requirements should be prorated depending on the in-service date. For example, if the project goes "live" on October 1, 2018, the company should include revenue requirements associated with only the last quarter of 2018. The Company should provide the confirmed in-service date of the project in rebuttal testimony and the adjusted revenue requirement after appropriately reversing the annualization for this project. Further, the Company should also confirm in rebuttal testimony that to the extent there are any cost savings associated with eliminating the old system (such as staff, overhead, consulting etc.), such savings have been incorporated and any duplication of costs between the old and new system has been eliminated.

C. Generation Cost Recovery (GCR) Rider

Q. PLEASE BRIEFLY DESCRIBE THE ASTORIA PROJECT.

A. The Astoria project is a 250 MW natural gas fired, simple cycle combustion turbine to be located in Astoria, South Dakota. OTP expert witness Mr. Stuart Tommerdahl indicates that this project, along with the Merricourt Wind project, were selected to meet customer needs in a least cost manner. The Astoria project is being constructed in large part, to replace the Hoot Lake plant which is expected to retire in 2021, the same year the Astoria project is expected to be placed in service.

The North Dakota Public Service Commission approved the advanced determination of prudence for this project in docket PU-17-140 on November 3, 2017. The Commission approved a Settlement between North Dakota Public Service Commission Advocacy Staff and the Company (the "Settlement"). According to the Settlement, the Company

may request cost recovery through applicable riders, a general rate case or any other authorized mechanisms.

Q. WHAT IS OTP'S PROPOSED COST RECOVERY MECHANISM FOR THIS PROJECT?

A. OTP is requesting the Commission's approval of a GCR Rider to recover costs associated with the Astoria project. Similar to other rider recovery mechanisms, OTP proposes that the GCR Rider would include a tracker to capture and track costs associated with the Astoria project. The Company would submit annual filings and reset the GCR Rider rate each year depending on the amount of actual recovery and future costs to be incurred. OTP is not proposing a rate to be charged to customers in this filing. Rather, the request is only for the establishment of the GCR Rider.

Q. WHAT ARE YOUR RECOMMENDATIONS REGARDING THE ESTABLISHMENT OF THE GCR RIDER FOR COST RECOVERY ASSOCIATED WITH THE ASTORIA PROJECT?

A. In addition to adhering to the terms of the Settlement (which included provisions for actual costs being over or under the authorized amount of $181.5 million), I recommend the following:

- First, the Astoria project costs should be recovered through the Rider for a minimum of 3 years after this project is placed in service. Such an approach will assist in incorporating the impacts of depreciation and lowering the revenue requirement in a more timely fashion as opposed to folding these costs in base rates soon after the project is placed in service.
- Second, the savings associated with the retirement of Hoot Lake should be incorporated in the GCR Rider. Since the Astoria project is being constructed, in large part, to replace the Hoot Lake capacity, it is reasonable and fair to include the savings associated with retiring the Hoot Lake plant at the same time when the Astoria project is placed in service.

Q. DID OTP PROVIDE THE REVENUE REQUIREMENT ASSOCIATED WITH HOOT LAKE IN THE TEST YEAR 2018?

A. Yes. In response to ND-MLEC-134, (Exhibit ___ (KM-1), Attachment 4), the Company indicated that $4,625,806 are included in the test year for the Hoot Lake plant (North Dakota Jurisdiction). This includes return on and of investment, as well as costs to operate the plant excluding fuel-related costs. Once the plant retires in 2021, these costs will no longer be incurred, thereby resulting in savings. Thus, these savings should offset the revenue requirement increases associated with the Astoria project in the GCR Rider.

Q. WHAT IS THE PROPOSED COST RECOVERY APPROACH ASSOCIATED WITH THE GCR RIDER?

A. OTP witness Mr. David Prazak explains that the proposed cost recovery approach is the same as its current Environmental Cost Recovery Rider (ECRR). Like the ECRR, the proposed GCR Rider utilizes a cost recovery factor which will apply to customers' bills on a percent of base rates basis. The rate will initially be set at 0%. The Company will make a separate filing to request approval of cost recovery sometime in late 2018, or early 2019.

Q. DO YOU SUPPORT THIS COST RECOVERY APPROACH?

A. Yes, I do. The percent of base rate approach does not alter the rate design that would be finalized in this case and inherently represents energy and demand related costs.

D. Impact of the TCJA on the Production Tax Credits (PTC)

Q. WHAT IS THE IMPACT OF THE TCJA ON THE PTCS IN THE RENEWABLE RESOURCE ADJUSTMENT RIDER (RRAR)?

A. As indicated by Mr. Bryce Haugen, the Company earns PTCs for certain of its wind facilities. The PTCs are credits against taxable income and are utilized against the Company's tax expense in the year that they are generated. The unused PTCs are carried forward as a deferred tax asset that increases rate base. Since the income tax obligation is reduced due to the TCJA, it will result in delaying when OTP can utilize the PTCs on future tax returns. Under OTP's proposal, the deferred tax asset will be rolled into base rates at the conclusion of this case. The deferred tax asset amount will be larger

compared to the Company's initial proposal due to the TCJA impact of reducing the tax obligation compared to the original proposal.

Q. WHAT DID OTP ESTIMATE AS THE REVENUE REQUIREMENT IMPACT OF THE LARGER DEFERRED TAX ASSET?

A. OTP estimated a revenue requirement increase of $250,000 to $500,000 on a North Dakota jurisdictional basis. Mr. Haugen's supplemental testimony indicates that the actual amount depends upon the actual PTCs generated at the time final rates go into effect. Mr. Haugen also indicates that the Company will provide an updated RRAR schedule as part of the final rider roll-in that will include the most updated amounts.

Q. WHAT IS THE PROJECTED AMOUNT OF UNUSED PTC BALANCE?

A. In response to ND-MLEC-150 (Exhibit ___ (KM-1), Attachment 5), the Company indicates that the projected unused PTC balance for the North Dakota jurisdiction for the month ending September 2018 is $1,955,132 for Langdon and $11,786,401 for Ashtabula respectively. If the Company's proposal is accepted, these amounts will be folded into base rates at the conclusion of the current case.

Q. HOW WOULD THE REVENUE REQUIREMENT BE IMPACTED IF THE COMPANY WERE TO UTILIZE THE UNUSED PTC BALANCES FOR LANGDON AND ASHTABULA BETWEEN RATE CASES?

A. The revenue requirement would be reduced. For example, if the Company utilized all of the unused PTC balance between rate cases, the revenue requirement decrease associated with Langdon and Ashtabula would be $189,861 and $1,139,745 on a North Dakota jurisdictional basis. These amounts were calculated by multiplying the unused PTC balances for each of the wind plants by the revenue requirement factor of 9.67%. The revenue requirement factor calculation is provided in response to ND-MLEC-134.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE UNUSED PTC BALANCE?

A. I recommend that the Company track the utilization of the unused PTC balance and provide the offsetting reduction to the revenue requirements through the RRAR on an annual basis. The Company should make an annual filing documenting the amounts and seek Commission approval.

III. NON REVENUE REQUIREMENT ISSUES

A. Importance of Competitive Industrial Rates

Q. HOW ARE MLEC MEMBERS IMPACTED BY THIS PROCEEDING?

A. Many of MLEC member companies operate energy intensive facilities and are therefore sensitive to energy cost increases, which affect their overall cost of doing business. Thus, energy affordability affects the competitiveness, output and potential employment levels for these companies. High energy costs directly impact the bottom line of industrial customers because in many cases, these costs cannot be passed to downstream customers or markets due to highly competitive business conditions. In cases where companies have multiple facilities, the competition is also amongst sister companies or locations with respect to attracting capital investment dollars.

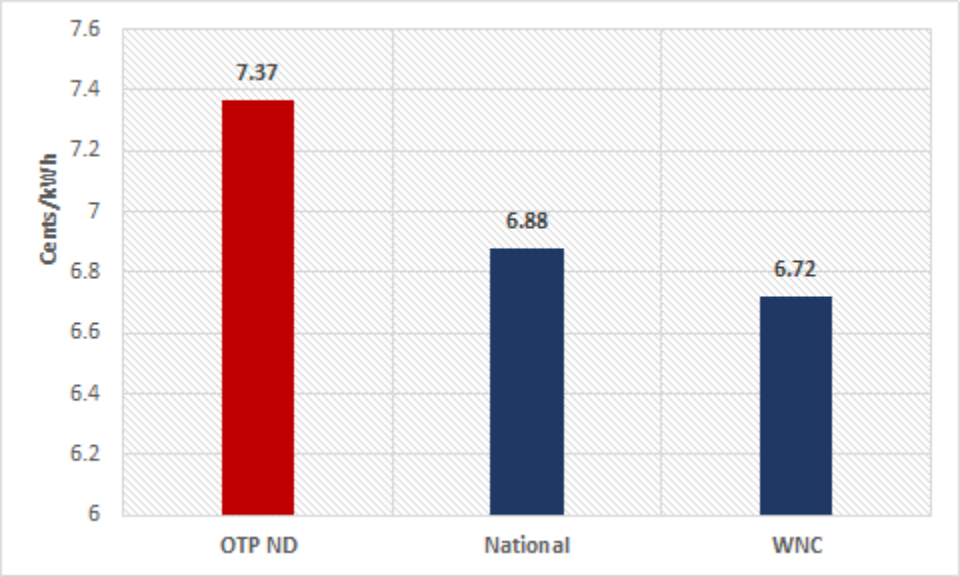
OTP's average industrial rate is not competitive compared to regional and national averages. The current proposed increases to the LGS class will further exacerbate this situation.

Q. WHAT IS YOUR BASIS FOR STATING THAT OTP'S NORTH DAKOTA INDUSTRIAL RATES ARE NOT COMPETITIVE?

A. I compared OTP's North Dakota average industrial rate with the average industrial regional and national average industrial rates respectively. **Figure 1** shows the comparison for bills effective July 1, 2017. The data for the charts was provided by OTP in response to ND-MLEC-116 (Exhibit ___ (KM-1_, Attachment 6). As can be observed from this chart, OTP's North Dakota average industrial rate is the highest when compared to the regional and national averages respectively – 9.7% above the regional average and 7.1% above the national average.

Figure 1: Average Industrial Rate Comparisons

Comparisons for Bills Effective July 1, 2017



Furthermore, according to data provided in ND-MLEC-116, the industrial rate competitiveness has declined further when compared to the national average in the last three years -- in 2015, OTP's average industrial rate in North Dakota was 2.7% above the national average and in 2017, it was 7.1% above the national average.

Q. WHY ARE COMPETITIVE INDUSTRIAL RATES IMPORTANT?

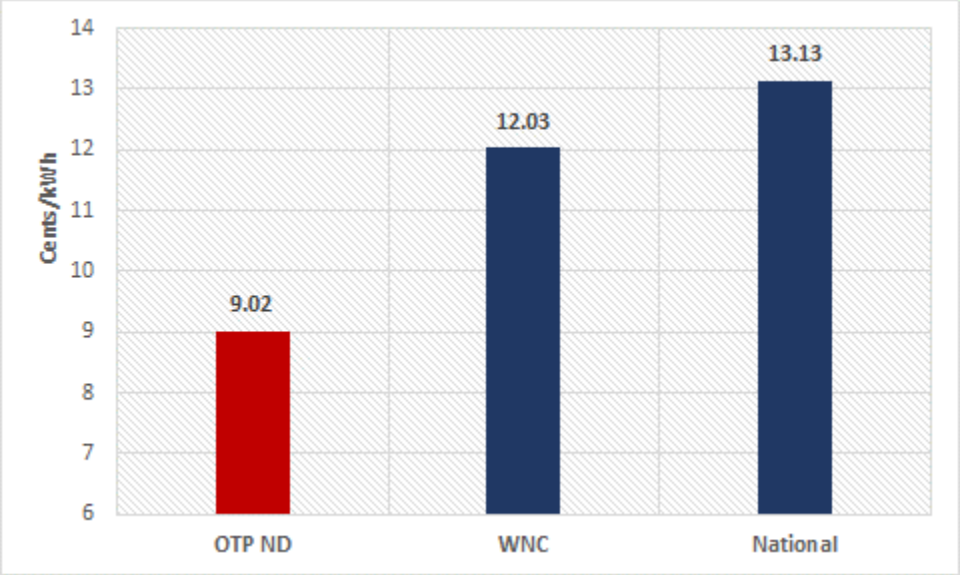
A. Competitive industrial rates are an important factor in helping to retain and expand industry within the utility's service area. Business retention and expansion result in positive impacts on local economy and employment. Further, if businesses relocate or expand in OTP's service area, it has the potential of lowering costs for customers as the fixed costs are spread over larger amounts of billing determinants. The converse is also true – if businesses shift operations from OTP's area, the remaining customers bear the burden of the same fixed costs, but over a smaller amount of billing determinants, thereby increasing rates for all customers. Shifting production to other states also negatively impacts the local economy, employment and taxes. Thus, declining rate competitiveness adversely impacts not only the affected industrial plants, but has a snowball impact on the State's economy, employment and electricity rates.

Faced with large rate increases, industrial customers would also be more inclined to consider on-site generation options, particularly given competitive natural gas prices, which once again results in a similar effect as the utility losing load and remaining customers facing larger increases.

Q. HOW DO OTP'S NORTH DAKOTA RESIDENTIAL RATES COMPARE ON A REGIONAL AND NATIONAL LEVEL?

A. **Figure 2** shows the comparison. While OTP's industrial rates are 9.7% and 7.1% above the regional and national averages, the Company's North Dakota residential rates are 25% and 31% below the regional and national averages respectively.

Figure 2: Average Residential Rate Comparisons for Bills Effective July 1, 2017

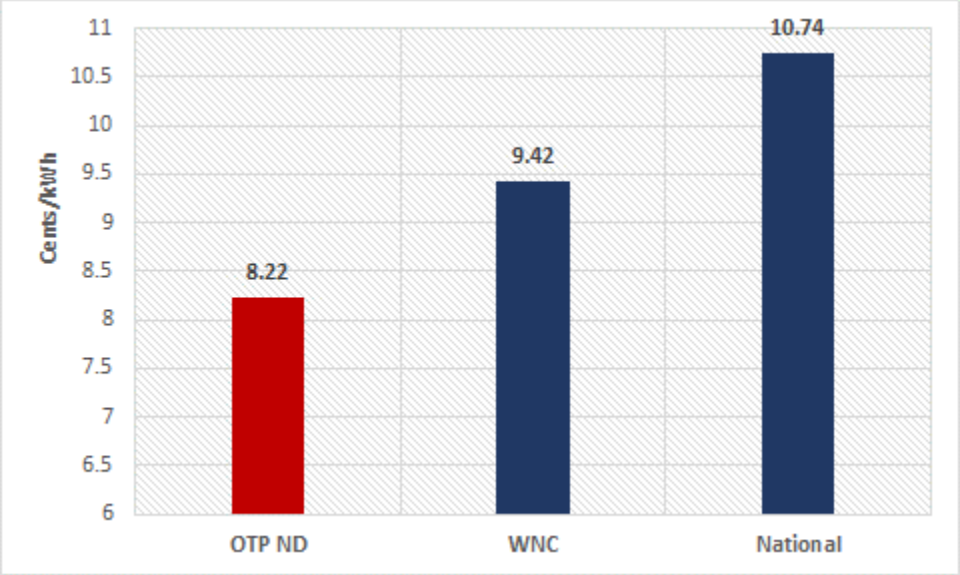


Q. HOW DO OTP'S NORTH DAKOTA OVERALL AVERAGE RATES COMPARE WITH THE NORTH DAKOTA AVERAGE ON A REGIONAL AND NATIONAL LEVEL?

A. **Figure 3** shows the total average rate comparison. On an overall average (average of all rate classes) rate basis, OTP's average rates are around 13% and 23% lower than the regional and national averages respectively. Similarly, the average commercial rate is 3.5% and 14.5% lower than the regional and national averages.

Thus, overall, the Company's North Dakota higher average industrial rate is the only one rate that is not competitive when compared to regional and national averages.

Figure 3: Average Rate Comparisons for Bills Effective July 1, 2017



Q. WHAT COULD BE CAUSING THE INDUSTRIAL RATES TO BE RELATIVELY LESS COMPETITIVE THAN THE RESIDENTIAL RATES AND OVERALL AVERAGE RATE RESPECTIVELY?

A. A critical factor could be not assigning costs to those that cause them resulting in subsidization by the industrial class. If a Class Cost of Service Study (CCOSS) approach does not reflect cost causation, costs are not allocated to those that cause them resulting in inequity amongst classes and unreasonable rates for classes that are paying more than it costs to serve them. Further, if revenue apportionment to each class is not aligned with the CCOSS or closer to CCOSS results, this once again results in inequity amongst classes as some classes share a disproportionate cost of service burden than appropriate. Indeed, as noted later in my testimony, the revenue responsibility for some classes is significantly below cost while other classes, such as the LGS class, the revenue responsibility is significantly above cost – these results are based on the Company's CCOSS, which as noted below is already punitive to high load factor classes such as the LGS class.

B. Class Cost of Service Study (CCOSS) Issues

1. Importance of A Utility's Cost of Service

Q WHAT IS THE IMPORTANCE OF A UTILITY'S COST OF SERVICE?

A. A utility's cost of service is the fundamental basis for establishing just and reasonable rates in the ratemaking process. The cost of service 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 the rate revenues to equal the utility's cost of service.

Revenue allocation to classes: Given a certain revenue requirement, a utility's cost of service guides the manner in which a given revenue requirement should be allocated to classes. The level of the revenue requirement for each class is based on each class 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 rate design in that it helps set the rates with the goal of providing pricing signals to customers and recovering the costs to serve the customers in a particular tariff.

Q. FOR A GIVEN REVENUE REQUIREMENT, WHAT IS THE IMPACT OF CLOSELY ALIGNING REVENUE ALLOCATION TO CLASSES AND RATES WITH COSTS TO SERVE?

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

Q. PLEASE EXPLAIN HOW EQUITY IS PROMOTED AMONG CLASSES.

A. If revenues are allocated to classes and align with the class cost responsibility resulting from a properly developed cost of service study, equity is maintained because each class pays its fair share of costs. To maintain the equity principle, a class not paying its fair share should receive an above system average increase while a class more than its fair

share should receive a below average increase. In cases where the class revenues are significantly misaligned with cost responsibility, larger corrections or adjustments maybe warranted in order to restore equity amongst classes. As discussed later in my testimony, such is the case with OTP's current situation where class revenues have significantly deviated from class cost responsibility.

Q. HOW IS ECONOMIC EFFICIENCY ACHIEVED?

A. If retail rates align with costs to serve, they reflect accurate pricing signals that drive consumer behavior, which in turn results in more efficient use of the system and minimizes system costs. If rates reflect costs to serve, there is equitable recovery of costs from classes and customers have the proper pricing signals and incentive to respond to. Failure to do so ultimately results in adverse consequences and higher costs for all customers.

In instances where the class revenue responsibility is set above cost, say for the industrial class, the resulting rates will be set at artificially high levels to meet the above cost revenue responsibility. Such rates would incent customers in this class to reduce production or shift production elsewhere. Such a consequence results in higher costs for all customers since the utility's fixed costs would need to be recovered from lesser billing determinants.

2. OTP CCOSS – Classification of Fixed Production Plant

Q. WHAT IS OTP'S CCOSS APPROACH FOR CLASSIFYING AND ALLOCATING FIXED PRODUCTION PLANT COSTS?

A. OTP uses the Equivalent Peaker (EP) method that consists of classifying significant amounts of fixed production plant related costs as energy related. Fixed production plants for baseload plants are classified as demand related up to the cost of a peaking unit. Costs in excess of the cost of a combustion turbine are classified as energy related. Since OTP has a significant amount of base load power, it classifies approximately 82% of fixed production plant costs as energy related. (see response to ND-PSC-12.07, Exhibit ___ (KM-1), Attachment 7).

Q. DO YOU SUPPORT THE COMPANY'S EQUIVALENT PEAKER (EP) APPROACH FOR CLASSIFYING AND ALLOCATING FIXED PRODUCTION PLANT COSTS?

A. No; I believe that the EP approach disproportionately allocates fixed production plant related costs to high load factors customers and classes that utilize the system more efficiently. Customer classes are discouraged from improving load factors because each additional kWh of off-peak usage results in additional base load fixed costs (return, depreciation, fixed O&M expenses) being assigned to the rate class. Therefore, in my opinion, this approach does not provide a fair allocation of costs to high load factor classes such as the LGS class.

I would note however, that in spite of the drawbacks associated with this approach, the Company's CCOSS shows that the LGS class should get a 5.56% decrease compared to the updated system increase of 6.64% submitted in supplemental testimony. **Table 1_** shows the results. This information was obtained in response to ND-MLEC-132. I also note that the class revenue responsibility has deviated significantly from the cost responsibility -- percent rate changes range from a negative 5.56% for the LGS class to a positive 86% for the irrigation class.

Table 1: OTP CCOSS Results for an Increase of 6.64%

	OTP CCOSS Results				
Class	Present Revenues	Amount of Increase	Percent Increase	CCOSS Based Revenue Responsibility	CCOSS Revenue Responsibility Share
Residential	$47,632,359	$8,248,124	17.32%	$55,880,483	35.82%
Farms	$2,573,882	$655,027	25.45%	$3,228,908	2.07%
General Service	$38,487,308	-$1,008,991	-2.62%	$37,478,316	24.03%
Large General Service	$42,613,778	-$2,370,949	-5.56%	$40,242,829	25.80%
Irrigation	$58,520	$50,403	86.13%	$108,922	0.07%
Lighting	$2,841,429	$481,491	16.95%	$3,322,919	2.13%
OPA	$1,188,731	$260,449	21.91%	$1,449,181	0.93%
Controlled Service Water Heating	$1,074,543	$454,660	42.31%	$1,529,203	0.98%
Controlled Service Interruptible	$8,296,431	$2,853,854	34.40%	$11,150,285	7.15%
Controlled Service Deferred	$1,506,746	$86,050	5.71%	$1,592,796	1.02%
	$146,273,726	$9,710,117	6.64%	$155,983,843	

Q. WHAT IS YOUR PREFERRED APPROACH FOR CLASSIFYING AND ALLOCATING FIXED PRODUCTION PLANT RELATED COSTS?

A. My preferred approach consists of classifying all fixed production plant related costs as demand related and allocated to customer classes on the basis of OTP's D1 allocator.

The generation infrastructure costs such as return on investment, depreciation, and fixed operations and maintenance costs are fixed in nature and do not vary with energy usage. Consequently, such costs are appropriately classified as demand related and allocated on the basis of the D1 allocator. This approach is valid and recognized in the NARUC manual as the Peak Demand method.

Q. WHAT ARE THE CCOS RESULTS USING THIS APPROACH?

A. **Table 2** shows the results. I am issuing a discovery request so that the Company can verify the results I provide here.

Table 2: MLEC Preferred CCOSS Results for an Increase of 6.64%

	MLEC CCOSS Results				
Class	Present Revenues	Amount of Increase	Percent Increase	CCOSS Based Revenue Responsibility	CCOSS Revenue Responsibility Share
Residential	$47,632,359	$10,432,366	21.90%	$58,064,725	37.22%
Farms	$2,573,882	$739,096	28.72%	$3,312,977	2.12%
General Service	$38,487,308	-$48,926	-0.13%	$38,438,382	24.64%
Large General Service	$42,613,778	-$4,756,218	-11.16%	$37,857,560	24.27%
Irrigation	$58,520	$46,035	78.67%	$104,555	0.07%
Lighting	$2,841,429	$435,961	15.34%	$3,277,389	2.10%
OPA	$1,188,731	$228,895	19.26%	$1,417,626	0.91%
Controlled Service Water Heating	$1,074,543	$312,879	29.12%	$1,387,422	0.89%
Controlled Service Interruptible	$8,296,431	$2,456,420	29.61%	$10,752,851	6.89%
Controlled Service Deferred	$1,506,746	-$136,390	-9.05%	$1,370,355	0.88%
	$146,273,726	$9,710,117	6.64%	$155,983,843	

Q. IF THE COMMISSION DETERMINES THAT THE COMPANY'S EP APPROACH REMAINS THE APPROPRIATE METHOD, WHAT ARE YOUR RECOMMENDATIONS?

A. My preference is to classify fixed production plant related costs using the peak demand method and allocate on the basis of the Company's D1 allocator. However, should the Commission determine that the Company's EP method remains appropriate, it is important that the various costs be assigned and allocated using proper cost causative principles using this method. In this regard, the Company has made positive efforts by incorporating the use of the E8760 allocator, which should be adopted. I discuss this issue below. I also have a recommendation regarding allocation of distribution costs to be investigated for the Company's next rate case.

3. E-8760 Allocator for Fuel Costs in Base Rates and Energy Adjustment Rider

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO ALLOCATION OF FUEL COSTS IN BASE RATES AND THE ENERGY ADJUSTMENT RIDER?

A. In accordance with the Commission's order in the Company's last base rate case in docket PU-08-862, that Company proposes to (a) move all fuel costs out of base rates and recover those costs entirely through the Energy Adjustment Rider and (b) allocate fuel costs to each costs based on an E8760 allocator.[1] Table 2 of witness Gina Ice's testimony shows the comparison of the base fuel cost allocations using a flat energy sales allocator versus the E-8760 allocator. This table shows that the flat kWh sales allocator results in over allocating costs to the LGS, Farm, Irrigation, Lighting and Controlled Service Deferred classes respectively and under allocating base fuel costs to all other class. A flat kWh allocator ignores energy cost and load variations and therefore, is not the proper allocator to be used to allocate fuel costs.

Q. DO YOU SUPPORT THE COMPANY'S PROPOSAL TO ALLOCATE FUEL COSTS USING THE E-8760 ALLOCATOR APPROACH?

A. Yes, I do. The E8760 allocator captures variations in energy costs and load and the resulting cost allocation to classes is therefore, done fairly and on a cost causative basis. Further, as noted earlier, this approach was ordered by the Commission in the Company's last rate case. Thus, I recommend that the Commission approve the Company's proposal to use E8760 allocator approach to allocate fuel costs.

Q. DO YOU SUPPORT RECOVERY OF THE ENTIRE FUEL COSTS THROUGH THE ENERGY ADJUSTMENT RIDER?

A. I can support recovery of the entire fuel costs through the Energy Adjustment Rider provided that the Company utilizes the E8760 allocator to allocate the fuel costs to classes. OTP witness Mr. Stuart Tommerdahl notes in his testimony that the current CIS system is not able to facilitate a separate fuel clause rate for each class. He proposes that

[1] See OTP witness Stuart Tommerdahl Direct Testimony on page 24.

until the new CIS system (CISone) is placed in service, the Company would use the flat KWh allocator method to allocate **all** of the fuel costs through the Energy Adjustment Rider. I am concerned that using the flat kWh allocator approach on the entire fuel costs will result in disproportionately allocating such costs to the LGS and other classes.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the Company utilize the current approach of recovering only the variations to the base cost of fuel through Energy Adjustment Rider until the CISone system is fully operational. Once the CISone project is fully operational, all of the fuel costs can be transferred to the Energy Adjustment Rider. By taking this approach, the flat kWh allocator will only be utilized on the deviations to the base cost of fuel while the Company is using the current CIS system. Once the CISone system is in place, the E8760 allocator can be applied to all of the fuel costs. In other words, the transfer of entire fuel costs to the Energy Adjustment Rider should be contingent upon the in-service and fully operational timing of the CISone system.

4. Distribution Costs – Single Phase Versus Three Phase Configuration

Q. WHAT IS THE ISSUE WITH RESPECT TO SINGLE PHASE VERSUS THREE PHASE CONFIGURATION AND RELATED IMPACTS ON COST ALLOCATION?

A. The Company does not separate the costs of its single-phase primary distribution system from its three-phase primary distribution system. In response to ND-MLEC-131 (Exhibit ___ (KM-1), Attachment 8), the Company responded that it "does not have the system data available to determine the embedded amount of primary distribution system costs that is associated with single phase and three-phase circuits." OTP also indicates in the same response that single phase circuits are used primarily to provide service to secondary voltage customers.

Since the Company does not have the data available to separate out the single-phase and three-phase circuit related costs, it is necessarily over allocating costs related to single-phase distribution to primary voltage customers, which needs to be corrected. This is

because as noted in the Company's response, the single-phase distribution equipment is used primarily to provide service to secondary voltage customers.

Q. WHAT DO YOU RECOMMEND?

A. While it would be preferable to make these corrections in the current case, the Company does not seem to have the information necessary to make these corrections. Therefore, I recommend that in the next rate case, the Company be required to separate out the single-phase and three-phase related circuit costs and properly allocate these distribution costs to the customers for which they are incurred.

C. Revenue Apportionment

Q. WHAT IS THE COMPANY'S PROPOSAL FOR REVENUE APPORTIONMENT TO CLASSES?

A. The Company proposes to allocate the proposed revenue requirement to classes as shown in **Table 3** below for the initial revenue requirement increase of 10.61% (see Gina Ice Direct at Page 12, Table 5). This table also shows the Company's CCOS derived revenue responsibility by class. In support for the proposed increases for each class, Ms. Ice indicates that the Company has moved the classes closer to cost, but has also considered gradualism in proposing the revenue allocation to classes.

Table 3: OTP Revenue Apportionment to Classes With 10.61% Increase

A	B	C	D	E	F	G
	OTP Proposed Revenue Allocation					
Class	Present Revenues	Amount of Increase	Percent Increase	Total Revenue	OTP COS Increase	CCOSS Increase Minus OTP Revenue Allocation
Residential	$48,209,916	$6,604,758	13.70%	$54,814,675	$10,643,028	$4,038,270
Farms	$2,612,688	357,938	13.70%	$2,970,626	$804,687	$446,749
General Service	$38,950,615	3,221,905	8.27%	$42,172,520	$424,321	($2,797,584)
Large General Service	$43,160,710	3,565,075	8.26%	$46,725,785	($1,099,489)	($4,664,564)
Irrigation	$59,083	11,226	19.00%	$70,308	$57,369	$46,144
Lighting	$2,869,144	372,989	13.00%	$3,242,133	$655,804	$282,816
OPA	$1,203,986	156,518	13.00%	$1,360,505	$319,236	$162,717
Controlled Service Water Heating	$1,085,033	148,650	13.70%	$1,233,682	$535,787	$387,138
Controlled Service Interruptible	$8,397,154	1,150,410	13.70%	$9,547,564	$3,237,513	$2,087,103
Controlled Service Deferred	$1,523,622	125,851	8.26%	$1,649,473	$137,064	$11,213
	$148,071,951	$15,715,320	10.61%	$163,787,271	$15,715,320	$0

Q. IS THERE A DIFFERENCE BETWEEN THE CLASS REVENUE RESPONSIBILITY PROPOSED BY THE COMPANY AND CLASS COST RESPONSIBILITY?

A. Yes, there is. In fact, as can be observed in **Table 3**, Column G, there are considerable differences such that the revenue responsibility is significantly below costs for some classes and significantly above costs for other classes. The General Service and Large General Service classes are allocated a share of revenue responsibility much higher than the cost responsibility for each of those classes. That is, these two classes are subsidizing all of the other classes.

Q. WHAT IMPACT DOES OTP'S REVENUE ALLOCATION TO CLASSES HAVE ON THE REVISED REVENUE REQUIREMENT INCREASE OF 6.64%?

A. **Table 4** shows the revenue allocation. Since the Company did not provide additional modifications to its revenue allocation approach in supplemental testimony, I utilized the resulting class revenue responsibility from OTP's proposal in direct testimony to arrive at the increases by class. For ease of reference, I provide the proposed revenue responsibility share in Column F in **Table 4** below. I utilized these percentage shares to calculate the revenue responsibility shares in Column E. Columns C and D were derived by comparing the proposed class revenue responsibility (Column E) to class present revenues (Column B).

Table 4: OTP Revenue Apportionment to Classes with 6.64% Increase

A	B	C	D	E	F	G
	OTP Proposed Revenue Allocation					
Class	Present Revenues	Amount of Increase	Percent Increase	Total Revenue	OTP Proposed Revenue Responsibility - Direct Testimony	OTP COSS Increase Minus OTP Proposed Increase
Residential	$47,632,359	$4,570,743	9.60%	$52,203,102	33.47%	$3,677,381
Farms	$2,573,882	$255,213	9.92%	$2,829,095	1.81%	$399,814
General Service	$38,487,308	$1,675,959	4.35%	$40,163,266	25.75%	-$2,684,950
Large General Service	$42,613,778	$1,885,818	4.43%	$44,499,597	28.53%	-$4,256,767
Irrigation	$58,520	$8,439	14.42%	$66,959	0.04%	$41,964
Lighting	$2,841,429	$246,237	8.67%	$3,087,665	1.98%	$235,254
OPA	$1,188,731	$106,954	9.00%	$1,295,685	0.83%	$153,495
Controlled Service Water Heating	$1,074,543	$100,362	9.34%	$1,174,905	0.75%	$354,298
Controlled Service Interruptible	$8,296,431	$796,252	9.60%	$9,092,683	5.83%	$2,057,602
Controlled Service Deferred	$1,506,746	$64,141	4.26%	$1,570,886	1.01%	$21,909
	$146,273,726	$9,710,117	6.64%	$155,983,843	100.00%	$0

Q. DO YOU SUPPORT OTP'S REVENUE ALLOCATION?

A. No. While I appreciate the Company's movement towards its CCOS results, I believe that more movement towards cost is required. It is important to not lose sight of the fact that while some customers' classes will continue to contribute significantly less than their share of costs under the Company's proposed approach, other classes are being asked to bear the unfair burden of contributing more than their share of costs. For example, for the LGS class, OTP's CCOS shows that with a system wide increase of 6.64%, the LGS class should get a 5.56% decrease. Instead, OTP's proposal would result in a 4.43% increase. That is, the LGS class is being asked to continue to significantly pay toward other classes' under contributions toward cost. Such a result puts the LGS class in a tenuous position and does not seem equitable or reasonable particularly when OTP's average industrial rate is not competitive when compared to regional and national averages.

As discussed earlier, declining rate competitiveness from a relative standpoint puts industrial load at risk of shutting down facilities in OTP's territory, shifting production elsewhere or choosing bypass options such as distributed generation. Implementation of any of these options would result in unfavorable circumstances for remaining customers – residential, commercial and industrial, who would face larger increases.

Q. IS THE COMPANY'S CURRENT CCOSS METHODOLOGY ALREADY MODERATING THE RATE IMPACT TO CERTAIN CLASSES?

A. Yes, the Company's approach for classifying fixed production plant costs is punitive to energy intensive or high load factor classes such as the LGS class and is already moderating the impacts to lower load factor classes such as the residential class. This is further demonstrated by comparing the results for the LGS class in **Table 1** (Company's CCOSS results) v. (MLEC CCOSS) in **Table 2**. The Company's CCOSS shows a decrease of 5.56% for the LGS class while the MLEC CCOSS shows a decrease of 11.16%, double that of OTP's CCOSS result for the LGS class.

Q. WHAT IS YOUR RECOMMENDATION?

A. Given that OTP's CCOSS approach already considers gradualism, it can be argued that the class revenue responsibility should align perfectly with the class cost responsibility derived from the Company's CCOSS. That being said, I recognize that additional gradualism may be desired to moderate the impact for other classes albeit not to the extent proposed by the Company.

My recommendation is to bring each class closer to the Company's CCOSS than the Company's proposal. The results are shown in **Table 5**.

Table 5: MLEC Revenue Apportionment to Classes with 6.64% Increase

A	B	C	D	E	F	G	H	I
		MLEC Proposal						
Class	Present Revenues	Revenue Allocation	Percent Increase	Total Revenue Responsibility	OTP CCOS Results	OTP CCOS Increase Minus MLEC Recommended Increase	MLEC Resulting Revenue Responsibility	OTP CCOSS Responsibility Share
Residential	$47,632,359	$5,239,560	11.00%	$52,871,919	$55,880,483	$3,008,564	33.9%	35.8%
Farms	$2,573,882	$283,127	11.00%	$2,857,009	$3,228,908	$371,900	1.8%	2.1%
General Service	$38,487,308	$1,525,959	3.96%	$40,013,266	$37,478,316	-$2,534,950	25.7%	24.0%
Large General Service	$42,613,778	$717,680	1.68%	$43,331,458	$40,242,829	-$3,088,629	27.8%	25.8%
Irrigation	$58,520	$8,778	15.00%	$67,298	$108,922	$41,625	0.0%	0.1%
Lighting	$2,841,429	$312,557	11.00%	$3,153,986	$3,322,919	$168,933	2.0%	2.1%
OPA	$1,188,731	$130,760	11.00%	$1,319,492	$1,449,181	$129,689	0.8%	0.9%
Controlled Service Water Heating	$1,074,543	$161,181	15.00%	$1,235,724	$1,529,203	$293,479	0.8%	1.0%
Controlled Service Interruptible	$8,296,431	$1,244,465	15.00%	$9,540,895	$11,150,285	$1,609,389	6.1%	7.1%
Controlled Service Deferred	$1,506,746	$86,050	5.71%	$1,592,796	$1,592,796	$0	1.0%	1.0%
	$146,273,726	$9,710,117	6.64%	$155,983,843	$155,983,843	$0		

I considered gradualism as well. I also note that the LGS class responsibility share continues to be significantly greater than the Company's OTP CCOSS share even under my recommended revenue allocation approach. Further, even though the residential and related class increases (such as controlled water heating) range from 11% to 15%, such an increase would still result in their rates being below the regional and national averages. As I mentioned earlier, OTP's North Dakota average residential rate is 25% and 31% below the regional and national averages.

Q. WHAT IS YOUR RECOMMENDATION FOR REVENUE ALLOCATION FOR THE FINAL INCREASE?

A. I urge the Commission to take meaningful steps to get each class closer to cost using the OTP CCOSS in this proceeding. At a minimum, I recommend that the revenue responsibility shares shown in Column H of **Table 5** be applied to calculate the revenue responsibility by class.

D. Rate Design

Q. WHAT ISSUES DO YOU PLAN TO ADDRESS IN THIS SECTION OF YOUR TESTIMONY?

A. While the section on revenue apportionment dealt with inter-class issues (i.e.: among classes like Residential or LGS), this section addresses intra-class (i.e.: among different sub rate classes within the LGS class) issues. I will address the following in this section:

- Importance of accurate pricing signals.
- Evaluation and subsequent recommendations regarding the Company's proposed revenue apportionment within the class and related rate design charges.

1. Importance of Pricing Signals

Q. WHY IS IT IMPORTANT FOR RETAIL RATES TO REFLECT ACCURATE PRICING SIGNALS?

A. Retail rates reflect the pricing signals to customers and are used by utilities to recover costs. It is important for retail rates to reflect accurate pricing signals because they drive consumer behavior, which in turn result in more efficient use of the system thereby minimizing system costs. Provided that rates reflect costs to serve, there is equitable recovery of costs from customers within the classes and customers have the proper pricing signals and incentives. However, if rates are misaligned with costs to serve, not only does this result in inequity amongst customers within the class, but also provides misleading signals which ultimately raises costs for all customers.

Q. DOES THE COMPANY'S PROPOSAL GENERALLY ALIGN CLOSELY WITH EMBEDDED COSTS TO SERVE WITHIN THE CLASS?

A. I don't know. This is because the Company does not appear to have embedded cost information by sub rate classes. All of the information regarding sub rate classes is based on marginal costs. In this regard, I recommend that OTP provide embedded cost information by sub class in its next base rate case proceeding. While the marginal cost study can be utilized to fine tune the pricing signals, the embedded cost information should be used to ensure that each sub class' rates are being designed to cover the

embedded cost for each sub class. MLEC witness Larry Schedin provides more detail regarding this matter in his testimony.

2. Proposed Revenue Apportionment Within the LGS Class

Q. WHAT IS THE COMPANY'S PROPOSED APPROACH REGARDING REVENUE ALLOCATION WITHIN THE LGS CLASS?

A. Company witness Prazak uses the proposed revenue apportionment of $3.565 million or 8.27% to allocate the increases within the LGS class. The 8.27% increase for the LGS class recommended by OTP witness Gina Ice in her direct testimony for a system wide increase of 10.61%. Mr. Prazak uses the marginal cost study to allocate costs within the LGS class. He testifies that he applied a modified equal marginal percent of marginal cost (EMPC) methodology. Based on a review of witness Prazak's description of the method used, it is my understanding that for the LGS class, the Company generally uses a combination of the differences between the marginal cost revenues and the proposed increase for the class, for revenue allocation purposes.

Q. DID MR. PRAZAK PROVIDE UPDATED SCHEDULES TO REFLECT THE REVISED REVENUE REQUIREMENT INCREASE OF 6.64% IN SUPPLEMENTAL TESTIMONY?

A. No. In order to enable an apples-to-apples comparison with Mr. Prazak's proposed rate design specifics, I provide recommendations based on the 8.27% increase to the LGS class.

Q. WHAT ARE THE SUB CLASSES IN THE LGS CLASS?

A. The Company has the following sub classes:

- LGS Secondary
- LGS Primary and RTP Rider
- LGS Transmission
- LGS Secondary Time of Day
- LGS Primary Time of Day
- LGS Transmission Time of Day

- Standby Rider

At the present time, almost all of the customers are on the LGS Secondary and LGS Primary and RTP Rider sub classes respectively. OTP has one customer on the LGS Secondary Time of Day and one customer on the Standby Rider. I focused my efforts on evaluating the rate design issues related to the LGS Secondary and LGS Primary sub classes (non-time of day).

Q. WHAT IS THE COMPANY'S REVENUE ALLOCATION PROPOSAL TO THE LGS SECONDARY AND LGS PRIMARY CLASSES?

A. Mr. Prazak's corrected proposal submitted in supplemental testimony shows an increase of $2,908,123 or 7% increase for the LGS Secondary and LGS Primary (without RTP Rider) classes respectively.

Table 6: OTP Proposed Allocation to LGS Secondary and Primary Classes

	Present Rate Revenues	Proposed Rate Revenues	Increase
LGS Secondary	$31,657,902	$33,871,743	7.0%
LGS Primary	$9,924,239	$10,618,459	7.0%
	$41,582,140	$44,490,202	7.0%

Q. WHAT ARE YOUR COMMENTS ON THIS PROPOSAL?

A. I believe that the rate increase for the LGS Primary class should be lower compared to the LGS Secondary class because the Company's Equal Percent Marginal Cost (EPMC) analysis shows that the LGS Primary sub class is more efficient than the LGS Secondary sub class (see Attachment 1 to ND-MLEC-120) (Exhibit ___ (KM-1), Attachment 9). Further, the rate design also needs to properly account for the differentials between primary and secondary voltage service levels.

Q. WHAT ARE THE DEMAND CHARGE DIFFERENTIALS BETWEEN THE LGS PRIMARY AND SECONDARY CLASS?

A. **Table 7** shows the differential between the marginal and OTP proposed demand charges on a seasonal and annualized basis. As the table shows, the marginal cost study showed

an annualized differential of $0.66/KW-month compared to OTP's proposed $0.13/kW-month

Table 7: OTP Proposed Demand Charge Differentials by Primary v. Secondary

	Summer	Winter	Annual	% OTP/Marginal Cost
LGS Secondary				
Demand Charges - Marginal	$25.28	$10.41	$15.37	
OTP Demand Charges	$11.33	$8.33	$9.33	61%
LGS Primary				
Demand Charges - Marginal	$24.29	$9.91	$14.70	
OTP Demand Charges	$11.06	$8.27	$9.20	63%
Secondary - Primary				
Differential based on Marginal Cost	$0.99	$0.50	$0.66	
Differential based on OTP Prop.	$0.27	$0.06	$0.13	20%

Q. WHAT ARE THE ENERGY CHARGE DIFFERENTIALS BETWEEN THE LGS PRIMARY AND SECONDARY CLASS?

A. **Table 8** shows the differential between the marginal and OTP proposed energy charges on a seasonal and annualized basis. As the table shows, the marginal cost study showed an annualized differential of $0.001/kWh compared to OTP's proposed $0.0002/kWh.

Table 8: OTP Proposed Energy Charge Differentials by Primary v. Secondary

	Summer	Winter	Annual	
LGS Secondary				
Energy Charges - Marginal	$0.02611	$0.02674	$0.0265	
OTP Energy Charges	$0.02907	$0.02977	$0.0295	111%
LGS Primary				
Energy Charges - Marginal	$0.02527	$0.02572	$0.0256	
OTP Energy Charges	$0.02896	$0.02947	$0.0293	115%
Secondary - Primary				
Differential based on Marginal Cost	$0.00084	$0.00102	$0.0010	
Differential based on OTP Prop.	$0.00011	$0.00030	$0.0002	25%

Q. WHAT IS YOUR INITIAL RECOMMENDATION?

A. I recommend that the Company revise its proposal to include a higher than proposed voltage level discount for energy and demand charges for the LGS primary class. From a preliminary perspective, I recommend a $.40/KW-month demand charge discount and a $0.0006/kWh energy charge discount for the LGS Primary class. These charges are the average of the annualized differentials of the marginal cost study and OTP's current proposal. In this regard, it would also be very helpful to know the embedded cost differentials as recommended by MLEC witness Larry Schedin. I will provide final recommendations regarding this matter in following rounds of testimony after the Company has the opportunity to respond.

Q. WHAT IS THE RESULTING REVENUE ALLOCATION TO THE LGS SECONDARY AND LGS PRIMARY CLASS CHANGE AFTER INCORPORATING THE VOLTAGE LEVEL DEMAND AND ENERGY DISCOUNTS YOU RECOMMENDED ABOVE?

A. **Table 9** provides the resulting revenue allocation based on the same total revenue requirement increase to the LGS Secondary and LGS Primary sub classes without RTP rider as shown in the OTP proposal in **Table 6** above. (Exhibit ___ (KM-1), Attachment 10) shows more details behind the calculations.

Table 9: MLEC Proposed Revenue Allocation for Secondary v. Primary LGS Sub Class

	Present Revenues	MLEC Proposed Increase Using OTP Proposed Allocation to LGS Class	MLEC Proposed Increase	MLEC Proposed Increase
LGS Secondary	$31,657,902	$33,972,621	$2,314,719	7.3%
LGS Primary	$9,924,239	$10,517,642	$593,403	6.0%
	$41,582,140	$44,490,263	$2,908,123	7.0%

Q. WHAT ARE THE PROPOSED STRUCTURAL CHANGES TO THE LGS SECONDARY AND PRIMARY RATES?

A. OTP proposes to eliminate the declining block energy rate structure for the LGS class. Instead, the Company proposes a single energy rate differentiated by season. Demand

charges are also differentiated by season. OTP has substantially increased the demand charges compared to existing rates, while comparatively lowering the energy charges.

Q. DO YOU SUPPORT THESE CHANGES?

A. I support the Company's proposal to increase the demand charges while reducing the energy charges. This approach is consistent with OTP's cost drivers in this case which are primarily related to increases in fixed costs associated with infrastructure and fixed O&M expenses. Given these cost drivers, demand charges should be significantly increased and energy charges should be correspondingly decreased.

Q DO YOU HAVE ADDITIONAL CONSIDERATIONS FOR THE COMMISSION TO CONSIDER?

A. In advance of the next rate case, MLEC would like to work with the Company to investigate further enhancing the rate design for the LGS class in addition to the foregoing recommendations. The goal would be to optimize and balance the objectives of customer acceptability and understanding, rate efficiency and mitigating cross subsidization. This study would include and not be limited to:

- Costing out embedded costs to serve by sub rate class;
- Analyzing the relationship between embedded and marginal costs; and
- Investigation of simplifying TOD rate design and evaluating option of introducing high load factor credits.

In Rebuttal testimony, I would appreciate feedback regarding the Company's interest in pursuing these matters in advance of the next rate case. I note that the Company agreed to work with the Minnesota Chamber of Commerce regarding these issues in advance of its next rate case in Minnesota.

E. Super LGS Rate

Q. WHAT IS THE PROPOSED ELIGIBILITY CRITERIA FOR THE SUPER LGS RATE?

A. The Company's proposal consists of making this rate available to new customers that have an expected metered demand of at least 25 MW at a single metering point, a minimum load factor of 80% at annual energy sales of at least 175,000 MWhs.

Q. HOW DOES THE COMPANY PROPOSE TO CALCULATE THE CHARGES FOR THIS RATE?

A. Mr. Prazak indicates in his direct testimony on page 61 that the charges will be based on marginal costs meaning that the rate will need to cover the marginal costs associated with transmission, distribution, generation and customer services.

Q. WILL CUSTOMERS ON THIS RATE PAY CHARGES ASSOCIATED WITH MANDATORY RIDERS (TCR, RER, ETC.)?

A. Yes, according to the proposed tariff schedule, customers will pay these charges. Thus, at a minimum, customers on this rate will be contributing to fixed costs through these riders thereby reducing costs for all customers.

Q. WHAT IS YOUR GENERAL GUIDANCE REGARDING THE INTRODUCTION OF THE SUPER LGS RATE AND THE ECONOMIC DEVELOPMENT RIDER?

A. Generally speaking, if rates were closely aligned with a proper CCOSS, the Company would likely not require such rates. It is worth noting that the Super LGS rate, along with the Economic Development Rider rate are both designed to attract high load factor customer growth. The Company noted in the Economic Development Rate (EDR) filing in docket PU-17-328, that attracting high load factor growth from current or new businesses has the effect of "increasing Otter Tail's system average load factor, which positively impacts (lowers) the unit costs and puts downward pressure on rates for existing customers at the next rate case." Thus, the CCOSS and related revenue allocation should strongly consider the benefits of the high load factor customer classes such as the LGS class

Q. PLEASE COMMENT ON THE SPECIFICS OF OTP'S PROPOSED SUPER LGS RATE.

Since the potential contract rate covers the marginal costs and assigns costs of mandatory riders, it should cover the costs of service plus provide contribution to fixed costs especially through the mandatory rider charges.

Q. DO YOU HAVE ANY RECOMMENDATIONS REGARDING THE SUPER LGS RATE?

A. Yes, I do. I have two recommendations:

First, I recommend an initial MW cap for this rate. Since new customers on this rate can be served on firm service, the cap should be based on the amount of surplus generation capacity the Company expects to have, after building the Astoria plant. The surplus capacity from Astoria can be maximized through this rate offering.

Second, instead of an indefinite term, I recommend an initial term of 10 years.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Kavita Maini, KM Energy Consulting, LLC - Project Experience

	Docket Number	Type by State/FERC	Major Issues	Role
	Retail Jurisdiction			
		North Dakota		
1	PU-05-131	Otter Tail: Cost of Energy Adjustment Clause	Time of use rate related issues	Expert Witness - Large Industrial Group
2	PU-08-862	Otter Tail: Base Rate Case Application	Revenue Requirement, rate design	Expert Witness - Large Industrial Group
3	PU-08-742	Otter Tail: Renewable Resource Cost Recovery Rider	Revenue Requirement, cost allocation and rate design	Expert Witness - Large Industrial Group
4	PU-11-153;162	Otter Tail: Transmission Cost Recovery Rider	Revenue Requirement, cost allocation and rate design	Expert Witness - Large Industrial Group
5	PU-17-398	OTP Base Rate Case Application	In Progress	Expert Witness - Large Industrial Group
		South Dakota		
6	EL11-019	Xcel Energy Base Rate Case Application	Renewable related revenue requirements	Expert Witness - PUC Staff
7	EL12-027, EL14-082	Otter Tail Petition to Establish an Environmental Quality Cost Recovery Tariff	Evaluation of Big Stone AQCS as a least cost resource	Expert Witness - PUC Staff
8	EL12-062	Black Hills Phase In - Cheyenne Prairie Generating Station	Evaluation of a Combined Cycle Addition - Need and least cost resource	Expert Witness - PUC Staff
9	EL14-058	Xcel Energy Base Rate Case Application	Least cost resource evaluation and related revenue requirements	Expert Witness - PUC Staff
10	EL15-024	MDU Base Rate Case Application	Least cost resource evaluation and related revenue requirements	Expert Witness - PUC Staff
11	EL-021	Complaint filed by Juhl Energy AKA Consolidated Edison regarding avoided cost compensation for wind QFs	Methodology for Avoided Cost	Expert Witness - PUC Staff
12	EL16-037	Commission Staff Motion to Show Cause regarding certain fuel cost recovery through the Fuel Cost Recovery Rider	Prudency of Acquiring Resources	Expert Witness - PUC Staff
		Minnesota		
13	E002/GR-13-868	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Expert Witness - MN Chamber
14	ER017/GR12-961	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Expert Witness - MN Chamber
15	E017/GR08-1065	Otter Tail Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
16	E002/GR07-1178	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
17	E002/GR10-971	Xcel Energy Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
18	E001/GR-10-276	Interstate Power & Light Base Rate Case Application	Revenue Req., Class Cost of Service Study and Rate Design	Technical Support - MN Chamber
19	E-017/M-08-1529	Otter Tail: Renewable Resource Cost Recovery Factor	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
20	E-017/GR09-881	Otter Tail: Transmission Cost Recovery Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
21	E-017/M-09-1484	Otter Tail: Renewable Resource Cost Recovery Factor	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
22	E017/M-10-1061	Otter Tail:Transmission Cost Recovery Rider Annual Adjustment	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
23	E-017/M-10-220	Otter Tail: Update Conservation Improvement Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
24	E017/M-12-179	Otter Tail: Petition to include CSAPR related costs in FCA	Revenue Requirements	Lead Expert - MN Chamber
25	E017/M-12-708	Otter Tail: Renewable Resource Cost Recovery Factor	Cost Allocation and Rate Design	Lead Expert - MN Chamber
26	E002/M-10-1064	Xcel Energy: Transmission Cost Recovery Rider	Revenue Requirements, Cost Allocation and Rate Design	Lead Expert - MN Chamber
27	E002/M-10-1066	Xcel Energy: Renewable Energy Standard Cost Recovery Rider	Cost Allocation and Rate Design	Lead Expert - MN Chamber

Kavita Maini, KM Energy Consulting, LLC - Project Experience

	Docket Number	Type by State/FERC	Major Issues	Role
28	MPUC DOCKET NO. E002/M-11-278;MPUC DOCKET NO. E001/M-11-244;MPUC DOCKET NO. E015/M-11-241	Investor owned utilities CIP filings	Class Allocation and Rate Design	Lead Expert - MN Chamber
29	E, G-999/CI-08-133	Review of Financial Incentive Mechanism for CIP Programs	Avoided Costs, Policy Issues	Lead Expert - MN Chamber
30	E-999/CI-11-852	Renewable Energy Cost Impacts	Cost Effectiveness of Implementing Renewable Energy Standard	Lead Expert - MN Chamber
31	E017/RP-10-623	Otter Tail: Integrated Resource Plan	Resource Planning	Lead Expert - MN Chamber
32	E017/RP-10-623	Otter Tail: Hoot Lake Baseload Diversification Study	Resource Planning	Lead Expert - MN Chamber
33	E002/RP-10-825	Xcel Energy:Integrated Resource Plan	Resource Planning	Lead Expert - MN Chamber
34	E015/RP-13-53	Minnesota Power - Integrated Res. Plan	Resource Planning	Lead Expert - MN Large Industrial Group
35	E999/AA-12-757	Fuel Cost Recovery -All Utilities	Policy Issues	Lead Expert - MN Chamber
30	E017/M-14-201	OTP CIP Filing	Policy Issues	Lead Expert - MN Chamber
31	E017/RP-13-961	OTP IRP Filing	Resource Planning	Lead Expert - MN Chamber
32	ER002/GR-15-826	Xcel Energy Base Rate Case Application	Revenue Requirement/CCOSS	Expert Witness - MN Chamber (Proceeding in progress)
33	ER17/GR-15-1033	Otter Tail Base Rate Case Application	Revenue Requirement/CCOSS	Expert Witness - MN Chamber (Proceeding in progress)
34	E-999/CI-03-802	Fuel Cost Reform- All Utilities	Policy Issues	Technical Comments - MN Chamber
35	E002/M-16-777	Xcel Wind Portfolio	Revenue Requirement Issues	Technical Comments - MN Chamber
36	E, G999/CI-17-895	Tax Reform	Recommendations regarding TCJA related savings (in progress)	Technical Comments - MN Chamber
		Wisconsin		
37	05-ES-103	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
38	05-ES-104	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
39	05-ES-105	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
40	05-ES-106	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
41	05-ES-107	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
42	05-ES-108	Strategic Energy Assessment	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
43	05-EI-141	Planning Reserve Margin Requirements	Resource Planning	Technical Comments - On behalf of Wiconsin Industrial Energy Group (WIEG) et al
44	05-EI-148	Advanced Renewable Tariffs	Rates	Technical Comments on behalf of WIEG
45	05-UI-113	Cost allocation associated with Energy Efficiency Programs	Cost Allocation	Technical Comments on behalf of WIEG
46	05-UI-114	Innovative Ratemaking	Rate Design	Technical Comments on behalf of WIEG
47	05-UI-115	Quadrennial Planning Process - Energy Efficiency	Policy Issues	Technical Comments - On behalf of WIEG et al
48	05-UI-116	Demand Response and ARC Participation	Policy Issues	Technical Comments on behalf of WIEG
49	9300-EI-100	Impacts or Activities related to MISO	Policy Issues	Technical Comments on behalf of WIEG
50	05-EI-150	Review Potential Excess Capacity in WI	Policy Issues	Technical Comments - On behalf of WIEG et al
51	6680-GF-126	Wisconsin Power & Light:Experimental Economic Development Rider	Rate Design	Technical Comments on behalf of WIEG
52	6630-GF-134	We Energies: RTMP Rate	Rate Design	Technical Comments on behalf of WIEG
53	3270-UR-117	Madison gas & Electric: SP3 Rate Changes	Rate Design	Technical Comments on behalf of WIEG
54	6680-GF-130	Application of ED Rider by Mercury Marine	Rate Design	Technical Comments on behalf of WIEG
55	1-AC-234	Renewable Resource Credit Rule Revisions after 2009 Wisconsin Act 406	Policy Issues	Technical Comments - On behalf of WI Ind. Associations
56	05-EI-137	Class Cost of Service and Rate Design	Policy Issues	Technical Comments on behalf of WIEG

Kavita Maini, KM Energy Consulting, LLC - Project Experience

	Docket Number	Type by State/FERC	Major Issues	Role
57	05-FE-100	Quadrennial Planning Process - Energy Efficiency	Policy Issues	Technical Comments - On behalf of WIEG/WPC/WMC
58	6630-BS-100	Presque Isle - WEPCO/Wolverine Transaction	Policy Issues	Technical Comments on behalf of WIEG
59	05-UR-107	WEPCO Base Rate Application	Revenue Requirement	Expert Witness - WIEG and CUB
60	6680-UR-120	WP&L Base Rate Application	CCOSS, Rate Design and Revenue Allocation	Expert witness on behalf of WIEG
61	6630-FR-106	WEPCO 2017 Fuel Cost Plan	Recommendations for Revenues Related to Excess Capacity	Expert witness on behalf of WIEG
62	05-BS-212 and 05-AI-100	WEC transfer of assets to UMERC and related affiliated interest agreements	Protecting interests of WI customers served by WEC	Comments on behalf of WIEG, WPC and CUB
61	9400-YO-100	Wisconsin Gas Earnings Sharing Mechanism	Refund method	Technical comments of behalf of WIEG and CUB
62	05-AE-208	Affiliated Interest Agreement between WPSC and WEPCO - capacity only transaction	Recommendations for accounting treatment and capacity prices	Technical comments of behalf of WIEG, WPC and CUB
63	5-UR-108	Joint Application of WEPCO, Wisconsin Gas and WPSC for Approvals Related to Settlement Agreement	Revenue Requirement Issues	Expert witness on behalf of WIEG and CUB
64	05-AF-101	TCJA Investigation	Tax Impacts and Related Recommendations	Technical comments of behalf of WIEG, WPC and CUB
65	05-FE-101	Quadrennial Planning Process - Energy Efficiency	Recommendations regarding Cost Effectiveness and Other Aspects	Technical Comments on behalf of Several Wisconsin Industrial Associations
		Sasketchewan		
66	2008	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Expert Witness on behalf of ERCO
67	2010	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Expert witness on Behalf of ERCO and Assistance to SIECA
68	2013	Sask Power Rate Case Application	Revenue Requirements, Class Cost of Service, Rate Design	Technical Consultant to SIECA
		Iowa		
69	WRU-2014-0009-0150	Alliant Energy	Revenue Requirement	Expert Witness on behalf of Department of Justice - Office of Consumer Advocate
		Missouri		
70	ER-2014-0351	Empire District Electric Rate Case	FAC, Class Cost of Service, Rate Design	Expert Witness on behalf of MO Energy Consumers Group
71	ER-2016-0023	Empire District Electric Rate Case	Class Cost of Service, Rate Design	Expert Witness on behalf of MO Energy Consumers Group
	FERC Dockets			
72	ER07-1372	Integrating Ancillary Services into Energy Markets	Market Design and Policy Issues	Joint Protest; Midwest Industrial Customers
73	ER08-394	Resource Adequacy	Market Design and Policy Issues	Joint Protest; Midwest Industrial Customers
74	ER08-404	Schedule 30 - Emergency Demand Response	Compensation/Design/Policy	Joint Protest; Midwest Industrial Customers
75	RM07-19-0000 and AD07-7-0(	Effective Competition in Wholesale Markets	Market Design and Policy Issues	Joint Protest; Wisconsin Industrial Energy Group
76	ER10-1791-000	Multi Value Projects - Transmission	Cost Allocation and Rate Design	Joint Protest; Wisconsin Industrial Energy Group
77	ER11-4337-000	MISO's Order 745 Compliance Filing	Cost Allocation and Other Policy Issues	Joint Protest; Wisconsin Industrial Energy Group
78	ER13-37-000 and ER13-38-00(	System Support Resource	Cost Allocation and Other Policy Issues	Joint Protest;MN Industrial Group, Wisconsin Industrial Energy Group and Wisconsin Paper Council
79	RM10-23-000	Transmission Planning and Cost Allocation	Planning and Policy	Joint Protest; Wisconsin Industrial Energy Group
80	ER13-76,ER13-1962	System Support Resource	Cost Allocation and Other Policy Issues	Joint Protest;MN Industrial Group, Wisconsin Industrial Energy Group and Wisconsin Paper Council
81	ER14-1242-000 and ER14-243	System Support Resource	Cost Allocation and Other Policy Issues	Joint Comments - Wisconsin Industrial Energy Group and Citizens Utility Board
82	EL14-34-000	WI Commission Complaint regarding Cost Allocation associated with WEPCO's Presque Isle System Supply Resource	Cost Allocation	Joint Comments (Wisconsin Industrial Energy Group and Citizens Utility Board)
83	E:16-1-000	Petition for Waiver by Heartland Consumers Power District on behalf of itself and of its customers for waivers of Section 292.402 obligations	Primarily lack of standby power provisions	Comments developed in conjunctions with another consultant and Soybean Food Processors

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/25/2018
Responding Witness: Tyler A. Akerman, Manager, Business Planning Regulatory Accounting - (218) 739-8298

Data Request:

Provide the excess accumulated deferred income taxes (ADIT) by FERC account/subaccount and temporary difference. If not evident by the account/subaccount description, provide a description of the temporary difference.

a. For each temporary difference identified in response to this question, indicate whether the Company believes the related ADIT is protected or unprotected. Other than for ADIT due to accelerated tax depreciation, if the Company believes that the ADIT is protected, provide all citations to the IRC, Regulations, Private Letter Rulings, and all other authoritative sources that support the Company's position.

b. For each temporary difference identified in response to this question as protected, provide the projected amortization and the underlying calculations for the Test Year consistent with the reversal of the underlying temporary difference and consistent with the ARAM. Provide these amounts on a total company and jurisdictional basis.

c. For each temporary difference identified in response to this question as unprotected, provide the projected amortization of the excess ADIT, the revenue equivalent, and the underlying calculations for 2018 and 2019 consistent with the reversal of the underlying temporary difference. Provide these amounts on a total company and jurisdictional basis.

Attachments: 1

Attachment 1 to DR ND-MLEC-141.pdf

Response:

a. See Attachment 1 to DR ND-MLEC-141 for a listing of temporary items by FERC account for year-end 2017. The only temporary items listed that we consider to be protected are related to excess tax over book depreciation, which includes ($106,177,537) in account 282 and ($1,623,952) in account 281.

b. Otter Tail uses the PowerTax system to track and calculate the reversal of ADIT balances related to property. Due to the amount of information used and the fact that the reversal of ADIT is dependent on each year's book versus tax activity, it is difficult to forecast the exact amount these balances will reverse each year.

   Based upon our 2017 Technical update to the annual depreciation filing, we have estimated the average life of property to be 25 years. Using this average life, we estimate the reversal of protected ADIT to be approximately $4,312,000 ($106,177,537 plus $1,623,952 equals $107,802,489 divided by 25 years).

c. Each unprotected temporary item listed in Attachment 1 to DR ND-MLEC-141 is unique. The reversing of the deferred is dependent on each year's activity related to that temporary item and the time could range from one year to over 30 years. Due to the number of unprotected items and the complexity of the items, it is difficult to estimate how the excess ADIT balances will reverse.

Due to the fact that the unprotected items total only ($930,203) of the total excess ADIT balance of $108,731,692, we suggest the unprotected items are treated the same as the protected items with the same amortization schedule, to be reversed using ARAM. This would follow the actual activity related to each item for tax accounting. Assuming a 25-year life, the amortization would equal only $37,208 annually ($930,203 divided by 25 years).

The revenue requirement for these unprotected temporary items would include a gross up amount, the gross up factor subsequent to tax reform equals 1.32284 resulting in a total revenue requirement of $1,230,510 or $49,220/annually ($1,230,510 divided by 25 years).

Based upon our most current cost of service for North Dakota, North Dakota's allocation factor is .36086122. This results in $335,674 of the $903,203 unprotected balance would be allocated to North Dakota customers.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/30/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please provide the calculations of the revenue requirements associated with CISone. Please provide a narrative explanation and provide the calculations in Excel spreadsheet format with formulae intact.

Attachments: 1

Attachment 1 to DR ND-MLEC-138.xlsx

Response:

Please see Attachment 1 to DR ND-MLEC-138 for the revenue requirement calculation of the CISone project in Excel format.

Case No. PU-17-398
Attachment 1 to DR ND-MLEC-138
Page 1 of 1

Calculation of CISone Annual Revenue Requirement

Line No.		OTP Total	OTP ND
1	13 Month Average Plant-in-Service (see TY-01)	$7,966,359	$3,272,485
2	13 Month Average Accumulated Depreciation (see TY-01)	(1,356,178)	(557,102)
3	Net Plant-in-Service	$6,610,181	$2,715,383
4	Revenue Requirement @ 7.92% ROR	523,526	$215,058

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 04/10/2018
Date Due: 04/24/2018
Date of Response: 04/30/2018
Responding Witness: Stuart Tommerdahl, Manager, Regulatory Administration, 218 739-8279

Data Request:

Please provide the retirement date, revenue requirement detail for the next five years and a projection of the costs and savings associated with the Hoot Lake plant retirement. Please provide a narrative explanation and quantitative data in live Excel spreadsheet format.

Attachments: 1

Attachment 1 to DR ND-MLEC-134.xlsx

Response:

OTP projects that Hoot Lake Plant will be retired in the second quarter of 2021. For purposes of the revenue requirement calculation OTP provides Attachment 1 to DR ND-MLEC-134 for 2018 through the estimated retirement date. The estimated revenue requirement on the plant balance is determined by applying the rate base revenue requirement factor of 9.67 percent, computed as shown in the *data* worksheet of Attachment 1 to DR ND-MLEC-134. For the purposes of this analysis we excluded fuel expense as those costs are a function of the dispatch and actual operation of the plant and recovered through the energy adjustment rider.

Otter Tail Power Company
Estimated Annual Revenue Requirements for Hoot Lake Plant
2018 - 2021

Hoot Lake Plant	**12/31/2018**	**12/31/2019**	**12/31/2020**	**5/31/2021****
Rate Base	$ 12,131,729	$ 8,835,946	$ 5,488,860	$ 4,094,240
Rate Base Revenue Requirement Factor	9.67%	9.67%	9.67%	9.67%
Rate Base Revenue Requirement	$ 1,173,138	$ 854,436	$ 530,773	$ 395,913
Expenses*	$ 11,527,308	$ 11,370,701	$ 11,379,301	$ 9,426,833
Total Revenue Requirement (OTP Total)	$ 12,700,446	$ 12,225,137	$ 11,910,073	$ 9,822,746
Total Revenue Requirement (OTP ND)	$ 4,625,806	$ 4,452,687	$ 4,337,933	$ 3,577,679

*O&M, Property Taxes, Book Depreciation

**This is the estimated retirement date. Activities for decommissioning the plant are scheduled following the retirement

OTTER TAIL POWER COMPANY
REVENUE REQUIREMENT FACTOR
To be used when estimating revenue requirement on Rate Base Amount Changes

		ND			
1	**Tax Rate**	24.4049%			
2					
3	**Capital Structure**	Rate	Ratio	Cost	Weighted Debt Cost
4	LT Debt	5.2944%	47.50%	2.5100%	5.29%
5	ST Debt	0.0000%	0.00%	0.0000%	
6	Common Equity	10.3000%	52.50%	5.4100%	
7	Required Rate of Return			7.9200%	
8	Equity Return Tax RR (5.41% Equity X Gross up 1.32) - 5.41% Equity)			1.7500%	
9	**Rate Base Revenue Requirement Factor**			**9.6700%**	
10					
11					
12	Gross Up Factor	1.322837	Gross Up of Equity %	7.16%	
13		1 / (1 - Tax Rate)	Equity %	5.41%	
14			Difference	1.75%	
15					

Expenses	**2018**	**2019**	**2020**	**2021**
Operating Costs	$ 6,904,226	$ 6,904,226	$ 6,904,226	$ 6,904,226
Book Depreciation	$ 3,495,094	$ 3,338,487	$ 3,347,087	$ 1,394,620
Property Tax	$ 1,127,988	$ 1,127,988	$ 1,127,988	$ 1,127,988
Total Expenses	$ 11,527,308	$ 11,370,701	$ 11,379,301	$ 9,426,833

OTP ND Share	36.42%
Base Demand Factor	81.73%
Peak Demand Factor	18.27%
ND share - E1 factor	35.66%
ND share - D1 factor	39.84%

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 05/03/2018
Date Due: 05/17/2018
Date of Response: 05/15/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

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Data Request:

Please provide the estimated rate base components for month ending September 2018 for Langdon and Ashtabula in Excel spreadsheet format with formulae intact.

Attachments: 1

Attachment 1 to DR ND-MLEC-150.xlsx

Response:

OTP provides Attachment 1 to DR ND-MLEC-150.

	September 2018 Month End Balances	
RATE BASE (OTP Total)	***Langdon***	***Ashtabula***
Plant Balance - Langdon	$ 79,549,595	$ 116,243,549
Accumulated. Depreciation	$ (33,625,018)	$ (45,970,932)
Net Plant in Service	$ 45,924,577	$ 70,272,617
Inventory	$ 299,793	$ 572,482
Accum. Deferred Inc. Taxes - Fed & State*	$ (18,135,933)	$ (28,144,955)
Accum. Deferred Inc. Taxes - Federal PTC	$ 5,202,956	$ 31,365,714
Accum. Deferred Inc. Taxes - ND ITC	$ 0	$ 17,626,522
Accum. Deferred Inc. Taxes - Fed. portion of ND ITC	$ (0)	$ (6,169,283)
Accum. Deferred Inc. Taxes - ND ITC	$ 326,744	$ (10,648,260)
Accum. Deferred Inc. Taxes - Fed. portion of ND ITC	$ (114,360)	$ 3,726,891
End of month (September 2018) rate base*	$ 33,503,776	$ 78,601,729

*No proration of ADIT

E2 Factor 37.577%

	September 2018	
RATE BASE (OTP ND)	***Langdon***	***Ashtabula***
Plant Balance - Langdon	$ 29,892,623	$ 43,681,236
Accumulated. Depreciation	$ (12,635,388)	$ (17,274,654)
Net Plant in Service	$ 17,257,235	$ 26,406,582
Inventory	$ 112,654	$ 215,124
Accum. Deferred Inc. Taxes - Fed & State*	$ (6,815,002)	$ (10,576,126)
Accum. Deferred Inc. Taxes - Federal PTC	$ 1,955,132	$ 11,786,401
Accum. Deferred Inc. Taxes - ND ITC	$ 0	$ 6,623,578
Accum. Deferred Inc. Taxes - Fed. portion of ND ITC	$ (0)	$ (2,318,252)
Accum. Deferred Inc. Taxes - ND ITC	$ 122,782	$ (4,001,333)
Accum. Deferred Inc. Taxes - Fed. portion of ND ITC	$ (42,974)	$ 1,400,467
End of month (September 2018) rate base*	$ 12,589,828	$ 29,536,440

*No proration of ADIT

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Bryce Haugen, Senior Rates Analyst, Regulatory Administration

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Data Request:

Please provide the average residential, commercial, industrial and total average retail rate data from EEI "typical Bills and Average Rates Report" for each years of the years 2015-2017 for the following:

- OTP in North Dakota, South Dakota and Minnesota
- West North Central
- National

Attachments: 1

Attachment 1 to DR-MLEC-116.xlsx

Response:

OTP provides Attachment 1 to DR ND-MLEC-116 in response to this request. Because year-end data for 2017 is not yet available, OTP provided July 1 information for all rates in each year. This keeps each year's data as representative as possible year-to-year. All data provided in Attachment 1 to DR ND-MLEC-116 are in cents per kWh.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: North Dakota Public Service Commission
Analyst: Victor Schock
Date Received: 04/11/2018
Date Due: 04/25/2018
Date of Response: 04/24/2018
Responding Witness: Gina Ice, Rate Analyst

Data Request:

For the purpose of this request please refer to the Company's CCOSS study.

a. Please explain how the Company determined the proportion of its production plant that is classified as "base demand" and "peak demand".

b. Please provide all workpapers and source documents in electronic spreadsheet form with all links and formulas intact, source data used, and explain all assumptions and calculations used. To the extent the data requested is not available in the form requested, please provide the information in the form that most closely matches what has been requested.

Attachments: 1

Attachment 1 to DR ND-PSC-12.07.xlsx

Response:

a. Schedule 02 of Gina Ice's Direct Testimony, the Cost Allocations Procedures Manual, shows the calculation used to derive the base demand and peak demand split. It is as follows:

The demand category was then reclassified into Base (Energy-Related) and Peak Demand categories based on the following formulas:

$$\text{Total Current Cost} = (\text{Existing Peaking Capacity [kW]})(\text{Current Peaking Unit Cost [\$/kW]}) + (\text{Existing Steam \& Hydro Capacity [kW]})(\text{Current Base Load Unit Cost [\$/kW]})$$

$$\text{Peaking Demand Factor} = \frac{(\text{Total Existing Plant Capacity})(\text{Current Peaking Unit Cost})}{\text{Total Current Cost}}$$

$$\text{Base (Energy-Related) Demand Factor} = 1 - \text{Peaking Demand Factor}$$

b. Please see Attachment 1 to DR ND-PSC-12.07 for the calculation used to calculate the base and peak demand percentages used in the Test Year.

Case No. PU-17-398
Attachment 1 to DR ND-PSC-12.07
Page 1 of 1

Otter Tail Power Company
Base and Peak Demand Split Data
2018 Test Year

Line No.	(A)	(B)	(C)	(D)	(E)	(F)
		Plant Capacity - KW			Estimated Cost of New Capacity	
1		Steam/Hydro	Other	Total	Base Load	Peaking
2						
3	2016 Actual	548,200	108,100	656,300	$3,804	$599
4						
5	2017 Forecast	548,200	108,100	656,300	$3,918	$617
6						
7	2018 Forecast	548,200	108,100	656,300	$4,036	$635
8						
9						
10	**Calculation of Base Demand and Peaking Demand Factors**					
11						
12	Total Current Cost (TCC) = (A X D) + (B X E)					
13						
14	Peaking Demand Factor (PDF) = (C X E) / TCC					
15						
16	Base Demand Factor (BDF) = 1 - PDF					
17						
18	2016 Actual					
19		TCC =	$2,150,104,700			
20		PDF =	18.28%			
21		BDF =	81.72%			
22	2017 Forecast					
23		TCC =	$2,214,545,300			
24		PDF =	18.29%			
25		BDF =	81.71%			
26	2018 Forecast					
27		TCC =	$2,281,178,700			
28		PDF =	18.27%			
29		BDF =	81.73%			

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/05/2018
Responding Witness: Gina Ice, Rate Analyst

Data Request:

Please answer the following questions with regard to OTP's three-phase and single- phase primary distribution circuits:

a. Please provide the portion of the cost of OTP's primary distribution system that is associated with three-phase circuits. Please also provide the portion that is associated with single-phase circuits? Please provide the information in terms of both percentage of overall primary distribution system and, if available, as a percentage of net plant cost for the primary distribution system.
b. Are single-phase circuits used to provide service to primary voltage customers? If so, how many primary voltage customers does OTP serve and how many primary voltage customers receive their electric service via single-phase primary circuits?
c. What portion of the primary voltage customers' class load is served by single phase circuits?
d. Please confirm that single-phase circuits primarily are used to provide service to secondary voltage customers.

Attachments: 0

Response:

a. OTP does not have the system data available to determine the embedded amount of primary distribution system costs that is associated with single phase and three-phase circuits. Please see the table below for OTP's Total and North Dakota share of primary distribution system costs.

	Net Plant	
	OTP-Total	**OTP-ND**
Primary Demand	$109,513,754	$50,143,286
Primary Customer	$36,005,832	$16,070,101
Total Primary Distribution System	$145,519,587	$66,213,387

b. Single phase circuits are used to provide service to primary voltage customers. OTP serves 49 Primary Service customers throughout its service territories of which 6 customers use single phase circuits.

c. Approximately 0.27% of primary voltage customer load is served by single phase circuits.

d. Yes, single phase circuits are used primarily to provide service to secondary voltage customers.

OTTER TAIL POWER COMPANY
Case No: PU-17-398

Response to: Midwest Large Energy Consumer
Analyst: Richard Savelkoul
Date Received: 02/16/2018
Date Due: 03/05/2018
Date of Response: 03/23/2018
Responding Witness: David G. Prazak, Supervisor, Pricing & Tariff Administration - (218) 739-8595

Data Request:

Regarding the intraclass allocation to the LGS class, please provide the calculations of utilizing EPMC method in excel spreadsheet format and also provide a narrative explanation.

Attachments: 4

Attachment 1 to DR ND-MLEC-120.xlsx
Attachment 2 to DR ND-MLEC-120.pdf
Attachment 3 to DR ND-MLEC-120.pdf
Attachment 4 to DR ND-MLEC-120.pdf

Response:

The EPMC methodology allocates the class revenue responsibilities to rate classes based on each rate class's marginal cost revenues. Marginal cost revenues for a rate class are determined by multiplying the marginal cost (modified as discussed above) times the rate class billing determinants. The background supporting the calculation methodology can be found in Mr. Prazak's Direct Testimony, pages 8 through 10.

The calculations, utilizing EPMC method in excel spreadsheet format, are provided in Attachment 1 to ND-MLEC-120. This attachment reflects a correction to an error in Mr. Prazak's original EPMC allocation within the LGS class, which also impacts the rate design levels for all rates in the LGS class. No change occurred for the proposed LGS Class base rate revenues (excluding riders).

There are five basic steps to develop the proposed change for the LGS Class and its associated rates, as shown in Attachment 1 to ND-MLEC-120, and described below:

Line 1: Change in Non-Fuel Base Revenues. Prazak Direct, Schedule 4, Change in Non-Fuel Base Revenues for LGS Class.

Step 1: Lines 3-8: A table containing 2018 Present Base Rate Revenue (with base fuel but excluding Riders). Prazak Direct, Schedule 4.

Step 2: Lines 9-14: A table containing 2018 Proposed Base Rate Revenue (excluding base fuel and Riders). Prazak Direct, Schedule 4.

Step 3: Lines 15-20: A table containing marginal revenues for the LGS Class. Column G describes the rate efficiency level of the individual rate classes.

Step 4: Lines 21-27: Presents a table of pure EPMC allocation for LGS Class (see Prazak Direct, pp. 8-10)

Step 5: Line 28-34: Presents results of the proposed change for the LGS Class using Method 2a.

EPMC Method 2a was added to correct the error in our original proposed rate design. This new method follows the same concept as Method 2 but makes special adjustments to a couple of rate classes. Method 1 is used for the top two efficient rates - Standby & LGS Primary. LGS TOD is a special case because it contains only one customer in its class. The rate design for the LGS TOD class was designed to be revenue neutral to the LGS NON-TOD Primary and Secondary rate classes. The final revenue requirement for LGS TOD was developed by the revenue it would produce under the revenue-neutral rates. And finally, the LGS Secondary rate revenue allocation was the remainder to achieve the total revenue requirement.

Finally, OTP is providing the following Attachments reflecting the correction discussed above:

- Attachment 2 to DR ND-MLEC-120 – Revised Exhibit___(DGP-1), Schedule 3[1]
- Attachment 3 to DR ND-MLEC-120 – Revised Exhibit___(DGP-1), Schedule 4[2]
- Attachment 4 to DR ND-MLEC-120 – Revised LGS Class Rate Elements.

Attachments 1-4 are prepared based on the present and proposed revenue levels from our Initial Filing. The correction to the LGS rate design shown above and in Attachments 1-4 will be carried through to the final intra-class revenue allocation and rate elements.

[1] Reflects correction to proposed Residential customer charges discussed in ND-PSC-01.21.
[2] Reflects correction to proposed Residential customer charges discussed in ND-PSC-01.21.

ND LGS RATES

LINE No	(A)	(B)	(C)	(D)	(E)	(F)	(G)
1	**% Change in Non-Fuel Base Revenues w/Riders**	**-17%**					
2							
3	**2018 Present Base Rate Revenue WITH BASE FUEL**		Standby Rate	$ 13,134	0.04%		
4			RTP Rider	*$ 1,245,401*	n/a		
5	Step 1		LGS Secondary	$ 27,517,756	76.13%		
6			LGS Primary	$ 8,579,214	23.74%		
7		**LGS Rever**	LGS TOD	$ 34,024	0.09%		
8				**$ 37,389,529**	$36,144,128		
9	**2018 Proposed Base Rate Revenue WITHOUT BASE FUEL**		Standby Rate	$ 10,824			
10			RTP Rider	*$ 1,245,401*			
11	Step 2		LGS Secondary	$ 22,677,157			
12			LGS Primary	$ 7,070,060			
13			LGS TOD	$ 28,039	**LGS Revenues w/o RTP**		
14				**$ 31,031,481**	$29,786,080		**Efficiency Description**
15	**MARGINAL REVENUES**		Standby Rate	$ 11,526	0.03%	94%	Most Efficient 1
16			RTP Rider		n/a		
17	Step 3		LGS Secondary	$ 27,358,886	77.31%	83%	Less Efficient 3
18			LGS Primary	$ 7,983,245	22.56%	89%	More Efficient 2
19			LGS TOD	$ 36,495	0.10%	77%	Least Efficient 4
20				**$ 35,390,152**			
21					**PURE EPMC**		
22	**Pure EPMC Allocation Method**		Standby Rate	$ 9,701	-26%		
23			RTP Rider	*$ 1,245,401*	0%		
24	Step 4		LGS Secondary	$ 23,026,574	-16%		
25			LGS Primary	$ 6,719,089	-22%		
26			LGS TOD	$ 30,716	-10%		
27				**$ 31,031,481**			
28							
29	**EPMC Allocation Method 2a**		Standby Rate	$ 10,301	-22%		
30			RTP Rider	*$ 1,245,401*	0%		
31	Step 5		LGS Secondary	$ 22,824,720	-17%		
32			LGS Primary	$ 6,919,708	-19%		
33			LGS TOD	$31,351.00	-8%		
34				**$ 31,031,481**			

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		
10.04 Large General Service - Secondary Service (Rate 603)												
Customer Charge	Bills			3,272	$40.00	$40.00	$215.90	$215.90	$ 130,873	$ 706,387	$ 575,514	
Energy - First 700,000 kWh (changing to All kWh)	kWh	96,654,016	##########	287,115,510	$0.05115	$0.05165	$0.02905	$0.0298	$ 14,781,189	$ 12,510,482	$ (8,754,125.93)	
Energy - Excess kWh	kWh	49,275,147	87,533,453	136,808,600	$0.04715	$0.04761			$ 6,490,791	$ -		
Demand per kW	kW	322,537	623,784	946,321	$7.29	$5.61	$11.30	$8.50	$ 5,850,722	$ 8,949,038	$ 2,990,067	
Facilities Charge <1,000 kW	kW	212,293	414,007	626,300	$0.30	$0.30	$0.76	$0.76	$ 187,890	$ 473,465	$ 285,575	
Facilities Charge >=1,000 kW	kW	165,998	340,526	506,524	$0.15	$0.15	$0.56	$0.56	$ 75,979	$ 285,330	$ 209,351	
TailWinds Program 14.09	kWh			240	$1.30	$1.30	$3.73	$3.73	$ 312	$ 896	$ 584	
Total Base Revenue:									$ 27,517,756	$ 22,925,598	$ (4,693,036)	
Adjustments for Riders included in Base Rates					***Present***	***Proposed***						
Economic Development Adjustment	kWh			423,924,110	-$0.00022	$0.00000			$ (92,456)	$ -	$ 92,456	
Environmental Cost Recovery Rider Adjustment	%			27,517,756	6.49%	0.00%			$ 1,786,385	$ -	$ (1,786,385)	
Renewable Resource Adjustment	kWh			423,924,110	$0.00510	$0.00000			$ 2,163,720	$ -	$ (2,163,720)	
Transmission Rider Adjustment	kWh			423,924,110	$0.00407	$0.00143			$ 1,725,640	$ 607,573	$ (1,118,067)	
COE Adjustment	kWh			423,924,110	-$0.00340	$0.02463			$ (1,443,142)	$ 10,439,450	$ 11,882,593	
Total Adjustments:									$ 4,140,146	$ 11,047,023	$ 6,906,877	7.3%
10.04 Large General Service - Primary Service (Rate 602)												
Customer Charge	Bills			113	$40.00	$40.00	$282.00	$282.00	$ 4,538	$ 31,993	$ 27,455	
Energy - First 700,000 kWh (changing to All kWh)	kWh	11,345,397	21,942,716	33,288,113	$0.05095	$0.05141	$0.02845	$0.02915	$ 1,706,123	$ 4,104,412	$ (2,678,678)	
Energy - Excess kWh	kWh	36,328,042	72,321,568	108,649,610	$0.04695	$0.04737			$ 5,131,474			
Demand per kW	kW	97,630	184,354	281,984	$7.24	$5.57	$10.90	$8.10	$ 1,733,693	$ 2,558,086	$ 870,702	
Facilities Charge - All kW	kW	85,885	171,505	257,390	$0.11	$0.11	$0.48	$0.48	$ 3,386	$ 124,401	$ 121,015	
Total Base Revenue:									$ 8,579,214	$ 6,818,892	$ (1,659,505)	
Adjustments for Riders included in Base Rates					***Present***	***Proposed***						
Economic Development Adjustment	kWh			141,937,723	-$0.00022	$0.00000			$ (30,956)	$ -	$ 30,956	
Environmental Cost Recovery Rider Adjustment	%			8,579,214	6.49%	0.00%			$ 556,941	$ -	$ (556,941)	
Renewable Resource Adjustment	kWh			141,937,723	$0.00510	$0.00000			$ 724,454	$ -	$ (724,454)	
Transmission Rider Adjustment	kWh			141,937,723	$0.00407	$0.00143			$ 577,777	$ 203,427	$ (374,350)	
COE Adjustment	kWh			141,937,723	-$0.00340	$0.02463			$ (483,191)	$ 3,495,323	$ 3,978,514	
Total Adjustments:									$ 1,345,025	$ 3,698,750	$ 2,353,725	6.0%