BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

Cascade Natural Gas Corporation

Direct Testimony of Nicole A. Kivisto

EXHIBIT 100

May 31, 2018

EXHIBIT 100 – DIRECT TESTIMONY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Nicole A. Kivisto. My business address is 400 North Fourth Street, Bismarck, North Dakota 58501. My e-mail address is nicole.kivisto@mdu.com.

Q. By whom are you employed and in what capacity?

A. I am the President and Chief Executive Officer (CEO) of Cascade Natural Gas Corporation (Cascade or Company) and Intermountain Gas Company, subsidiaries of MDU Resources Group, Inc. (MDU Resources). I am also the President and CEO of Montana-Dakota Utilities Co. (Montana-Dakota) and Great Plains Natural Gas Co., Divisions of MDU Resources.

Q. Please describe your duties and responsibilities with Cascade.

A. I have executive responsibility for the development, coordination, and implementation of strategies and policies relative to operations of the above-mentioned companies that, in combination, serve over one million customers in eight states.

Q. Would you briefly describe your educational and professional background?

A. Yes. I hold a Bachelor's Degree in accounting from Minnesota State University Moorhead. I have worked for MDU Resources/Montana-Dakota since July 1995 and have been in my current capacity since January 2015. I was Vice President-Operations of Montana-Dakota and Great Plains Natural Gas Co., divisions of MDU Resources, from January 2014 until assuming my present position.

Prior to that, I was the Vice President, Controller and Chief Accounting Officer for MDU Resources for nearly four years, and held other finance-related positions prior to that.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this docket?

A. The purpose of my testimony is to provide a high-level overview of the Company's filing and introduce the Company's witnesses.

Q. Please summarize your testimony.

A. In my testimony:

- I will provide an overview of Cascade.
- I will also summarize the Company's rate request in this filing, the primary drivers of the need for rate relief, and provide some background on increasing costs facing the Company.
- My testimony will also describe measures the Company has taken to control costs and increase operating efficiencies.
- I will briefly introduce Cascade's proposed pipeline Safety Cost Recovery Mechanism (SCRM).
- Finally, I will also introduce the other witnesses providing testimony on the Company's behalf.

III. OVERVIEW OF CASCADE

Q. Please briefly provide an overview of the Company.

A. Cascade provides natural gas distribution services in 96 communities in Washington and Oregon. Cascade serves 25 communities in Oregon, the largest of those communities are Bend, Baker City, and Pendleton. Cascade's headquarters are located in Kennewick, Washington. Cascade is wholly owned by MDU Resources, located in Bismarck, North Dakota. Cascade has 288,000 customers, of which 74,000 are in Oregon.

Cascade was originally formed in 1953 to serve smaller communities in the Pacific Northwest. Cascade serves a non-contiguous service territory with 345 dedicated employees. Cascade became a subsidiary of MDU Resources in 2007.

IV. REASONS FOR RATE INCREASE REQUEST

Q. Would you please summarize Cascade's requested increase in this filing?

A. Yes. The rate increase request is largely driven by increased investment in the safety of our system, and offset partially by the decrease in federal income taxes resulting from the Tax Cut and Jobs Act (TCJA). Cascade is requesting an increase of $2,310,808 or 3.53%. This increase is based on an overall rate of return of 7.33%, with a capital structure common equity component of 50%, and a return on equity of 9.40%. The Company is using a partially forecasted test period of the calendar year 2018. The forecasted test period was selected as the most appropriate and supportable for the period during which rates will be in effect. Maryalice Peters provides further discussion regarding the test period in her testimony. The Company is using the results of a long-run incremental cost study as a starting point in the proposed spread of the requested increase to the various rate schedules. Cascade's consultant, Ronald Amen, provides testimony supporting the cost study and rate spread issues.

Q. Has the Company calculated the impact of Cascade's rate request on customers?

A. Yes. Based on an average usage level of 57 therms per month, the average residential customer will see a bill increase of $2.38 per month from, $48.19 to $50.57. This equates to an average increase on a residential customer bill of 4.94%.

Q. What is the primary factor causing Cascade's request for a rate increase in this filing?

A. The primary factor is pipeline replacement costs. In 2011, as required by the Department of Transportation, Cascade prepared a process for evaluating the physical condition of its distribution pipeline. Through the implementation of the evaluation process, Cascade identified a number of areas of concern that could eventually impact the Company's ability to provide safe and reliable service to its customers. As a result, Cascade has devoted a tremendous amount of capital to pipeline replacement and improvement projects over the last six years, and will continue to do so over at least the next five years to ensure the integrity of its system. As an example, Cascade acquired its Bend area in the 1950s. Although Bend has had substantial growth over the years, the pipeline system in the core of the city is older pipe that was placed into service prior to Cascade's acquisition of this system. Cascade is currently entering year seven of a multi-year plan to completely replace the original system. Cascade is also preparing to move into similar replacement projects in Pendleton starting in 2018.

Q. Are there other capital additions planned for 2018 and beyond that will also apply pressure on rates?

A. Yes. Cascade is starting a multi-year encoder receiver transmitter (ERT) replacement project, which is a system-wide project starting with Bend, Oregon.

Q. What is an ERT and what does it do?

A. An ERT is an electronic recording device attached to the meter that sends electronically the metered value which is then used to determine monthly usage for billing purposes.

Q. Is Cascade proposing to replace its meters?

A. No. The existing meters are still usable, however the battery life on the existing ERTs has reached the end of its expected life. The new ERTs will simply replace the existing ERT.

Q. Why is Cascade proposing the ERT replacement project?

A. The Company's ERTs have been in place since 2003/04 and are approaching the end of their useful lives and need to be replaced.

Q. How long will the ERT replacement project take to complete?

A. Cascade anticipates it will take two years to complete the replacement of ERTs. After the ERTs are in place, Cascade will continue to evaluate potential installation of fixed network infrastructure to provide the Company with the capability to electronically gather meter readings even more efficiently than the drive-by method used currently.

Q. How much of the current requested increase of $2.3 million is due to 2018 capital investments?

A. $3.1 million. This means that increased rate base accounts for more than the total request due to the amount which is offset by reductions in tax expense due to the TCJA.

Q. Please identify other drivers of the proposed increase.

A. The other major cost drivers are wage increases and the additional positions being added in 2018. These costs combine for $500,000 of the proposed increase.

Q. Has the Company addressed the TCJA in its request?

A. Yes. As shown in Ms. Peters' Exhibit CNGC/304, Cascade is reflecting a $1.5 million reduction to revenue requirement as a result of the TCJA. Cascade is also reflecting the new 21 percent tax rate in each of its proposed adjustments as well as the proposed conversion factor. Mr. Parvinen provides additional testimony on the impacts of the TCJA.

Q. How has Cascade controlled costs in order to mitigate the need for rate cases?

A. Cascade has a history of mitigating increased cost pressures in order to avoid filing rate cases. In particular, Cascade has a robust budgeting process in place which scrutinizes and prioritizes not only capital projects, but also operating and maintenance expenditures as well. The budgeting process starts with managers and directors compiling a budget based on parameters provided by the executive group. These budgets then are reviewed at the officer level and prioritized based on safety and reliability above everything else. Typically, budgets are then reduced to control costs to an acceptable level. There are a number of rounds of review prior to taking a recommended budget to the board of directors for approval. As a result, Cascade has been able to aggressively manage its costs. The Company's cost-management approach is reflected in the adjustments included in Exhibit CNGC/304, where the primary increases are safety investment and employee costs.

V. CUSTOMER SUPPORT PROGRAMS

Q. Can you describe the customer support programs that Cascade provides for its customers in Oregon?

A. Cascade provides a number of programs to assist customers in meeting their energy bill obligations as well as conservation programs. Cascade has its Low-Income Rate Assistance Program (LIRAP) and its Winter Help program to provide bill assistance to low-income customers. Cascade also offers a budget payment plan to customers, which serves to levelize volatility in bill amounts associated with usage.

Cascade also provides conservation programs through the Energy Trust of Oregon, and through community action agencies specifically serving low-income customers.

In docket ADV 157, Cascade filed for and received approval for its request to make its Conservation Achievement Tariff (CAT) pilot program a permanent program. The CAT supplements the long-standing low-income conservation program by providing full funding of conservation measures thus allowing for substantially more low-income homes to be weatherized. In fact, this program has been so successful the Company has, working in conjunction with Commission Staff, had to apply upper bounds on the program to keep costs more in line with mandated spending limits on low-income weatherization for electric utilities.

Q. Please briefly describe the Budget Payment Plan.

A. The Budget Payment Plan is an option for customers to make a flat payment for a period of time, thus flattening or levelizing their bill. The plan makes it easier for customers to budget their payments. Under the plan, winter bills will be lower than if billed based on actual usage, and summer bills will be higher than if billed based on actual usage. Once a year, the account will be reset based on the previous year's usage and residual balance.

Q. Please describe the level of customer participation in the Company's Budget Payment Plan.

A. As of December 31, 2017, 5,502 or 7.83% of Oregon customers participate in the Budget Payment Plan.

VI. PIPELINE SAFETY COST RECOVERY MECHANISM

Q. Can you briefly describe the Company's proposed pipeline Safety Cost Recovery Mechanism (SCRM)?

A. Yes. The proposed SCRM encourages the Company to invest in replacing its highest risk pipelines by providing timely recovery of such safety investments. As the safety and integrity of Cascade's system is the Company's highest priority, the expedited recovery of the investment is a substantial benefit.

Q. Would the Company continue to make the investments absent the SCRM?

A. Yes. The Company is focused on replacing its highest risk pipeline, and would continue to do so even if the Commission does not approve the SCRM. However, the Commission implicitly recognized in its approval of the stipulation in Docket UM 1722 that it would be beneficial to provide a mechanism for utilities to recover costs for safety related investments in between rate cases. Approval of the SCRM will allow the Company to pursue systematic replacement of its aging pipeline system without needing to file a rate case every year, and customers will benefit by having a safer and more reliable system. The proposed SCRM may also benefit customers, other parties, and Cascade, by potentially reducing the need to file perpetual rate cases while the Company continues to pursue its safety-related pipeline replacement.

Q. If an SCRM were in place, how much of the proposed plant additions included in this case would be included in the SCRM?

A. If an SCRM were in place, $11.1 million of the total proposed $24.55 million would be included in the SCRM—or nearly half of the proposed 2018 plant additions.

VII. OTHER COMPANY WITNESSES

Q. Would you please introduce and provide a brief description of each of the witnesses filing testimony on behalf of Cascade in this proceeding?

A. Yes. The following additional witnesses are presenting direct testimony on behalf of Cascade.

Mr. Michael Parvinen, Director – Regulatory Affairs, will discuss the Company's capital structure, the proposed cost of embedded debt, and the overall rate of return. He will also address the recovery of deferred costs associated with a system-wide records review and process change to bring Cascade's records into compliance with proposed PHMSA rules based on Traceable, Verifiable, and Complete standards. He will also present Cascade's proposed Pipeline Safety Cost Recovery Mechanism (SCRM) and how the mechanism meets the criteria identified in Docket UM 1722. He addresses the Company's position regarding employee incentives and the impacts of the TCJA in the case. Mr. Parvinen will also address Cascade's proposal regarding deferred tax benefits associated with the TCJA during the interim period before rates from this case go into effect.

Ms. Maryalice Peters, Regulatory Analyst, will discuss the Revenue Requirements model and each of the associated exhibits and each of Cascade's proposed adjustments to derive the test year revenue requirement.

Mr. Isaac Myhrum, Regulatory Analyst, discusses the base year revenue proof and the 2018 proposed revenue adjustment.

Ms. Pamela Archer, Supervisor-Regulatory Analysis, discusses the Miscellaneous Revenue Adjustment and the Company's proposal to replace its current tariff, P.U.C. Or. No. 10, with a revised and updated tariff, P.U.C. OR. No. 11.

Mr. Ronald J. Amen, Director – Management Consulting at Black & Veatch, has been retained to prepare and present the Company's long-run incremental cost study for the Oregon service territory. Mr. Amen discusses his study results and how each rate schedule's present and proposed rate compares to the indicated costs.

Q. Does this conclude your pre-filed direct testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

Cascade Natural Gas Corporation

Direct Testimony of Michael P. Parvinen

EXHIBIT 200

May 31, 2018

EXHIBIT 200 – DIRECT TESTIMONY

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I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael P. Parvinen. My business address is 8113 W. Grandridge Blvd., Kennewick, Washington 99336-7166. My e-mail address is michael.parvinen@cngc.com.

Q. By whom are you employed and in what capacity?

A. I am employed by Cascade Natural Gas Corporation (Cascade or Company) as the Director of Regulatory Affairs. In this capacity, I am responsible for the management of all economic regulatory functions at the Company.

Q. How long have you been employed by Cascade?

A. I have been employed by Cascade since September 2011. Prior to joining Cascade I was employed by the Washington Utilities and Transportation Commission (WUTC) for nearly 25 years. At the WUTC, I was employed as a Regulatory Analyst, later as a Deputy Assistant Director, and lastly as the Assistant Director of the Energy Section.

Q. What are your educational and professional qualifications?

A. I graduated from Montana College of Mineral Science and Technology in May of 1986, with a Bachelor of Science degree in Business Administration with an emphasis in accounting.

I have testified before the Public Utility Commission of Oregon (Commission) on behalf of Cascade in dockets UG 224, UM 1633, UG 287, and UG 305. I have also testified numerous times before the WUTC.

I have also analyzed or assisted in the analyses of numerous other utility rate filings, and participated in many utility rulemaking proceedings before the WUTC. Finally, I attended the Seventh Annual Western Utility Rate Seminar in 1987 and the

1988 Annual Regulatory Studies Program, sponsored by the National Association of Regulatory Utility Commissioners.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. Please describe the purpose of your testimony in this docket, and summarize your testimony.

A. The purpose of my testimony is to provide an overview of the Company's proposed capital structure and major new proposals in this case. My testimony includes the following components:

- First, I explain and support the capital structure and rate of return requested in this proceeding;
- Second, I discuss the Company's proposal for the amortization of costs deferred under Docket UM 1816;
- Third, I provide an update to the recovery tariff associated with costs deferred in connection with the Company's environmental remediation costs;
- Fourth, I discuss the impact of the Tax Change and Jobs Act (TCJA) and the Company's proposal for the deferred amounts from January 1, 2018, until the effective date of this rate case; and
- Fifth, I present the Company's proposed Safety Cost Recovery Mechanism (SCRM); and
- Sixth, I present an overview of the Company's approach regarding employee compensation and incentive pay.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits, which are described in my testimony:

- Exhibit CNGC/201 Cascade's Actual Capital Structure, 2012-2017

- Exhibit CNGC/202 Calculation of Rate for Schedule 197, Environmental Remediation Cost Adjustment
- Exhibit CNGC/203 Impacts of the Tax Cuts and Jobs Act
- Exhibit CNGC/204 SCRM Example Calculation

III. CAPITAL STRUCTURE AND RATE OF RETURN

Q. What is the rate of return and capital structure that Cascade is requesting in this case?

A. The Company is requesting a rate of return of 7.33% with a capital structure of 50% equity and 50% debt. The components and calculation of the proposed rate of return are shown in Table 1.

Table 1. Proposed Rate of Return

	Capital Structure	Cost	Component
Common Equity	50%	9.40%	4.700%
Total Debt	50%	5.25%	2.625%
	100%		7.325%

Q. Why does the Company believe a capital structure of 50% equity and 50% debt is appropriate?

A. The requested capital structure is based upon Cascade's actual capital structure over the last six years. The Company is committed to maintaining a healthy capital ratio which, we believe, is in the best interests of both our shareholders and customers. In fact, as of April 30, 2018, Cascade's actual capital structure was at 52% equity. Cascade believes a 50/50 capital structure is supported and reasonable.

Q. Do you have an exhibit summarizing the Company's actual capital structure over the past six years?

A. Yes. Exhibit CNGC/201.

Q. Why is the Company proposing a 9.40% return on equity (ROE)?

A. The Company believes a 9.40% ROE is a reasonable and adequate, and is consistent with the Commission's recent determination for ROE for a natural gas utility.[1]

IV. AMORTIZATION OF DEFERRED COSTS UNDER DOCKET UM 1816

Q. Please describe the deferral request filed under Docket UM 1816.

A. On January 6, 2017, Cascade filed for authority to defer certain one-time costs paid to an outside third-party vendor, TRC Pipeline Services, LLC to perform a records review of Cascade's high-pressure distribution and transmission pipelines.

Q. Has the Commission approved Cascade's request for deferral?

A. No, the Commission has not yet approved the Company's request for deferral. Cascade recommends that the Commission consider and approve the request for deferral as well as the Company's proposed amortization in this rate case.

Q. Did the Company defer the costs described in its deferral application in Docket UM 1816?

A. Yes. The Company booked the costs described in its deferral application as a regulatory asset. The Company has since closed its 2017 books.

[1] *See In the Matter of Avista Corp., dba Avista Utils., Request for a Gen. Rate Revision,* Docket No. UG 325, Order No. 17-344 (Sept. 13, 2017).

Q. What was the purpose of the records review?

A. The Company performed the records review for its Washington system as part of a settlement agreement regarding validation of its records regarding maximum allowable operating pressure (MAOP) for its high-pressure distribution and transmission pipelines. The Company decided that it would be prudent to perform a similar review in Oregon, which would have the added benefit of providing a baseline for evaluating Cascade's records for compliance with existing MAOP guidelines and the proposed standards of the U.S. Department of Pipeline and Hazardous Materials Safety Administration (PHMSA) that pipelines records must be "traceable, verifiable, and complete."

Q. What does "traceable, verifiable, and complete" mean?

A. Documentation meeting the "traceable, verifiable, and complete" standard must be:

- **Traceable.** Traceable records are those which can be clearly linked to original information about a pipeline segment or facility. Traceable records might include pipe mill records, purchase requisition, or as-built documentation indicating minimum pipe yield strength, seam type, wall thickness and diameter.
- **Verifiable.** Verifiable records are those in which information is confirmed by other complementary, but separate, documentation. Verifiable records might include contract specifications for a pressure test of a line segment complemented by pressure charts or field logs.
- **Complete.** Complete records are those in which the record is finalized as evidenced by a signature, date or other appropriate marking. For example, a complete pressure testing record should identify a specific segment of pipe, who conducted the test, the duration of the test, the test medium, temperatures, accurate pressure readings, and elevation information as applicable.[2]

Q. Why is it important that records be "traceable, verifiable, and complete"?

A. Pipeline records are an essential component of managing pipeline safety. When explaining the need for the "traceable, verifiable, and complete" standard, PHMSA has indicated that "inspections and investigations indicate that efforts to collect and

[2] *See* PHMSA ADB-2012-06, Fed. Reg. Vol. 77, No. 88 at 26,823-26,824 (May 7, 2012).

integrate risk information can be inappropriately narrow, lack verification and fail to take into account relevant risk information and lessons learned from other parts of their system."[3] The proposed PHMSA standards are a complete system requirement to assure a safe pipeline system and Cascade's commitment to meet these standards reflects Cascade's commitment to safety.

Q. Would the proposed PHMSA standard apply to both new and older pipeline segments?

A. Yes. The PHMSA standard would be applied to all vintage years, so Cascade's proactive approach places Cascade's pipeline system well in front of the curve to ensure that Cascade is providing a truly safe and reliable system. The current MAOP requirements include grandfathering older systems as well as less stringent requirements on newer vintages.

Q. Has PHMSA adopted the proposed "traceable, verifiable, and complete" standard?

A. No. While the "traceable, verifiable, and complete" standard has not yet been adopted, Cascade anticipates that this standard may be adopted in 2019.

Q. Why did the Company have the evaluation performed now, before the PHMSA rules are in place?

A. As described above, we were performing similar work for other parts of our Washington pipeline system, and believed it would be beneficial to verify and modernize our Oregon records, as well. Additionally, we believe that PHMSA's proposed "traceable, verifiable, complete" standard will be adopted soon. By performing this detailed records review Cascade has taken steps placing it well

[3] Establishing Maximum Allowable Operating Pressure Using Record Evidence, 76 Fed. Reg. 1504, 1505 (Jan. 10, 2011).

ahead of other pipeline operators who will ultimately need to take these steps to comply with the proposed PHSMA rules. An additional benefit of performing this detailed records review is that the quality of the Cascade's MAOP validation documentation has been thoroughly vetted and Cascade has greater certainty regarding the integrity of its system.

Q. Are there benefits associated with the records review beyond providing the Company a foundation for meeting the PHMSA standard?

A. Yes. As a result of the records review, Cascade now has a fully searchable electronic database of digital files relating to MAOP information, and these files are linked to the Company's Geographic Information System (GIS) records. Prior to the study, the Company's files for MAOP validation required a manual review of existing records any time an issue came up. And because those records were not centralized, locating records was often cumbersome and time-consuming. The new electronic files will allow for more efficient and accurate retrieval of information, which will benefit customers into the future.

Q. What was the total cost of the review?

A. Cascade originally estimated that it would cost $950,000 to $1,000,000. Ultimately, the project was completed by July 2017, and the total costs deferred were approximately $525,000, well under budget.

Q. What is Cascade's proposal in regard to these costs?

A. Cascade proposes that the Commission approve the Company's request for deferral and proposed five-year amortization of these costs, beginning with the effective date of this filing. The estimated balance at the end of March 2019, which includes the total amount deferred in 2017 with interest, will be $583,621.81.

Q. In accordance with ORS 757.259(5), the Commission must perform an earnings review at the time the Company asks for amortization of a deferral. What were Cascade's earnings in 2017?

A. As shown in the Company's results of operations in Exhibit CNGC/301, the "2017 Results Per Company Filing" column shows that Cascade's actual 2017 earnings were 5.66 percent, which is well below the current authorized return of 7.284 percent. On April 27, 2018, Cascade filed its annual earnings review in Docket RG 36, which also shows a 6.48 percent return, which is again well below the Company's authorized return for 2017. Cascade clearly meets the earnings test required in ORS 757.259(5).

Q. What is the impact of this adjustment as proposed?

A. This adjustment is a decrease to net operating income of $85,204. The adjustment can be found in Exhibit CNGC/304, column (q).

V. ENVIRONMENTAL REMEDIATION COST ADJUSTMENT TARIFF UPDATE

Q. Please provide a brief history of the Eugene Remediation Site and process.

A. A predecessor in interest to Cascade operated a Manufactured Gas Plant (MGP) in Eugene, Oregon. The Eugene Water & Electric Board (EWEB) now owns the property, and Cascade, along with PacifiCorp and EWEB participated with Oregon Department of Environmental Quality (DEQ) oversight to perform initial studies and to determine cleanup project objectives. EWEB, PacifiCorp, and Cascade entered into a participation agreement for site investigation, and are having discussions regarding a cost sharing agreement under which Cascade is responsible for a portion of all investigation and remedial design costs. In January of 2015 the DEQ issued a Record of Decision (ROD) identifying the measures to remediate the site.[4]

Q. Has Cascade been deferring the expenses associated with environmental remediation that have been incurred to date?

A. Yes. Consistent with Cascade's petition for deferred accounting in Docket UM 1636, and the Commission's orders approving the same, the Company has been deferring expenses associated with environmental remediation work since 2013.[5]

Q. Has the Company begun to amortize any portion of the amounts deferred in Docket UM 1636?

A. In Cascade's last general rate case, Docket UG 305, the settlement provided for a three-year amortization of the deferred balance that had accrued to date. The intent was to start recovery rather than wait until some future date when costs (and related interest on the deferral account) could be substantially greater. The Company implemented the settlement through its Environmental Remediation Cost Adjustment, Schedule 197.

Q. Please describe the Environmental Remediation Cost Adjustment.

A. The Environmental Remediation Cost Adjustment is a rider that charges customers on Schedules 101 (Residential), 104 (Commercial), 105 (Industrial), 111 (Large Volume General Service), 163 (General Distribution System Interruptible Transportation Service), 170 (Interruptible Service), and 800 (Biomethane Receipt Service) in the amount of $0.000514 per therm.

[4] Cascade included a copy of the ROD as Exhibit CNG/309 in its 2015 rate case filing, Docket UG 287.

[5] Cascade filed its initial petition for deferred accounting on November 30, 2012, and thereafter the Company has annually filed for—and the Commission has granted—Cascade's requests for reauthorization of its deferral for environmental remediation expenses. *See, e.g. In the Matter of Cascade Natural Gas Corp., Application for Reauthorization for Deferral of Environmental Remediation*, Docket No. UM 1636, Order No. 17-491 (Dec. 6, 2017) (most recent order approving Cascade's request for reauthorization of deferred accounting for environmental remediation expenses).

Q. Has the Company continued to defer additional environmental remediation expenses since its last rate case?

A. Yes. The Company has continued to defer costs associated with environmental remediation work, specifically for the design phase of the remediation work. The total remediation project consists of primarily three phases; investigation, design, and then remediation. The investigation was complete as of the last rate case, design is now complete, and the actual remediation is expected to begin in 2019. The City of Eugene is contemplating building a roundabout on the MGP site that may impact the final remedy, which is delaying the original remediation schedule start date to 2019.

Q. Has the Company received any insurance proceeds to offset the additional environmental remediation expenses?

A. Yes. In total Cascade has received just over $263,000 of insurance proceeds through May 2018 related to the investigation phase of the project. Work is currently being performed to determine the insurer's responsibilities for the final phase of the actual remediation work. It is currently anticipated that Cascade's portion of the final phase will cost approximately $1.5 million prior to any possible insurance proceeds.

Q. What is the Company proposing in this case?

A. The Company is proposing to combine the remaining unamortized balance authorized in the last general rate case, which is approximately $54,000, with the most current deferred balance, which is approximately $193,000, and amortize the total balance, $247,000, over three years, consistent with the approach that parties agreed to in the last rate case. The Company proposes to update Schedule 197 to reflect a three-year amortization of the total balance for a rate of $.000303 per therm collecting $84,858 per year. These figures and the calculation of the amortization rate are shown in Exhibit CNGC/202.

Q. Does the Company's proposed approach impact the revenue requirement in this case?

A. No. The Environmental Remediation Cost Adjustment is independent of the Company's revenue requirement request.

Q. What is the rate per therm for the proposed update to Schedule 197?

A. As shown in Exhibit CNGC/202, Schedule 197 is proposed to decrease from $.000514 per therm for the existing tracker amount, to $.000303 per therm.

Q. Will there be on-going costs associated with the Eugene Remediation Site?

A. Yes, and Cascade expects to continue to defer additional on-going costs for future recovery.

VI. TAX CUTS AND JOBS ACT (TCJA) IMPACT

Q. Please explain how Cascade is reflecting in this case the new 21 percent federal tax rate contained in the "Tax Cuts and Jobs Act" (TCJA) signed into law on December 22, 2017, and effective January 1, 2018.

A. There are four main components to the TCJA impacts included in this case. First, there is an adjustment to the Company's revenue requirement to reflect the new lower tax rate. Second, there is return of the excess deferred income tax (EDIT). Third, the conversion factor is impacted by the change in the tax rate as well as the impact on each individual adjustment. Finally, there is a description of Cascade's proposal regarding the amounts that are currently being deferred per the petition for deferral of the net benefits associated with the TCJA in Docket UM 1927.

Q. Regarding the first component, did the Company apply the new 21 percent tax rate in calculating its proposed revenue requirement?

A. Yes. Cascade converted the book federal income tax expense from 35 percent to the new tax rate of 21 percent. This calculation is described later in my testimony and is provided in Exhibit CNGC/203.

Q. Regarding the second component, could you please explain what EDIT is and why it is necessary to consider EDIT in this case?

A. EDIT results from the implementation of the new federal tax rate in the TCJA to the underlying booked tax differences that produce the deferred taxes. For example, if there is a booked tax difference that produces a deferred tax liability amount representing a future tax obligation, the obligation was reevaluated to reflect the lower tax rate that will apply in the future.

Q. How will EDIT be reflected in rates?

A. As a result of the new tax rate Cascade was required to book the EDIT as of December 31, 2017, and Cascade is required to return these benefits to customers as customers paid these benefits. The EDIT consists of two components: plant and non-plant. Plant-related EDIT, which consists of protected EDIT and a very small component of non-protected EDIT, is required to be passed back to customers using the Average Rate Assumption Method (ARAM). For the non-plant EDIT Cascade is proposing a ten-year amortization.

The full amount of EDIT is reflected as a rate base reduction through the deferred income taxes, but the reversal of the plant-related EDIT and the amortization of the non-plant EDIT is reflected through the second component of the Company's proposed adjustment. The Company also reflects a corresponding rate base increase for the expense adjustment. This amount is also shown in Exhibit CNGC/203.

Q. What is the third component related to the tax change?

A. The conversion factor and the tax impact of each revenue requirement adjustment are calculated using the 21 percent tax rate. Each proposed adjustment shown in Exhibit CNGC/304 also reflects the 21 percent federal tax rate. The conversion factor calculation is shown in Exhibit CNGC/303. Both Exhibits CNGC/303 and CNGC/304 are sponsored by Company witness Ms. Peters.

Q. Regarding the fourth component, how is Cascade proposing to treat the tax benefits during the period from January 1, 2018 until the effective date of this rate case, March 31, 2019 (Interim Period)?

A. As described in Cascade's deferral application in Docket UM 1927, Cascade has been deferring the benefits for the Interim Period as of January 1, 2018, and will continue to do so until the effective date of this rate case, which is anticipated to be April 1, 2019. The monthly deferral is based on actual operations with the benefits being calculated using a "with and without" tax reform basis applied to actual results. Cascade is further proposing that the deferred balance be included in the annual earnings review and to the extent Cascade is exceeding its authorized return on equity Cascade would propose returning to customers all amounts exceeding the authorized return on equity.

Q. Do you present an exhibit summarizing the impact of the TCJA?

A. Yes. Exhibit CNGC/203 summarizes the first and second components of the impacts of the TCJA as described above in my testimony—the reflection of the tax rate change in rates on a going-forward basis, and the return of the EDIT. The results of Exhibit CNGC/203 are then reflected in the Company's revenue requirement summary exhibit, Exhibit CNGC/304, in the adjustment column labeled "TCJA Impact." This adjustment has two components. First, the adjustment takes the 2017 booked federal income tax and divides by 0.35 and then multiplies by 0.21. This converts the booked tax to 21 percent. The second component then adjusts to reflect the impacts of the reversal and amortization of the EDIT, thus reflecting the benefits paid by customers at 35 percent and the corresponding rate base impact.

VII. PIPELINE SAFETY COST RECOVERY MECHANISM (SCRM)

SCRM Proposal is Consistent with Commission Guidelines

Q. Is the Company proposing a pipeline Safety Cost Recovery Mechanism (SCRM)?

A. Yes. The Company is proposing an SCRM to provide for timely recovery of the Company's safety-related investments without having to file a rate case each time the Company makes such investments.

Q. Has the Commission approved guidelines for this type of mechanism?

A. Yes. In Docket UM 1722, the Commission investigated recovery of safety-related costs by natural gas utilities, and the parties to that docket reached a settlement, which the Commission ultimately approved. The settlement provided for the annual filing of safety plans by local distribution companies (LDC) and allowed for LDCs to request approval for cost recovery for safety-related investments through a pipeline safety cost recovery mechanism.[6] The settlement also established guidelines for approval of a pipeline safety cost recovery mechanism.[7] Per the settlement, the guidelines are:

[6] *In the Matter of Pub. Util. Comm'n of Or. Investigation into Recovery of Gas Safety Costs by Natural Gas Utils.*, Docket No. UM 1722, Order No. 17-084 (Mar. 6, 2017).
[7] *See* Order No. 17-084.

- **Guideline 1.** An SCRM may be established in a general rate case (GRC) or within three years of a final order in a GRC.
- **Guideline 2.** An SCRM will be limited to discrete safety-related capital investments or other costs that are capitalized and that are identifiable at the time the SCRM is established. An LDC may request authorization from the Commission to modify an SCRM to include additional discrete safety related capital investments that otherwise meet these guidelines, and other parties are free to support or oppose such a request.
- **Guideline 3.** An SCRM shall have a cost recovery cap, which will be set at the time the SCRM is established. The cost recovery cap may be adjusted up or down by the Commission to reflect related projects that may be included in the SCRM in later years, or the removal or modification of safety related projects included in the SCRM.
- **Guideline 4.** SCRMs will be subject to an annual earnings test that will allow utility investments to be tracked into rates only where the recovery does not cause the utility to exceed its authorized Return on Equity.
- **Guideline 5.** An SCRM will only recover eligible costs on an annual basis to the extent the LDC's total annual capital investments in all plant exceeds the annual amount of depreciation for the LDC's Oregon rate base.
- **Guideline 6.** The duration of the SCRM will be specified at the time the SCRM is established. The duration may be modified if new safety-related projects are added to the SCRM in later years by the Commission.[8]

Q. Does the Company's proposal meet these guidelines?

[8] Order No. 17-084, App. A at 3-4.

A. Yes. Below is an explanation of how Cascade's proposed mechanism meets the guidelines.

Q. Does the proposal meet the requirement in Guideline 1 that an SCRM must be established in a GRC or within three years of a final order in a GRC?

A. Yes. Cascade is filing its request for an SCRM in the current general rate case.

Q. Does the proposal meet the requirement in Guideline 2 that the SCRM be limited to discrete safety related capital investments or other costs that are capitalized and that are identifiable at the time the SCRM is established?

A. Yes. Cascade proposes to include in the SCRM the four identified projects in the Company's 2018 Annual Oregon System Safety Plan, which was filed by the Company on May 21, 2018 in Docket UM 1899.[9] Those projects include three pipeline replacement projects in the Bend area (two in Bend and one in Madras) and one pipeline replacement in Pendleton. Cascade also proposes to include a bare-steel pipeline replacement project in Milton-Freewater, which is anticipated to begin in 2019.

Q. Are these projects also included in the Company's request for recovery in this case?

A. Cascade is proposing to include the 2018 phase of work on the four projects identified in the Safety Plan (Bend and Pendleton) in this rate case, and proposes that cost recovery for subsequent phases of these projects should be included in the SCRM, beginning in 2019.

[9] *See In the Matter of Cascade Natural Gas Corp. Annual Natural Gas Safety Plan*, Docket No. UM 1899, Safety Plan at 13 (May 21, 2018).

Q. What are Cascade's estimated costs for these projects?

A. Approximately $11.4 million of investment is expected to be completed in 2018, and as described above, this amount is included in the Company's request in this case. Thereafter, the estimated annual budget for the projects proposed to be included in the SCRM totals approximately $10-13 million per year.

Q. Will Cascade propose updates to the SCRM to reflect additional projects meeting the SCRM guidelines in the future?

A. Likely yes. Assuming the Commission approves the SCRM in this case, Cascade may in the future propose that additional projects be included in the SCRM. Cascade anticipates that these projects would be discrete and specifically identified replacement projects based on the highest-risk areas as identified in the Company's DIMP modeling and which are identified in the Company's annual System Safety Plan filing.

Q. Is the Company proposing a cost recovery cap for the SCRM, consistent with Guideline 3?

A. Yes. Cascade proposes that the SCRM should include a cost recovery cap that is limited to a 2.5 percent increase in rates. For reference, the rate impact for the four projects included in the current docket, would result in a 1.99 percent increase in rates if included in a SCRM as proposed by the Company.

Q. Will the proposed SCRM revenues be subject to earnings sharing as required by Guideline 4?

A. Yes. Cascade will include the SCRM revenues in the annual evaluation of its existing earnings sharing mechanism to assure the SCRM does not cause Cascade to overearn.

Q. Does the proposal comply with Guideline 5, providing that eligible costs may be recovered only to the extent that the LDC's total annual capital investments in all plant exceeds the annual amount of depreciation for the LDC's Oregon rate base?

A. Yes. As part of Cascade's annual recovery request, Cascade will demonstrate its total annual investment for all plant additions exceeds its annual depreciation expense.

Q. Guideline 6 requires that a duration be specified for the SCRM at the time it is established. What is Cascade's proposed duration for the SCRM?

A. Cascade proposes that the mechanism be allowed to run as long as its total capital expenditures exceed its annual depreciation expense or until Cascade has significantly reduced its system risk. Cascade estimates the timeline to be approximately fifteen years. To be conservative, however, Cascade proposes that its SCRM be established for five years at which time the Company and parties can revisit the merits of the mechanism.

Q. Does Cascade currently have a similar mechanism in place in Washington?

A. Yes. As a result of a generic proceeding (Docket UG-120715), the WUTC issued a policy statement encouraging natural gas utilities to be proactive in replacing higher risk pipelines. The policy encourages the utilities to submit a replacement plan which is to be updated every two years. The utilities then have the option to file a Cost Recovery Mechanism (CRM) for the investment associated with the plan. The plan uses the DIMP as its primary support.

Q. Will Cascade also file a plan as part of its proposal in this docket?

A. Not specifically. However, Cascade intends to use its Safety Plan as required in UM 1722 to identify specific projects the Company will propose for recovery in the SCRM.

<u>Cascade's Need for an SCRM</u>

Q. Why is Cascade proposing an SCRM?

A. The proposed SCRM is a mechanism intended to provide timely recovery of costs incurred to promote the safety and reliability of Cascade's distribution system. The Company is using its Distribution Integrity Management Plan (DIMP) to identify and replace certain areas of the distribution system that are at elevated risks of failure.

Q. Why is Cascade incurring these types of costs?

A. There are many portions of Cascade's system that include what is deemed as high-risk pipe. Cascade is serious about its obligation to provide safe, reliable service to its customers, and to that end, Cascade is using a systematic approach to identify the highest risk areas and replace those sections of pipe. The Company believes that these systematic pipeline safety investments are prudent and necessary to provide a safe reliable system.

Q. Are these projects revenue producing?

A. No. The projects associated with these investments provide for pipeline replacement, with no new revenue associated with them. In other words, performing these system improvements increases the Company's costs, and because there are no additional revenues associated with these projects, the Company's earnings will be reduced.

Q. Has Cascade been investing in these types of safety projects over the last several years?

A. Yes. Cascade has invested a significant amount over the last six years in replacing its infrastructure. In particular, Cascade has been focusing on the Bend area and systematically replacing its gas pipeline system in that area. Each year of replacement is considered a "Phase," and the work performed in 2018 is also referred to as Phase 7. Cascade has spent a total amount of $13.4 million in Phases 1 through 6. Cascade is also expanding its focus to other areas of its system including Pendleton beginning in 2018. The work proposed to be included in the SCRM includes Phase 8 through 12, for the work that will be completed over the next five years.

Q. How has Cascade been able to incur these costs without rate recovery to date?

A. During the first three phases, Cascade used the synergy savings and efficiency gains from the acquisition of Cascade by MDU Resources to fund these system improvements. However, rate base and other cost increases have reached the point that Cascade has filed rate cases in three of the last four years or phases. These investments have been the primary drivers in seeking this current rate increase request along with the past two rate cases. The proposed SCRM can help alleviate the need for annual rate requests.

<u>SCRM Timing and Process</u>

Q. **Can you please describe how the SCRM is proposed to work?**

A. Yes. Cascade proposes to file for recovery of its annual investment on November 1 with an effective date of February 1. The November 1 filing will request recovery of investment from January 1 through December 31. For January through September the Company will have actual costs, and October through December will be projected. Cascade will file an update January 15 which will then include actual investments through December 31. All investments will therefore be in service at the time of final review.

Q. When will the first filing take place and will it cover a full year?

A. The current general rate case filing is proposing to recover investments through the end of 2018; therefore, the first proposed filing will cover investments made after January 1, 2019, through December 31, 2019. The first filing will be made November 1, 2019.

Q. Have you prepared an exhibit demonstrating how the mechanism would work?

A. Yes, Exhibit CNGC/204.

Q. Please describe Exhibit CNGC/204.

A. Exhibit CNGC/204 provides a sample spreadsheet demonstrating the calculation of annual rate changes as well as a line by line description of the spreadsheet.

Q. How will the SCRM benefit customers?

A. Besides the benefits of allowing timely recovery for Cascade's investments in making its system safer and more reliable, the SCRM will potentially reduce the need for back-to-back rate cases. If the Company is filing rate cases less frequently, the Company will have an additional incentive to control costs between rate cases—creating a downward pressure on costs overall. Fewer rate cases will also save costs and Company resources that would otherwise be spent preparing and litigating additional rate cases.

Q. What is the likely impact if the Commission rejects the Company's proposed SCRM?

A. As explained in the testimony of Cascade's witness Nicole Kivisto, the Company is focused on replacing its highest risk pipeline, and would continue to do so even if the Commission does not approve the SCRM. However, the Commission implicitly recognized in its approval of the stipulation in Docket UM 1722 that it would be beneficial to provide a mechanism for utilities to recover costs for safety related investments in between rate cases. Approval of the SCRM will allow the Company to pursue systematic replacement of its aging pipeline system without needing to file a rate case every year, and customers will benefit by having a safer and more reliable system.

VIII. EMPLOYEE COMPENSATION AND INCENTIVE PAY

Q. Please describe the amounts for employee salaries and benefits included in this case.

A. The Company has included in this case $8.9 million for employee salaries and benefits. This amount includes the Test Year (2018) base salaries and base year (2017) incentive pay, medical benefits, and contributions to retirement funds.

Q. Is the Company including amounts for all incentive pay plans provided by the Company?

A. No. The Company is including 100 percent of all amounts estimated to be paid out under the employee incentive pay plans (excluding executive incentive pay) equal to the amounts provided in the base year.

Q. Why are you including 100% of all amounts estimated to paid out under the employee incentive plans?

A. Payments under employee incentive plans are an integral component of market compensation. And it is essential that we pay our employees compensation at market, in order to attract and retain a qualified workforce. Therefore, it is fair and appropriate that these costs be included in customer rates. We do understand that in the past, the Commission has included only a portion of employee incentive plans in customer rates, based on the view that these plans—at least to some extent—benefit shareholders instead of customers. However, we disagree with this view and believe that the Commission should reconsider its position. If the Commission does not wish to reconsider its past policy in this individual utility ratemaking proceeding, then we would propose that the Commission open a generic proceeding, including all stakeholders to reconsider the issue.

Q. Does this conclude your testimony?

A. Yes it does.

CNGC/201
Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MICHAEL P.
PARVINEN
Exhibit No. 201

Cascade's Actual Capital Structure
2012-2017

Cascade Natural Gas Corp
Year End Capital Structure

	12/31/2012	12/31/2013	12/31/2014	12/31/2015	12/31/2016	12/31/2017	Average	Projected End of 2018
Total Debt	46%	52%	49%	53%	52%	50.8%	50%	49.8%
Common Equity	54%	48%	51%	47%	48%	49.2%	50%	50.2%

CNGC/202
Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MICHAEL P.
PARVINEN
Exhibit No. 202

Calculation of Rate for Schedule 197, Environmental Remediation Cost Adjustment

Cascade Natural Gas Corp
Environmental Remediation Amortization
3 Year Amortization of March 31, 2019 Balances

UG 305 Balance to Amortize	162,000	
Started Amortizing 3/1/2017		
Remaining Balance at March 1, 2019		54,000
Current Deferred Balance from UM 1636		
Balance @ February, 2018 with interest		
through March 31, 2019		192,749
Total to be amortized		$246,749
Three year Amortization		82,250
Grossed up for Revenue Sensitive		84,858

Schedule 197, Environmental Remediation Costs Adjustment Rate

Rate Class	Volumes
101	42,977,440
104	30,286,424
105	2,037,630
111	1,629,956
163	201,091,680
170	2,418,468
Total	280,441,598

Schedule 197 Rate $0.000303

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MICHAEL P.
PARVINEN
Exhibit No. 203

Impacts of the Tax Cuts and Jobs Act

Cascade Natural Gas Corporation
UG 347

TCJA Adjustment
Twelve Months Ended December 31, 2017

Line No.			Booked FIT @ 35%	Adjusted To 21%	Adjustment
1	Account 409.1	Federal Inc Taxes, Util Oper Inc	(726,061)	(435,636)	290,424
2	Account 410.1	Provision For Defer'd Fed Inc Tax	2,219,474	1,331,684	(887,790)
3		Total	1,493,413	896,048	***(597,365)***

Line No.			Total System	2018 Excess ARAM & Amortization	Oregon Percentage (Plant Allocator)
4	EDIT				
5		Plant	41,264,063	1,699,492	382,556
6		Non-Plant	7,894,732	789,473	177,710
					560,266
7		Total FIT Adjustment			**(1,157,631)**
8		Rate Base Impact			560,266

CNGC/204
Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MICHAEL P.
PARVINEN
Exhibit No. 204

SCRM Example Calculation

Description of Template in Page 3

Exhibit CNGC/204, page 3 is a template with no specific projects or dollar significance intended. Lines 1 – 7 in the exhibit represent individual projects included in the mechanism. The number and cost of the projects will vary from year to year. Column (b) shows the estimated cost to be recovered with column (c) identifying actual costs spent from January through the various update points. In the January 15 update filing, both column (b) and (c) will be the same and represent actual costs for the twelve months ended December 31.

Line 8 is the total of all projects. Line 9 comes from the accepted Mains Investment allocation from the current cost of service study in this filing. The mains investment allocator will be used to allocate the plant additions to each customer class. Line 10 shows the percentage split based on the previous line.

Line 11 is a reiteration of line 8, total replacement costs. Lines 12 – 23 calculate the revenue requirement impact of the investment. The calculation takes into account the average depreciation rate for steel mains and polyethylene services approved in Cascade's last depreciation study, line 12. The accumulated depreciation impact is derived on line 13, assuming a half year convention. Line 14 calculates tax depreciation in order to determine the deferred tax component on line 16. Line 17 is the tax effect of depreciation expense. Line 18 is the calculated rate base. Line 19 is the rate of return requested in this rate case. Line 20 shows the Net Income impact of the rate base and income statement with line 21 showing the total. Line 22 is the conversion factor derived in this current rate case filing. Line 23 is the total revenue requirement associated with the first year of the pipeline replacement investment.

Line 24 shows the allocation of the revenue requirement to each of the rate schedules based on the rate base allocation percentage shown on line 10. Line 25 shows the weather normalized volumes expected in the upcoming year. This volume projection will be the same as used in the most current PGA filing plus expected Schedule 163 transportation volumes.

Line 26 will show the proposed rate impact to be included on a newly established tariff schedule.

Each subsequent year will add an additional sheet similar to this template in order to reflect an additional year of depreciation and deferred taxes on the rate base. In subsequent years the first page will look the same as this exhibit except that additional lines will be added to bring forward the previous year's new rate base level. There will be a second page which will look identical to first year with the exception of added accumulated depreciation and added deferred taxes.

Cascade Natural Gas
Pipeline Safety Cost Recovery Mechanism (SCRM) Template Calculation

Replacement Projects 1-1-19 to 12-31-19

	Project (a)		**Estimated 2019 Total Cost (b)**	**30-Sep-19 Actual Cost (c)**					
1	Bend Pipe Replacement Phase 8		$2,590,587	$1,000,000					
2	6" Bend HP Replacement Phase 2		$1,816,828	$0					
3	Prendleton Pipe Replacement Phase 2		$2,100,978	$1,000,000					
4	4" Madras HP Replacement Phase 2		$4,751,256	$500,000					
5	Milton-Freewater Bare Steel Replacement		$1,811,880						
6	x6		$0						
7	x7		$0						
8	Total Estimated Replacement Cost		$13,071,529	$2,500,000					
				Schedule 101	**Schedule 104**	**Schedule 105**	**Schedule 111**	**Schedule 170**	**Schedule 163**
9	Main Investment Allocation from UG 347 Company COS (Exh CNGC/603)		$387,970,329	$193,302,520	$116,451,724	$15,905,278	$4,300,755	$2,612,997	$55,397,055
10	Percentage		100.00%	49.82%	30.02%	4.10%	1.11%	0.67%	14.28%
11	Total Investment	Ln 8	13,071,529						
12	Depreciation Expense - Rate 2.96%	Ln 11* 2.56.5%	335,285	335,285					
13	Accumulated Depr. (Avg)	Ln 12 / 2	167,642						
14	Tax depreciation - Rate 5.00%	Ln 11 *3.75%	490,182						
15	Deferred Tax	(Ln 14 - Ln 12) * .27004	41,829						
16	Accum Def Tax (Avg)	Ln 15 / 2	20,914						
17	Income Tax	Ln 12 * .27004		90,540					
18	Rate Bate		12,882,972						
19	Authorized ROR from UG 347		7.33%						
20	NOI	(Ln 18 * Ln 19) + (Ln 12 - Ln 17)	$944,322	$244,744					
21	Total NOI	(Ln 18 * Ln 19) + (Ln 12 - Ln 17)		$1,189,066					
22	Conversion Factor from Company Testimony in UG 347			0.70725					
23	Revenue Requirement	Ln 21 / Ln 22		**$1,681,253**					
24	Allocation Rev Req to Schedules	Ln 23 * Ln 19		$837,668	$504,639	$68,925	$18,637	$11,323	$240,061
25	Weather Normalized 2019 Volumes (Same as PGA)			42,977,440	30,286,424	2,037,630	1,629,956	2,418,468	201,091,680
26	Rate Change	Ln 24 / Ln 25		$0.01949	$0.01666	$0.03383	$0.01143	$0.00468	$0.00119
27	2018 Spring Earnings Review Total Revenue (For sample 2017 is shown)			$73,859,618					
28	Percentage Increase in Revenue	Ln 23 / Ln 27		2.28%					

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

Cascade Natural Gas Corporation

Direct Testimony of Maryalice C. Peters

EXHIBIT 300

May 31, 2018

EXHIBIT 300 – DIRECT TESTIMONY

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Maryalice C. Peters. My business address is 8113 W. Grandridge Blvd., Kennewick, Washington 99336-7166. My e-mail address is maryalice.peters@cngc.com.

Q. By whom are you employed, how long, and in what capacity?

A. I am employed by Cascade Natural Gas Corporation (Cascade or Company) as Regulatory Analyst III, and have been with the Company since December 2010. In this capacity, I prepare regulatory reports and rate/tariff filings for regulatory approval, as well as provide regulatory and tariff advice and knowledge to others within the Company.

Q. What are your educational and professional qualifications?

A. I am a 2009 graduate of Washington State University with a B.A. in Management and Operations. In 2012, I attended a seminar on basic rates put on by the American Gas Association (AGA) at the University of Chicago. I have attended other pertinent conferences such as the Annual Staff Subcommittee on Accounting sponsored by the National Association of Regulatory Utility Commissioners (NARUC) in 2013 as well as other NARUC-sponsored events.

I have testified before the Washington Utilities & Transportation Commission (WUTC) on behalf of Cascade in Docket UG 170929.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this docket?

A. The purpose of my testimony is to present the Company's proposed revenue requirement and supporting calculations.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. I am sponsoring the following exhibits, which are described in my testimony:

- Exhibit CNGC/301 Results of Operation Summary Sheet
- Exhibit CNGC/302 Revenue Requirement Calculation
- Exhibit CNGC/303 Conversion Factor Calculation
- Exhibit CNGC/304 Proposed Adjustments to Base Year Results
- Exhibit CNGC/305 2018 Plant Additions
- Exhibit CNGC/306 Decoupling Allowed Margin per Customer

III. REVENUE REQUIREMENT AND SUPPORTING CALCULATIONS

Q. Please summarize the results of the proposed revenue requirement for the Oregon jurisdiction.

A. After taking into account all proposed adjustments, Cascade's anticipated rate of return (ROR) is 5.85%, as shown in Exhibit CNGC/301. The incremental revenue necessary to achieve the recommended ROR of 7.33% is $2,310,808 also shown in Exhibit CNGC/301. The calculation of the incremental revenue is also provided in Exhibit CNGC/302. The overall base revenue increase requested is 3.53%.

Q. Please explain the Company's results of operations presented in Exhibit CNGC/301.

A. The Company's results of operations are summarized in Exhibit CNGC/301. The figures shown in column (1) are the actual Oregon booked figures for the base year, which is the twelve months ended December 31, 2017. Column (2) is the summation of all adjustments, both restating and forecasted, to achieve the test period results. Each adjustment that is included in column (2) is identified separately in Exhibit CNGC/304, and is described later in my testimony. Column (3) is the sum of columns (1) and (2), and represents the expected results of operations in the test period absent any rate change. Column (4) identifies the proposed revenue change and the net income impact of the revenue increase.[1] Column (5) is the results of operation expected during the test period with proposed rates.

Q. What is the Company's proposed test year for this case?

A. Cascade is proposing calendar year 2018 as the test period. As a practical matter, rates are anticipated to go into effect April 1, 2019; consequently, 2019 will be the first year rates will be in effect. However, we are unable to accurately project 2019 revenues and costs at this time.

Q. Does the Company anticipate adjusting the test period later in this docket?

A. No. Although costs are anticipated to exceed growth in revenues from new customers in 2019, Cascade is opting to keep this filing as simple as possible by excluding such projections.

Q. Are 2019 revenue increases due to increased customers expected to offset 2019 expected cost increases?

A. No. As a demonstration; if margin revenue increased by 1%, which is a reasonable expectation, the increase in margin revenue would be approximately $300,000. A typical wage increase of 4% would offset half that amount while a simple inflation calculation would offset the remaining half. For this reason, the selection of a 2018 test year yields conservative results.

Q. What is your total revenue requirement?

A. Our total revenue requirement is $111,129,333, which includes a proposed revenue increase of $2,310,808 to achieve the Company's proposed rate of return of 7.33%. The Company's calculation of its revenue requirement is found in Exhibit CNGC/302.

[1] The proposed revenue increase is also calculated in Exhibit CNGC/302.

Q. Please explain the adjusted revenues on line 8 of Exhibit CNGC/302.

A. The total is from Exhibit CNGC/301, column (3), line 4.

Q. Please explain the conversion factor found on line 6 of Exhibit CNGC/303.

A. Exhibit CNGC/303 shows the calculation of the conversion factor which is applied to the required net income to produce the required revenue increase. The conversion factor takes into account revenue-sensitive items that change as revenue changes, including uncollectibles, franchise taxes, Commission fees, Oregon state income tax, and federal income taxes. The conversion factor is 0.70725.

Q. Would you describe each of the adjustments included in Exhibit CNGC/304?

A. Yes. The first column, column (a), entitled "Uncollectibles Expense" is an adjustment to test period booked uncollectibles expense to reflect an average of the last three years of actual net bad debt write-offs. This adjustment is consistent with the Type I adjustment in Cascade's annual earnings report. The result is an increase in net income of $31,791.

Column (b), entitled "Removal 50% Membership Fees" adjusts 50% of booked membership fees consistent with the Type I adjustment in Cascade's annual earnings report. The result is an increase in net income of $24,581.

Column (c), entitled "Promotional Advertising Adjustment" removes all base year advertising. The Commission's administrative rules establish ratemaking categories for various types of utility advertising expenses.[2] Cascade removed all promotional advertising expense booked to FERC account 913 along with all Category C advertising. The result is an increase in net income of $8,382.

Column (d), entitled "Interest Coordination Adjustment" adjusts federal income tax for the effect of the average debt rate used to calculate the rate of return

[2] *See* OAR 860-026-0022.

applied to the proposed rate base shown in Exhibit CNGC/301, column (3), line 27. This adjustment is again consistent with the Type I adjustment in Cascade's annual earnings report. The result is an increase in net income of $53,858. The income tax effect is reflective of the new 21 percent tax rate.

Column (e), entitled "PGA Commodity Sharing Adj." adjusts gas costs to reflect the amount of Purchase Gas Adjustment (PGA) commodity sharing that was accrued or booked during the base year. Cascade is increasing earnings to add the sharing loss booked by the Company of $198,081 during 2016 as a result of commodity costs being greater than those built into the PGA. The result of this adjustment is an increase in net operating income of $144,591.

Column (f), entitled "Annualizing Wage Rate Adjustment" reflects the full year impact for 2017 of the union contract wage increase that was effective April 1, 2017. This adjustment reduces net income by $21,717.

Column (g), entitled "2018 Revenue Adjustment' adds margin revenue to account for the additional customers at weather normalized loads to be added during 2018. This adjustment also reflects final rates authorized in docket UG 305 on projected loads. This adjustment increases net income by $815,654.

Column (h), entitled "2018 Wage Adjustment" reflects the actual wage adjustment applied to non-union and union employees. Non-union wage increases were effective January 1, 2018, and union increases typically effective on April 1. The non-union increase granted was 4% and the union increase on June 14, 2018 will be 3%. This adjustment decreases net income by $166,057.

Column (i), entitled "2018 New Positions" reflects additional employees that have already or will be added during 2018. The Company is anticipating a net increase of 7 additional positions in 2018 on a system basis. The majority of these new positions are for crew to support the maintenance and construction of our natural gas operations. Additionally, with the creation of a new Integrity Management department and a record capital budget, a new Engineer position was needed to be able to provide continued reliability and project execution. The net effect of this adjustment is a decrease on net income of $186,691.

Column (j), entitled "Officer Incentive Comp Adj" removes all incentive compensation paid to the executive group. This adjustment is also consistent with the Type I adjustment in Cascade's annual earnings report. The result is an increase in net income of $225,582.

Column (k), entitled "2018 Plant Additions" provides the Company's budgeted level of capital additions expected to go into service during 2018. The majority of the projected investments are non-revenue producing. The Company will update this projection later in the case to reflect actual costs and more up-to-date estimates. The net income effect of the rate base additions, for depreciation expense and property taxes, is a decrease of $458,133. The rate base impact is an increase of $23,862,892.

Column (l), entitled "Inflation Factor Adj" shows the impact of applying a consumer price index (CPI) inflation factor to non-labor related expenses. The net income effect is a decrease of $101,050.

Column (m), entitled "Miscellaneous Charge Changes" accounts for proposed changes to certain miscellaneous fees in Schedule 200. Cascade witness Ms. Jennifer G. Gross describes the proposed changes in greater detail in Exhibit CNGC/500. This adjustment increases net income by $17,982.

Column (n), entitled "Depreciation Expense Adj" shows the impact of the depreciation rates for 2018. The resolution of docket UM 1727 resulted in new depreciation rates effective January 1, 2016. The impact of applying the authorized depreciation rates to actual plant as of December 31, 2017, is an increase to depreciation expense of $240,129. This results in a decrease to net income of $175,285.

Column (o), entitled “A&G Adjustment” provides removal of miscellaneous administrative and general expenses not appropriate for recovery through customer rates. Cascade performed an analysis for Non-Labor costs recorded in all FERC accounts for Base Year, Standard Data Request 57, to determine booked expenses inappropriate for rate recovery. This adjustment increases net income by $4,113.

Column (p), entitled “TCJA Impact” reflects the impacts of change of the Tax Cuts and Jobs Act (TCJA) reducing the corporate tax rate from 35% to 21%. Cascade witness Mr. Michael P. Parvinen describes the proposed changes in greater detail in Exhibit CNGC/200. This adjustment increases net income by $1,157,631.

Column (q), entitled “UM 1816 Deferral Amortization” shows the impact of Cascade’s proposed amortization of deferred costs associated with work performed by third-party contract to review and verify Cascade’s records regarding maximum allowable operating pressures (MAOP) for its high-pressure distribution and transmission pipelines. Further testimony describing the proposal can be found later in my testimony. The net income affect is a decrease of $85,204.

Column (r), entitled “Rate Case Costs” reflects the impacts of incremental costs associated with filing this general rate case. These costs will be updated later in the case as they become known and better estimated. The net income impact is a decrease of $65,456.

IV. 2018 PLANT ADDITIONS

Q. Are plant additions a significant driver for Cascade's request for a rate increase?

A. Yes. Cascade's 2018 plant additions account for $3,119,251 of the total revenue requirement increase of $2,321,469. The increased rate base accounts for more than the total request which is offset by reductions in tax expense due to the TCJA.

Q. What plant additions are planned for 2018?

A. Attached as Exhibit CNGC/305 is a list of all the projects planned for 2018. This list includes a brief project description and an estimated cost. The projected costs and schedules for these projects will be updated as actual costs and in-service dates become known.

Q. Will these projects be in-service and used and useful prior to the conclusion of this docket?

A. Yes. In fact, the adjustment only includes projects that will be in-service by the end of 2018, three months prior to the conclusion of this docket. As mentioned previously, these projects and estimated costs will be updated to only include actual costs and projects in service by the end of 2018.

V. ALLOWED MARGIN FOR DECOUPLING MECHANISM

Q. Have you prepared an exhibit showing the allowed margin per customer as determined from Cascade's proposed revenue, customers, and volumes?

A. Yes, Exhibit CNGC/306.

Q. Please describe Exhibit CNGC/306 and how it will be used after the conclusion of this docket?

A. The monthly average margin per customer shown on this exhibit will be applied to actual customers to derive the allowed revenue per customer to be collected. The difference from the allowed revenue and actual revenue charged to customers will be deferred as per Cascade's approved Decoupling mechanism.

Q. Does this conclude your testimony?

A. Yes it does.

CNGC/301
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MARYALICE C. PETERS
Exhibit No. 301

Results of Operation Summary Sheet

Cascade Natural Gas
Results of Operation Summary Sheet
UG 347
Twelve Months Ended December 31, 2017

	SUMMARY SHEET	2017 Results Per Company Filing (1)	Summary of Adjustments (2)	Test Year Adjusted Total (3)	Requested Revenue Increase (4)	Adjusted Results After Proposed Revenues (5)
	Operating Revenues					
1	Natural Gas Sales	59,895,194	1,233,251	61,128,445	2,310,808	63,439,253
2	Gas Transportation Revenue	4,114,883	(80,421)	4,034,462		4,034,462
3	Other Operating Revenues	264,704	24,715	289,419		289,419
4	SUBTOTAL	64,274,782	1,177,545	65,452,327	2,310,808	67,763,134
5	LESS: Nat. Gas/Production Costs	30,733,688	(198,081)	30,535,607		30,535,607
6	Revenue Taxes	3,015,262	31,695	3,046,957	63,531	3,110,488
7	**OPERATING MARGIN**	30,525,832	1,343,931	31,869,763	2,247,277	34,117,040
	Operating Expenses					
8	Production	101,025	1,717	102,743		102,743
9	Distribution	6,434,534	425,888	6,860,421		6,860,421
10	Customer Accounts	1,904,929	(7,349)	1,897,580	7,496	1,905,077
11	Customer Service	121,204	0	121,204		121,204
12	Sales	913	(11,482)	(10,569)		(10,569)
13	Administrative and General	6,213,010	49,491	6,262,500		6,262,500
14	Depreciation & Amortization	6,437,588	867,743	7,305,331		7,305,331
15	Regulatory Debits		0	0		0
16	Taxes Other Than Income	2,155,564	0	2,155,564		2,155,564
17	State & Federal Income Taxes	1,875,733	(1,206,649)	669,083	604,830	1,273,914
18	**Total Operating Expenses**	25,244,500	119,358	25,363,858	612,326	25,976,185
19	**Net Operating Revenues**	5,281,332	1,224,573	6,505,905	1,634,950	8,140,855
	Rate Base					
20	Total Plant in Service	219,983,640	24,552,055	244,535,695		244,535,695
21	Total Accumulated Depreciation	(102,088,918)	(7,305,331)	(109,394,249)		(109,394,249)
22	Contributions in Aid of Construction	0	0	0		0
23	Customer Adv. For Construction	(408,596)	0	(408,596)		(408,596)
24	Deferred Accumulated Income Taxes	(26,914,734)	498,717	(26,416,017)		(26,416,017)
25	Deferred Debits		0	0		0
26	Working Capital Allowance	2,812,500	0	2,812,500		2,812,500
27	**TOTAL RATE BASE**	93,383,892	17,745,441	111,129,333	0	111,129,333
28	**Rate of Return**	5.66%		5.85%		7.33%

CNGC/302
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MARYALICE C. PETERS
Exhibit No. 302

Revenue Requirement Calculation

Cascade Natural Gas
Revenue Requirement Calculation
UG 347
Twelve Months Ended December 31, 2017

1	Adjusted Rate Base	$111,129,333
2	Rate of Return	7.33%
3	Required Return (ln 1 x ln 2)	$8,140,224
4	Adjusted Net Income	$6,505,905
5	Required Net Income Increase (ln 3 - ln 4)	$1,634,319
6	Conversion Factor	0.70725
7	Revenue Increase Required (ln 5 / ln 6)	**$2,310,808**
8	Test Year Adjusted Revenue	$65,452,327
9	Overal Revenue Increase	**3.5305%**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MARYALICE C. PETERS
Exhibit No. 303

Conversion Factor Calculation

Cascade Natural Gas
Conversion Factor Calculation
UG 347
Twelve Months Ended December 31, 2018

Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00324
Taxes Other - Franchise	0.02449
OPUC Fees	0.00300
Interest expense	
State Taxable Income	0.96926
State Income Tax	0.07401
Federal Taxable Income	0.89525
Federal Income Tax @ 21%	0.18800
Total Income Taxes	0.26201
Total Revenue Sensitive Costs	0.29275
Net-to-Gross Factor	**0.70725**

Combo-State & Federal Income Tax	
State	0.07600
Federal	0.21000
State and Federal Effective Tax Rate	0.27004

CNGC/304
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MARYALICE C. PETERS
Exhibit No. 304

Proposed Adjustments to Base Year Results

Cascade Natural Gas
Proposed Adjustments to Base Year Results
UG 347
Twelve Months Ended December 31, 2018

		Uncollectibles Expense (a)	Removal 50% Membership Fees (b)	Promotional Advertising Adjustment (c)	Interest Coordination Adjustment (d)	PGA Commodity Sharing Adj. (e)	Annualizing Wage Rate Adjustment (f)	2018 Revenue Adjustment (g)	2018 Wage Adjustments (h)	2018 New Positions (i)	Officer Incentive Comp Adj (j)	2018 Plant Additions (k)	Inflation Factor Adj (l)	Miscellaneous Charge Changes (m)	Depreciation Expense Adj (n)	A&G Adjustment (o)	TCJA Impact (p)	UM 1816 Deferral Amortization (q)	Rate Case Costs (r)	**Total Adjustments (Base Rates) (s)**
1	**Operating Revenues**																			
2	Natural Gas Sales							$1,233,251					$0	$0	$0	$0	$0	$0		1,233,251
3	Gas Transportation Revenue							(80,421)					0	0	0	0	0	0		(80,421)
4	Other Operating Revenues												0	24,715	0	0	0	0		24,715
5	SUBTOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,152,830**	**$0**	**$0**	**$0**	**$0**	**$0**	**$24,715**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,177,545**
6	LESS: Nat. Gas/Production Costs					(198,081)														($198,081)
7	Revenue Taxes					0		31,695												$31,695
8	**OPERATING MARGIN**	**$0**	**$0**	**$0**	**$0**	**$198,081**	**$0**	**$1,121,135**	**$0**	**$0**	**$0**	**$0**	**$0**	**$24,715**	**$0**	**$0**	**$0**	**$0**	**$0**	$1,343,931
9																				$0
10	**Operating Expenses**																			$0
11	Production												1,717							$1,717
12	Distribution									255,755			53,408					116,724		$425,888
13	Customer Accounts	($43,552)				$0		$3,740					32,384	$80						($7,349)
14	Customer Service												0							$0
15	Sales			(11,482)																($11,482)
16	Administrative and General		(33,674)				29,751		227,488		(309,033)		50,923			(5,635)			89,670	$49,491
17	Depreciation & Amortization											627,614			240,129					$867,743
18	Regulatory Debits																			$0
19	Taxes Other Than Income																			$0
20	State & Federal Income Taxes	11,761	9,093	3,101	(53,858)	53,490	(8,034)	301,741	(61,431)	(69,064)	83,451	(169,481)	(37,382)	6,652	(64,844)	1,522	(1,157,631)	(31,520)	(24,214)	($1,206,649)
21	**Total Operating Expenses**	(31,791)	(24,581)	(8,382)	(53,858)	53,490	21,717	305,481	166,057	186,691	(225,582)	458,133	101,050	6,733	175,285	(4,113)	(1,157,631)	85,204	65,456	$119,358
22	**Net Operating Revenues**	$31,791	$24,581	$8,382	$53,858	$144,591	($21,717)	$815,654	($166,057)	($186,691)	$225,582	($458,133)	($101,050)	$17,982	($175,285)	$4,113	$1,157,631	($85,204)	($65,456)	$1,224,573
24	**Rate Base**																			
25	Total Plant in Service											24,552,055								$24,552,055
26	Total Accumulated Depreciation											(627,614)			(6,677,717)					($7,305,331)
27	Contributions in Aid of Construction																			$0
28	Customer Adv. For Construction																			$0
29	Deferred Accumulated Income Taxes											(61,548)					560,266			$498,717
30	Deferred Debits																			$0
31	Working Capital Allowance																			$0
32	**TOTAL RATE BASE**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$23,862,892	$0	$0	($6,677,717)	$0	$560,266	$0	$0	$17,745,441
33																				
34	**Revenue Requirement Effect**	**($44,951)**	**($34,755)**	**($11,851)**	**($76,151)**	**($204,442)**	**$30,707**	**($1,153,276)**	**$234,793**	**$263,968**	**($318,956)**	**$3,119,251**	**$142,877**	**($25,426)**	**($443,773)**	**($5,816)**	**($1,578,780)**	**$120,472**	**$92,549**	**$106,441**

CNGC/305
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MARYALICE C. PETERS
Exhibit No. 305

2018 Plant Additions

Cascade Natural Gas
2018 Plant Additions
UG 347
Twelve Months Ended December 31, 2017

Line No.	Function	Funding Project	Description	Account No.	2018 Total - Figures exported from "Power Plan" the company's budget and plant accounting software	OR
1	Gas Intangible	FP-101209	INTANGIBLES - SOFTWARE	303.00	18,382.29	18,382.29
2	Gas Intangible	FP-101472	UG-PIM Installation	303.00	63,025.00	63,025.00
3	Gas Intangible	FP-101480	UG-Work Asset Management	303.00	162,285.49	162,285.49
4	Gas Intangible	FP-200064	UG-Customer Self-Service Web/IVR	303.00	13,471.84	13,471.84
5	Gas Intangible	FP-200663	UG-GIS Enhancements	303.00	29,619.92	29,619.92
6	Gas Intangible	FP-315865	UG - ThoughtSpot Implementation Prj	303.00	71,006.09	71,006.09
7	Gas Intangible	FP-316269	UG - JDE Weblogic - CNGC	303.00	6,283.13	6,283.13
8	Gas Intangible	FP-316289	UG - PowerPlan Lease - CNGC	303.00	32,936.97	32,936.97
9	Gas Intangible	FP-316361	UG-GAS SCADA System Enhancements	303.00	14,870.27	14,870.27
10	Gas Intangible	FP-316447	UG-PragmaFIELD Implementation	303.00	35,732.54	35,732.54
11	Gas Intangible	FP-316451	UG-PCAD Annual Enhancements	303.00	18,487.42	18,487.42
29			**Total Intangible Plant**		466,100.95	466,100.95
30	RESULTS OF OPERATIONS SUMMARY SHEET					
31	Gas Distribution	FP-101170	MAIN-GROWTH-OREGON	376.00	537,045.16	537,045.16
32	Gas Distribution	FP-200688	Bend Pipe Replacement Phase 7	376.00	1,829,867.08	1,829,867.08
33	Gas Distribution	FP-303142	Pendleton Pipe Replacement Phase 2	376.00	1,984,265.99	1,984,265.99
34	Gas Distribution	FP-316697	RP; 4" ST; Bend; 2,500' PH 7 Sec 1	376.00	1,203,283.66	1,203,283.66
35	Gas Distribution	FP-101171	MAIN-REINFORCE-OREGON	376.00	79,676.84	79,676.84
36	Gas Distribution	FP-101172	MAIN-RELO-REPL-OREGON	376.00	418,760.63	418,760.63
37	Gas Distribution	FP-200689	RPL; 6" HP, BEND HP PH1	376.00	1,789,561.33	1,789,561.33
38	Gas Distribution	FP-306989	UMATILLA 2" REINFORCEMENT	376.00	992,811.14	992,811.14
39	Gas Distribution	FP-306997	RPL; 4" HP, MADRAS PH1	376.00	5,540,101.58	5,540,101.58
40	Gas Distribution	FP-316479	Bend River Mall Main RPL Bend	376.00	14,985.34	14,985.34
41	Gas Distribution	FP-302370	GB - GROUNDBED OREGON	376.00	298,291.84	298,291.84
42	Gas Distribution	FP-316430	RP; 2" BRIDGE XING, ATHENA	376.00	189,827.75	189,827.75
43	Gas Distribution	FP-316478	27th St Bore Canal Bend	376.00	110,367.33	110,367.33
44	Gas Distribution	FP-316480	Ward Rd Canal Bore	376.00	102,911.95	102,911.95
45	Gas Distribution	FP-101173	R STA-GROWTH-OREGON	378.00	99,840.60	99,840.60
46	Gas Distribution	FP-101175	R STA-RELO-REPL-OREGON	378.00	192,861.20	192,861.20
47	Gas Distribution	FP-316245	RP; O-TBD(O-4) BAKER CITY	378.00	124,179.92	124,179.92
48	Gas Distribution	FP-316246	RP; O-TBD(O-9) LA PINE	378.00	122,164.05	122,164.05
49	Gas Distribution	FP-101176	SERV-GROWTH-OREGON	380.00	1,417,460.32	1,417,460.32
50	Gas Distribution	FP-101177	SERV-RELO-REPL-OREGON	380.00	240,608.69	240,608.69
51	Gas Distribution	FP-101210	PRE-CAP MTR-GROWTH-INTERSTAT	381.00	803,545.40	803,545.40
52	Gas Distribution	FP-308022	ERT Replacement - 2018	381.00	3,485,554.13	3,485,554.13
53	Gas Distribution	FP-101178	STD M&R-GROWTH-OREGON	382.00	113,326.68	113,326.68
54	Gas Distribution	FP-101179	STD M&R-RELO-REPL-OREGON	382.00	458,371.87	458,371.87
55	Gas Distribution	FP-101259	PRE-CAP REG-GROWTH-INTERSTAT	383.00	132,900.51	132,900.51
56	Gas Distribution	FP-101180	IND M&R-GROWTH-OREGON	385.00	62,481.48	62,481.48
57	Gas Distribution	FP-101181	IND M&R-REMOVE&REPLACE-OREGON	385.00	65,866.32	65,866.32
58			**Total Distribution Plant**		22,410,918.79	22,410,918.79

Cascade Natural Gas
2018 Plant Additions
UG 347
Twelve Months Ended December 31, 2017

Line No.	Function	Funding Project	Description	Account No.	2018 Total - Figures exported from "Power Plan" the company's budget and plant accounting software	OR
59	Gas General	FP-101252	GP BUILDINGS - ONTARIO	390.00	11,047.05	11,047.05
60	Gas General	FP-101466	GP BUILDINGS - BEND	390.00	15,781.56	15,781.56
61	Gas General	FP-101213	GP BUILDINGS - INTERSTATE	390.00	1,969.52	1,969.52
62	Gas General	FP-200661	Data Center & Network Equipment	391.00	50,183.65	50,183.65
63	Gas General	FP-200662	Personal Computers & Peripherals	391.00	19,695.33	19,695.33
64	Gas General	FP-306967	District Office Access Control Sys	391.00	31,775.10	31,775.10
65	Gas General	FP-316445	Toughbook Replacements for Field	391.00	48,661.60	48,661.60
66	Gas General	FP-101184	GP TRAN. VEHICLE - OREGON	392.00	366,877.76	366,877.76
67	Gas General	FP-101215	GP TRAN. VEHICLE - INTERSTAT	392.00	12,771.76	12,771.76
68	Gas General	FP-101218	GP TOOLS - BEND	394.00	97,087.79	97,087.79
69	Gas General	FP-101237	GP TOOLS - PENDLETON	394.00	75,387.77	75,387.77
70	Gas General	FP-101255	GP TOOLS - ONTARIO	394.00	58,391.60	58,391.60
71	Gas General	FP-101216	GP TOOLS - INTERSTATE	394.00	69,829.38	69,829.38
72	Gas General	FP-316495	Turbine Prover	394.00	31,512.50	31,512.50
73	Gas General	FP-101186	GP POWER EQUIP - OREGON	396.00	730,721.28	730,721.28
74	Gas General	FP-101187	GP COMM EQUIP - OREGON	397.00	20,515.92	20,515.92
75	Gas General	FP-101164	General Purpose Communication Equip	397.00	32,825.52	32,825.52
76			**Total Distribution Plant**		1,675,035.10	1,675,035.10
77			**Total**		24,552,054.84	**24,552,054.84**

Line No.	FERC Acct	Budgeted 2018 Investment	Depr. Rate Order 15-315	Depreciation Expense	
78	**FERC**	**Budgeted 2018**	**Depr. Rate**	**Depreciation**	
79	**Acct**	**Investment**	**Order 15-315**	**Expense**	
80	303	466,100.95	10.00	46,610.09	
81	376-1	1,904,682.53	2.20	41,903.02	
82	376-2	9,357,956.68	1.25	116,974.46	
83	376-3	3,829,118.41	4.13	158,142.59	
84	378	539,045.77	1.92	10,349.68	
85	380	1,658,069.01	3.88	64,333.08	
86	381	4,289,099.54	2.27	97,362.56	
87	382	571,698.55	1.86	10,633.59	
88	383	132,900.51	2.32	3,083.29	
89	385	128,347.80	2.18	2,797.98	
90	390	28,798.13	1.24	357.10	
91	391	150,315.67	0.05	75.16	
92	392	379,649.52	6.15	23,348.45	
93	394	332,209.04	3.56	11,826.64	
94	396	730,721.28	5.18	37,851.36	
95	397	20,515.92	9.37	1,922.34	
96	397	32,825.52	0.13	42.67	
97		24,552,054.84		627,614.06	0.025562588

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

MARYALICE C. PETERS
Exhibit No. 306

Decoupling Allowed Margin Per Customer

Cascade Natural Gas
CAP Baseline
UG 347
Twelve Months Ended December 31, 2017

R/S 101	0.38815
R/S 104	0.23878

Cascade Natural Gas Corporation
Calculation of Baseline Monthly Commodity Margin Per Customer Based upon Weather Normalized Therm Sales

State Of Oregon

	Adjusted Therms	Actual Customers	Commodity Margin	Baseline Avg Commodity Margin/cust
Residential Rate Schedule 101				
Jan-18	7,005,738	62,524	$ 2,719,277.20	$ 43.49
Feb-18	5,633,667	62,577	$ 2,186,707.85	$ 34.94
Mar-18	4,817,743	62,641	$ 1,870,006.95	$ 29.85
Apr-18	3,313,200	62,521	$ 1,286,018.58	$ 20.57
May-18	2,145,812	62,392	$ 832,896.93	$ 13.35
Jun-18	1,309,198	62,282	$ 508,165.20	$ 8.16
Jul-18	981,197	62,146	$ 380,851.62	$ 6.13
Aug-18	989,382	62,079	$ 384,028.62	$ 6.19
Sep-18	1,328,711	62,059	$ 515,739.17	$ 8.31
Oct-18	2,927,044	62,453	$ 1,136,132.13	$ 18.19
Nov-18	5,163,188	62,912	$ 2,004,091.42	$ 31.86
Dec-18	7,362,560	63,327	$ 2,857,777.66	$ 45.13
Total	42,977,440	749,913	$ 16,681,693.34	**$ 266.17**
Average		62,493		
Commercial Rate Schedule 104				
Jan-18	4,650,113	10,049	$ 1,110,353.98	$ 110.49
Feb-18	3,798,979	10,062	$ 907,120.21	$ 90.15
Mar-18	3,107,040	10,075	$ 741,899.01	$ 73.64
Apr-18	2,135,536	10,057	$ 509,923.29	$ 50.70
May-18	1,542,375	10,043	$ 368,288.30	$ 36.67
Jun-18	1,121,001	10,019	$ 267,672.62	$ 26.72
Jul-18	957,089	9,985	$ 228,533.71	$ 22.89
Aug-18	999,130	9,957	$ 238,572.26	$ 23.96
Sep-18	1,189,447	9,949	$ 284,016.15	$ 28.55
Oct-18	2,140,546	9,981	$ 511,119.57	$ 51.21
Nov-18	3,650,844	10,059	$ 871,748.53	$ 86.66
Dec-18	4,994,323	10,141	$ 1,192,544.45	$ 117.60
Total	30,286,423	120,377	$ 7,231,792.08	**$ 719.24**
Average		10,031		

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

Cascade Natural Gas Corporation

Direct Testimony of Isaac D. Myhrum

EXHIBIT 400

May 31, 2018

EXHIBIT 400 – DIRECT TESTIMONY

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address, and present position with Cascade Natural Gas Corporation.

A. My name is Isaac D. Myhrum and my business address is 8113 W. Grandridge Blvd., Kennewick, WA 99336. My present position is Regulatory Analyst I in the Regulatory Affairs Department.

Q. Would you briefly describe your duties?

A. Yes. I prepare regulatory reports and filings on behalf of the Company for both the Public Utility Commission of Oregon (OPUC) and Washington Utilities and Transportation Commission (WUTC). I also perform analysis of the regulatory filings submitted by the company to these commissions and other regulatory agencies.

Q. How long have you been employed by the Company?

A. I have been employed by the Company since August 2016.

Q. Would you please briefly describe your educational background and professional experience?

Yes. I hold a Bachelor of Arts degree in Accounting and Business Administration from Washington State University. I also hold a Bachelor of Science degree in Political Science with an emphasis in Economics from the University of Idaho. I attended New Mexico State University's Center for Public Utilities Rate School in October 2016 and have attended other utility-specific trainings, and conferences. Prior to joining the Company I worked as a staff accountant for two public accounting firms in the Tri-Cities, Washington area.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to describe the revenue proof shown in Exhibit CNGC/401.

II. REVENUE PROOF

Q. Would you please describe the revenue proof shown in Exhibit CNGC/401?

A. Yes. The revenue proof provides a comparison of revenues at current rates with those the Company expects under proposed rates. Exhibit CNGC/401 presents the Company's Per Books Revenue for the twelve months ending December 31, 2017 broken out by rate schedule ("Per Books Revenue" labeled column "(D)"). The Per Books Revenue amounts include all the components of the current rates, including gas costs, non-gas costs, taxes, the public purpose charge and any billing adjustments for each rate schedule. The Per Books Revenue total matches the 2017 total operating revenues subtotal presented in Company witness Maryalice Peters' testimony.[1]

In order to provide an "apples-to-apples" comparison between current and proposed rates an adjustment to Per Books Revenue is made to true up to future test year conditions ("Revenue Adjustment" labeled column "(F)"). The revenue adjustment is derived by annualizing 2017 revenues to reflect the rate changes that were effective March 1, 2017 for Rate Schedules 101, 104, 105, and 111, and the rate changes that were effective November 1, 2017 for Rate Schedules 902, 903, 904 and 905. Additionally, billing determinants (bills and therms) have been adjusted to equal forecasted amounts in the future test year. The combined revenue adjustments for all rate classes presented in Exhibit CNGC/401 matches the before-tax 2017 Revenue Adjustment subtotal presented in Company witness Maryalice Peters' testimony.[2]

Both current and proposed rates are applied to these forecasted billing

[1] CNGC/301, "2017 Results Per Company Filing" Column (1)
[2] CNGC/304, Subtotal adjustment (g)

determinants for comparison purposes ("Revenue at Current Rates labeled column "(H)" and "Revenue at Proposed Rates" labeled column "(J)", respectively). The dollar impact of these changes, by rate schedule, are presented in the final column labeled "Increase". This final column represents the amount of the revenue increase in rates each tariff class will receive as a result of the difference between current and proposed rates.

Q. Will you further describe the Revenue Adjustment in "Column F"?

A. Yes. As mentioned previously, changes to volumetric delivery and basic service charges went into effect for many Oregon customers on March 1, 2017. The rate revisions were the result of Company's last general rate case in Oregon.[3]

In order to annualize 2017 revenues at March 1, 2017 rates, the revenues associated with the months prior to the rate revision (January and February 2017) are restated at the March 1, 2017 rates. To achieve this restatement, the revenue from January and February 2017 are decremented from the Per Books Revenue in column "(F)" and the associated billing determinants (bills and therms) are multiplied by the current rates to calculate the revenue added back for the annualizing adjustment. In addition to the annualizing adjustment, the billing determinants are adjusted to forecasted number of bills and weather normalized volumes and then applied to the respective basic service charges and volumetric rates effective March 1, 2017. The net effect of these calculations is the total Revenue Adjustment.

Q. What is shown in the Pro Forma section of the revenue proof?

A. The pro-forma section shows current rates being applied to the forecasted billing determinants.

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[3] *See In the Matter of Cascade Natural Gas Corp. Request for a Gen. Rate Revision*, Docket No. UG 305, Order No. 16-477 (Dec. 12, 2016).

Q. What is shown in the proposed rates section of the revenue proof?

A. The proposed rates section shows the proposed rates being applied to the forecasted billing determinants.

Q. What is the source for the forecasted billing determinants used in this revenue proof?

A. The forecasted volumes and number of bills (customers) used in this revenue proof are found in the Company's 2018 Oregon Integrated Resource Plan (IRP).[4]

Q. Has the Company made any type of adjustment because it has used these forecasted billing determinants?

A. Yes. The use of these forecasted amounts forms the basis of an adjustment to the revenue requirement which is addressed further in Company witness Maryalice Peters' testimony.[5]

Q. What does the difference in the proposed rates and current rates show?

A. The difference between the proposed rates and current rates shows the revenue increase the Company is requesting in this case.

Q. Does this conclude your testimony?

A. Yes.

[4] *See In the Matter of Cascade Natural Gas Corp., 2018 Integrated Resource Plan, Docket No. LC 69, Appendix B (Feb. 06, 2018)*

[5] CNGC/301, "Requested Revenue Increase" Column (4)

CNGC/401
Myhrum

BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

ISAAC D. MYHRUM
Exhibit No. 401

Revenue Proof

Cascade Natural Gas Corporation
Revenue Proof

		Current			Future Test Year Adjustments		Pro Forma		Proposed		
Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)=(C)*(E)	(G)=(B)+(E)	(H)=(C)*(G)	(I)	(J)=(G)*(I)	(K)=(J)-(H)
1	**Rate Schedule 101 - General Residential Service**										
2	Basic Service Charge - Jan-Feb	124,767	$3.00	$374,301	(124,767)	-$374,301					
3	Basic Service Charge - Current	622,408	$4.00	$2,489,631	127,505	$510,021	749,913	$2,999,652	$5.00	$3,749,565	
4	Delivery Charge - Jan-Feb	17,190,365	$0.368840	$6,340,494	(17,190,365)	-$6,340,494					
5	Delivery Charge - Current	30,808,533	$0.364070	$11,216,463	12,168,906	$4,430,334	42,977,440	$15,646,797	$0.388150	$16,681,693	
6	Total Margin			$20,420,889		-$1,774,441		$18,646,449		$20,431,258	$1,784,810
7	Average Cost of Gas			$17,149,553							
8	Non-Gas Revenue										
9	Adjustment			-$403							
10	Franchise Tax			$691,295							
11	PPC and Adjustments			-$15							
12	Public Purpose Fund			$1,829,316							
13	Subtract out PPC Fund & Ajustments			-$1,829,302							
14	Current Month Unbilled +			$24,695,721		-$24,695,721					
15	Previous Month Unbilled -			-$25,148,739		$25,148,739					
16	CAP Adjustment			-$2,015,888		$2,015,888					
17	Deferrals			-$267,218		$267,218					
18	Deficiency			$0		$0					
19	Total Non-Gas Revenue			-$2,045,231		$2,736,123					
20	**Total Rate Schedule 101 Revenue**			$35,525,211		$961,683					
21	**Rate Schedule 104 - General Commercial Service**										
22	Basic Service Charge - Jan-Feb	20,011	$3.00	$60,033	(20,011)	-$60,033					
23	Basic Service Charge - Current	98,123	$4.00	$392,492	22,254	$89,016	120,377	$481,508	$10.00	$1,203,770	
24	Delivery Charge	32,857,955	$0.262630	$8,629,485	(2,571,530)	-$675,361	30,286,424	$7,954,124	$0.238780	$7,231,792	
25	Total Margin			$9,082,009		-$646,378		$8,435,632		$8,435,562	-$69
26	Average Cost of Gas			$11,713,225							
27	Non-Gas Revenue										
28	Adjustment			-$31,856							
29	Franchise Tax			$418,017							
30	PPC and Adjustments			-$1,537							

		Current			Future Test Year Adjustments		Pro Forma		Proposed		
Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)=(C)*(E)	(G)=(B)+(E)	(H)=(C)*(G)	(I)	(J)=(G)*(I)	(K)=(J)-(H)
31	Public Purpose Fund			$1,012,475							
32	Subtract out PPC Fund & Ajustments			-$1,010,937							
33	Current Month Unbilled +			$14,611,015		-$14,611,015					
34	Previous Month Unbilled -			-$14,686,575		$14,686,575					
35	CAP Adjustment			-$1,183,833		$1,183,833					
36	Deferrals			-$160,867		$160,867					
37	Deficiency			$897		-$897					
38	Total Non-Gas Revenue			-$1,033,202		$1,419,363					
39	**Total Rate Schedule 104 Revenue**			$19,762,032		$772,986					
40	**Rate Schedule 105 - General Industrial Service**										
41	Basic Service Charge	1,698	$12.00	$20,376	78	$936	1,776	$21,312	$30.00	$53,280	
42	Delivery Charge - Jan-Feb	954,994	$0.191520	$182,900	(954,994)	-$182,900					
43	Delivery Charge - Current	2,130,935	$0.205570	$438,056	(93,305)	-$19,181	2,037,630	$418,876	$0.236700	$482,307	
44	Total Margin			$641,333		-$201,145		$440,188		$535,587	$95,399
45	Average Cost of Gas			$1,096,951							
46	Non-Gas Revenue										
47	Adjustment			-$98							
48	Franchise Tax			$40,706							
49	Public Purpose Fund			$84,653							
50	PPC and Adjustments			-$5							
51	Subtract out PPC Fund & Ajustments			-$84,648							
52	Deferrals			-$4,643		$4,643					
53	Deficiency			$114,831		-$114,831					
54	Total Non-Gas Revenue			$150,797		-$110,188					
55	**Total Rate Schedule 105 Revenue**			$1,889,081		-$311,333					
56	**Rate Schedule 111 - Large Volume Firm Commercial Service**										
57	COMMERCIAL										
58	Basic Service Charge	108	$0.00		-	$0	108	$0	$125.00	$13,500	
59	Delivery Charge - Jan-Feb	289,909	$0.154940	$44,919	(289,909)	-$44,919	-	$0			
60	Delivery Charge - Current	571,475	$0.165920	$94,819	(55,656)	-$9,234	515,819	$85,585	$0.149360	$77,043	
61	Total Margin			$139,738		-$54,153		$85,585		$90,543	$4,958

Cascade Natural Gas Corporation
Revenue Proof

		Current			Future Test Year Adjustments		Pro Forma		Proposed		
Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)=(C)*(E)	(G)=(B)+(E)	(H)=(C)*(G)	(I)	(J)=(G)*(I)	(K)=(J)-(H)
62	Average Cost of Gas			$305,386							
63	Non-Gas Revenue										
64	Adjustment			-$36							
65	Franchise Tax			$4,363							
66	Public Purpose Fund			$21,678							
67	PPC and Adjustments			-$2							
68	Subtract out PPC Fund & Ajustments			-$21,676							
69	Deferrals			-$2,703		$2,703					
70	Deficiency			$0		$0					
71	Total Non-Gas Revenue			$1,624		$2,703					
72	INDUSTRIAL										
73	Basic Service Charge	108	$0.00	$0	-	$0	108	$0	$125.00	$13,500	
74	Delivery Charge - Jan-Feb	463,216	$0.154940	$71,771	(463,216)	-$71,771	-	$0			
75	Delivery Charge - Current	1,288,838	$0.165920	$213,844	(174,702)	-$28,987	1,114,136	$184,857	$0.149360	$166,407	
76	Total Margin			$285,615		-$100,757		$184,857		$179,907	-$4,950
77	Average Cost of Gas			$621,108							
78	Non-Gas Revenue										
79	Adjustment										
80	Franchise Tax			$9,552							
81	Public Purpose Fund			$44,157							
82	PPC and Adjustments										
83	Subtract out PPC Fund & Ajustments			-$44,157							
84	Deferrals			-$1,297		$1,297					
85	Deficiency			$0		$0					
86	Total Non-Gas Revenue			$8,256		$1,297					
87	**Total Rate Schedule 111 Revenue**			$1,361,725		-$150,910					
88	**Rate Schedule 170 - Interruptible Service**										
89	Basic Service Charge	48	$0.00	$0	-	$0	48	$0	$300.00	$14,400	
90	Delivery Charge	2,864,494	$0.123090	$352,591	(446,026)	-$54,901	2,418,468	$297,689	$0.117140	$283,299	
91	Total Margin			$352,591		-$54,901		$297,689		$297,699	$10

Cascade Natural Gas Corporation
Revenue Proof

		Current			Future Test Year Adjustments		Pro Forma		Proposed		
Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)=(C)*(E)	(G)=(B)+(E)	(H)=(C)*(G)	(I)	(J)=(G)*(I)	(K)=(J)-(H)
92	Average Cost of Gas			$1,005,796							
93	Non-Gas Revenue										
94	Adjustment			$1,109							
95	Franchise Tax			$13,378							
96	Public Purpose Fund			$66,153							
97	PPC and Adjustments			$53							
98	Subtract out PPC Fund & Ajustments			-$66,207							
99	Deferrals			-$4,217		$4,217					
100	Deficiency			$0		$0					
101	Previous Month CA1501A -			-$1,371,765		$1,371,765					
102	Current Month CA1501A +			$1,360,253		-$1,360,253					
103	Total Non-Gas Revenue			-$1,242		$15,729					
104	**Total Rate Schedule 170 Revenue**			$1,357,145		-$39,173					

Cascade Natural Gas Corporation
Revenue Proof

		Current			Future Test Year Adjustments		Pro Forma		Proposed		
Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)=(C)*(E)	(G)=(B)+(E)	(H)=(C)*(G)	(I)	(J)=(G)*(I)	(K)=(J)-(H)
105	<u>**Rate Schedule 163 - Interruptible Transportation**</u>										
106	Dispatch Service Charge	384	$500.00	$192,000	-	$0	384	$192,000	$625.00	$240,000	
107	Contract Demand Charge		n/a				1,674,720	$0	$0.10000	$167,472	
108	Commodity Charge										
109	First 10,000 Therms	3,433,070	$0.124020	$425,769	(53,235)	-$6,602	3,379,835	$419,167	$0.137520	$464,795	
110	Next 10,000 Therms	2,746,005	$0.111880	$307,223	(180,387)	-$20,182	2,565,618	$287,041	$0.124060	$318,291	
111	Next 30,000 Therms	5,087,291	$0.105120	$534,776	(663,759)	-$69,774	4,423,532	$465,002	$0.116560	$515,607	
112	Next 50,000 Therms	4,953,007	$0.064560	$319,766	(845,830)	-$54,607	4,107,177	$265,159	$0.071590	$294,033	
113	Next 400,000 Therms	17,357,111	$0.032750	$568,445	(1,659,991)	-$54,365	15,697,119	$514,081	$0.036310	$569,962	
114	Next 500,000 Therms	1,995,789	$0.017550	$35,026	(616,547)	-$10,820	1,379,242	$24,206	$0.019460	$26,840	
115	Over 1,000,000 Therms	-	$0.017550	$0	-	$0	-	$0	$0.001423	$0	
116	Total Margin			$2,383,006		-$216,350		$2,166,656		$2,597,000	$430,344
117	Average Cost of Gas			$0							
118	Non-Gas Revenue										
119	Adjustment			-$173							
120	Franchise Tax			$25,199							
121	Gross Revenue Fee			$62,402							
122	Deferrals			-$54,868		$54,868					
123	Previous Month CA1501A -			-$2,470,607		$2,470,607					
124	Current Month CA1501A +			$2,470,156		-$2,470,156					
125	Total Non-Gas Revenue			$32,108		$55,319					
126	**Total Rate Schedule 163 Revenue**			$2,415,115		-$161,031					
127	<u>**Rate Schedule 902 - Interruptible Transportation**</u>										
128	Dispatch Service Charge	12	$500.00	$6,000	-	$0	12	$6,000			
129	Contract Demand Charge	10,800,000	$0.1005555	$1,085,999	-	$0	10,800,000	$1,085,999			
130	Delivery Charge (Jan-Oct)	107,665,138	$0.0015412	$165,934	(107,665,138)	-$165,934	-				
131	Delivery Charge - Current	25,288,007	$0.0015659	$39,598	144,251,150	$225,883	169,539,157	$265,481			
132	**MIGRATE TO RATE SCHEDULE 163**										
133	Dispatch Service Charge		n/a				12		$625.00	$7,500	
134	Contract Demand Charge		n/a				7,184,880		$0.10000	$718,488	
135	Commodity Charge		n/a								
136	First 10,000 Therms		n/a				120,000		$0.137520	$16,502	

		Current			Future Test Year Adjustments		Pro Forma		Proposed		
Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)=(C)*(E)	(G)=(B)+(E)	(H)=(C)*(G)	(I)	(J)=(G)*(I)	(K)=(J)-(H)
137	Next 10,000 Therms		n/a				120,000		$0.124060	$14,887	
138	Next 30,000 Therms		n/a				360,000		$0.116560	$41,962	
139	Next 50,000 Therms		n/a				600,000		$0.071590	$42,954	
140	Next 400,000 Therms		n/a				4,800,000		$0.036310	$174,288	
141	Next 500,000 Therms		n/a				6,000,000		$0.019460	$116,760	
142	Over 1,000,000 Therms		n/a				157,539,157		$0.001423	$224,178	
143	Total Margin			$1,297,531		$59,949		$1,357,481		$1,357,519	$39
144	Non-Gas Revenue										
145	Adjustment			-$687							
146	Franchise Tax			$0							
147	Gross Revenue Fee			$33,962							
148	Previous Month CA1501A -			-$1,331,494		$1,331,494					
149	Current Month CA1501A +			$1,338,992		-$1,338,992					
150	Total Non-Gas Revenue			$40,773		-$7,498					
151	**Total Rate Schedule 902 Revenue**			$1,338,304		$52,452					

Cascade Natural Gas Corporation
Revenue Proof

		Current			Future Test Year Adjustments		Pro Forma		Proposed		
Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)=(C)*(E)	(G)=(B)+(E)	(H)=(C)*(G)	(I)	(J)=(G)*(I)	(K)=(J)-(H)
152	**<u>Rate Schedule 903 - Interruptible Transportation</u>**										
153	Dispatch Service Charge	12	$500.00	$6,000	-	$0	12	$6,000	$500.00	$6,000	
154	Contract Demand Charge	192,000	$0.0937500	$18,000	-	$0	192,000	$18,000	$0.093750	$18,000	
155	Delivery Charge (Jan-Oct)	7,077,305	$0.0118105	$83,587	(7,077,305)	-$83,587	-				
156	Delivery Charge - Current	1,089,731	$0.0119995	$13,076	7,254,245	$87,047	8,343,977	$100,124	$0.012000	$100,124	
157	Total Margin			$120,663		$3,461		$124,124		$124,124	$0
158	Non-Gas Revenue										
159	Adjustment			$202							
160	Franchise Tax			$0							
161	Gross Revenue Fee			$3,152							
162	Previous Month CA1501A -			-$123,815		$123,815					
163	Current Month CA1501A +			$123,129		-$123,129					
164	Total Non-Gas Revenue			$2,668		$685					
165	**Total Rate Schedule 903 Revenue**			$123,331		$4,146					
166	**<u>Rate Schedule 904 - Interruptible Transportation</u>**										
167	Dispatch Service Charge	12	$500.00	$6,000	-	$0	12	$6,000	$500.00	$6,000	
168	Contract Demand Charge	499,200	$0.0877404	$43,800	-	$0	499,200	$43,800	$0.087740	$43,800	
169	Delivery Charge (Jan-Oct)	7,757,176	$0.0079218	$61,451	(7,757,176)	-$61,451	-				
170	Delivery Charge - Current	1,494,024	$0.0080485	$12,025	7,960,402	$64,069	9,454,426	$76,094	$0.008049	$76,094	
171	Total Margin			$123,275		$2,618		$125,894		$125,894	$0
172	Non-Gas Revenue										
173	Adjustment			$155							
174	Franchise Tax			$5,060							
175	Gross Revenue Fee			$3,224							
176	Previous Month CA1501A -			-$131,559		$131,559					
177	Current Month CA1501A +			$130,934		-$130,934					
178	Total Non-Gas Revenue			$7,814		$625					
179	**Total Rate Schedule 904 Revenue**			$131,089		$3,244					
180	**<u>Rate Schedule 905 - Interruptible Transportation</u>**										
181	Dispatch Service Charge	12	$500.00	$6,000	-	$0	12	$6,000	$500.00	$6,000	

Cascade Natural Gas Corporation
Revenue Proof

		Current			Future Test Year Adjustments		Pro Forma		Proposed		
Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)=(C)*(E)	(G)=(B)+(E)	(H)=(C)*(G)	(I)	(J)=(G)*(I)	(K)=(J)-(H)
182	Contract Demand Charge	480,000	$0.0437500	$21,000	-	$0	480,000	$21,000	$0.043750	$21,000	
183	Delivery Charge (Jan-Oct)	5,658,261	$0.0110874	$62,735	(5,658,261)	-$62,735	-				
184	Delivery Charge - Current	1,253,517	$0.0112648	$14,121	7,438,744	$83,796	8,692,261	$97,917	$0.011265	$97,917	
185	Total Margin			$103,856		$21,061		$124,917		$124,917	$0
186	Non-Gas Revenue										
187	Adjustment			$177							
188	Franchise Tax			$0							
189	Gross Revenue Fee			$2,720							
190	Previous Month CA1501A -			-$106,576		$106,576					
191	Current Month CA1501A +			$106,868		-$106,868					
192	Total Non-Gas Revenue			$3,189		-$292					
193	**Total Rate Schedule 905 Revenue**			$107,045		$20,769					
194	**Total Cascade Margin**			$34,950,506				$31,989,470		$34,300,010	$2,310,540
195	**Total Cascade Revenue**			$64,010,077		$1,152,830					
196	**Miscellaneous Service Revenues**			$182,797							
197	**Rent From Gas Property**			$12,000							
198	**Interdepartmental Rents**			$25,558							
199	**Other Gas Revenue**			$44,349							
200	**TOTAL OPERATING REVENUE**			$64,274,782							

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 347

Cascade Natural Gas Corporation

Direct Testimony of Pamela J. Archer

EXHIBIT 500

May 31, 2018

EXHIBIT 500 – DIRECT TESTIMONY

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address

A. My name is Pamela J. Archer. My business address is 8113 W. Grandridge Boulevard, Kennewick, Washington 99336-7166. My email address is pamela.archer@cngc.com.

Q. By whom are you employed and in what capacity?

A. I am employed by Cascade Natural Gas Corporation (Cascade or Company) as the Supervisor, Regulatory Analysis.

Q. How long have you been employed by Cascade?

A. I have been with the Company since September 2010.

Q. What are your educational and professional qualifications?

A. I am a 1992 graduate of The Ohio State University with a B.S. in Chemical Engineering. In 1996, I graduated from Ashland University with a Master of Business Administration Degree. Prior to joining Cascade, I was employed as an Energy Specialist at the Office of the Ohio Consumers' Counsel for fifteen years. I have received additional training at the Annual Regulatory Studies Program sponsored by the National Association of Regulatory Utility Commissioners (NARUC) at Michigan State University in 1992 as well as at multiple NARUC sponsored events. I have also taken post-graduate courses in Managerial Accounting, Corporate Finance, and Business Law at The Ohio State University.

Q. Have you testified before the Public Utility Commission of Oregon (Commission) before?

A. Yes. I have also testified before the Commission in Cascade's most two recent Oregon general rate case, Docket Nos. UG 287 and UG 305.

//

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony in this docket?

A. In my testimony, I discuss the following three types of tariff changes made in this rate case:

1. Tariff revisions;
2. Changes in rates for gas service; and
3. Increases to two Miscellaneous Charges.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, I am sponsoring the following two exhibits which are explained in my testimony:

Exhibit No. CNGC/501 Proposed Tariff Sheets
Exhibit No. CNGC/502 Redlined Tariff Sheets

III. PROPOSED TARIFF CHANGES

Q. Is the Company proposing changes to its Tariff P.U.C. OR. No. 10?

A. Yes. This rate case filing includes the following revisions to its Tariff P.U.C. OR No. 10 (Tariff):

Sixth Revision of Sheet No. iii
Second Revision of Sheet No. 2.1
First Revision of Sheet No. 10.2
Second Revision of Sheet No. 17.1
Fifth Revision of Sheet No. 101.1
Second Revision of Sheet No. 104.1
First Revision of Sheet No. 105.1
Third Revision of Sheet No. 111.1
Third Revision of Sheet No. 163.1
Second Revision of Sheet No. 163.2
Second Revision of Sheet No. 163.3
First Revision of Sheet No. 163.4
First Revision of Sheet No. 163.5
First Revision of Sheet No. 163.6
Third Revision of Sheet No. 163.7
Second Revision of Sheet No. 163.8
First Revision of Sheet No. 163.9
Third Revision of Sheet No. 170.1
Second Revision of Sheet No. 170.2
Second Revision of Sheet No. 197.1
Third Revision of Sheet No. 200.1
First Revision of Sheet No. 800.2

The proposed revised tariff sheets are provided as Exhibit CNGC/501. Exhibit CNGC/502 provides the proposed changes in redline strike-out text.

Q. What is the nature of the proposed tariff changes?

A. The proposed tariff changes can be placed into the following three categories:

1. Tariff revisions;
2. Changes in rates for gas service; and
3. Increases to two Miscellaneous Charges.

Q. Please explain the changes to the Tariff characterized as tariff revisions.

A. The tariff revisions include edits made to correct or clarify text. Below is a list of tariff revisions made in this filing:

- Sheet iii – The title of Schedule 163 is revised consistent with other changes explained below. The index is revised accordingly.
- Sheet No. 2.1 – The definition for the "Residential" customer class is revised for improved clarity. The proposed language states that residential customers use gas for domestic purposes. The definition of a "Dwelling" is removed as a supporting term and is instead incorporated into the definition of Residential.
- Sheet No. 10.2 - Language is added to Rule 10, Main Extensions, that says the Company may allow the customers receiving service on Schedule 111, 163, or 170 to pay the non-economic portion of line extension costs through a flat monthly facility fee charged over an agreed-upon timeframe. This provision is consistent with the Company's current practice of offering payment arrangements for the non-economic portion of line extension costs for large volume customers, and is added for the purposes of consistency and transparency.
- Sheet No. 17.1 - Rule 17, Order of Priority for Gas Service, is revised to include clarifying text that states the Company will curtail customers in the same order of priority in a manner

that is appropriate for the situation. For instance, if the Company is curtailing Schedule 511 customers, it may be most efficient to curtail the largest Schedule 511 customers first.

- Sheet Nos. 163.1 through 163.9 – The tariff revisions to Schedule 163, General Distribution System Interruptible Transportation Service, include removing the Commodity Gas Charge which is old language that was inadvertently retained when the Company filed its new tariff book, P.U.C. 10 OR. No. 10 in Docket UG 305. The language that is removed refers to the upstream retail sale of gas to non-core customers, which was a competitive service that the Company has not offered in many years.

  Also, as discussed in the Direct Testimony of Ronald J. Amen (Exh. CNGC/600), a Contract Demand charge is added to Sheet No. 163.1. The Contract Demand defines the number of therms per day of distribution capacity that is reserved per day for that customer. Consistent with this change, the word, *Interruptible,* is removed from the title of this rate schedule, which is on the top of each sheet.

- Sheet No. 111.1, Sheet No. 170.1, Sheet No. 170.2 – The Company removes the language in Schedule 111, Large Volume General Service Rate and Schedule 170, Interruptible Service, providing that the customer will execute a service agreement that defines a minimum annual usage threshold that is negotiated between the Company and the customer. Currently, the customer is charged an annual deficiency bill for the difference between actual annual usage and the contractually agreed-upon minimum amount. The Company revises Schedules 111 and 170 to clarify that an annual deficiency bill may be issued if the customer does not consume the minimum threshold for service for each rate schedule, which is 50,000 therms per year for Schedule 111 and 180,000 therms per year for Schedule 170. The customer must meet the minimum usage threshold to receive service on either Schedule 111 or 170; if the customer does not meet the applicability threshold for annual usage, that customer is billed the difference between actual usage and the threshold, but no more.

- Sheet No. 800.2 - Schedule 800, Biomethane Receipt Services, is revised to include the Gross Revenue Fee that was inadvertently left out of the initial submission of this new service offering. The Gross Revenue Fee proposed for Schedule 800 collects the state utility tax and other governmental levies as a pass through, and is the same as the Gross Revenue Fee in Schedule 163, General Distribution System Interruptible Transportation Service. The Company currently has no customers on Schedule 800.

Q. Why is the Company revising its Tariff in a general rate case?

A. The Company filed to make most of the Tariff revisions in Advice No. O17-10-01, docketed as ADV 647. Commission Staff requested that the Company withdraw the filing because the items being clarified are related to customer charges and Staff therefore did not regard them as housekeeping in nature. Knowing the Company was filing a general rate case soon, Staff recommended the Company include the Tariff revisions in the rate case.

Q. Please explain the tariff changes characterized as changes to rates for gas service.

A. Below is a summary of the changes the Company is proposing to the rates for gas service:

- A Basic Monthly Service Charge is added to Schedule 111, Large Volume General Service and Schedule 170, Interruptible Service.
- The Basic Service Charge is increased for Schedules 101, General Residential Service; Schedule 104, General Commercial Service; Schedule 105, General Industrial Service; and Schedule 163, General Distribution System Interruptible Service.
- An additional volumetric rate block is added to Schedule 163, General Distribution System Interruptible Service.
- As mentioned above, a contract demand charge is added to Schedule 163, General Distribution System Interruptible Service.

- The Delivery Charge for each rate schedule for gas service is revised.
- Sheet No. 197.1 – Schedule 197, Environmental Remediation Cost Adjustment, is revised to include the updated rate as discussed in the Direct Testimony of Michael P. Parvinen (Exh. CNGC/200).

The proposed changes to the rates for gas service are revised as discussed in further detail in the Direct testimony of Ronald J. Amen, Exh. CNGC/600. The corresponding proposed changes to the tariff are submitted in CNGC/501. Redline changes are provided in CNGC/502.

Q. Please explain the changes to the Miscellaneous Charges.

A. The Company proposes an increase to two fees in Schedule 200, Various Miscellaneous Charges. The first increase is to the Returned Payment Charge, from $10 to $25; and the second increase is to the Field Visit Charge, from $10 to $20.

Q. Why is Cascade seeking to increase its Field Visit Charge and its Returned Payment Charge?

A. These two fees have not been updated since the 1980s.[1] The costs incurred to perform a field visit or to process a returned payment have increased since then, which means the gap between the cost incurred and the amount charged has widened. The Company proposes increasing these two fees so that the charges are better aligned with the costs charged by other utilities for the same or similar services.

Q. How does Cascade's Field Visit Charge and its Returned Payment Charge compare with other energy utilities' like charges?

A. Table 1 below compares the rates other energy utilities in Oregon charge for a field visit and a returned payment. Cascade's charges are the lowest. The increases to these charges

[1] It appears the fees may have changed sometime between 1972 and 1988. The Company's records are not complete; and therefore, Cascade cannot specify the exact date that these charges were last updated.

proposed in my testimony will bring Cascade's charges more in line with those that were found to be fair and reasonable for other utilities under the Commission's jurisdiction.

Table 1. Comparison of Oregon Energy Utilities' Returned Payment Fee and Field Visit Charge

Utility	Returned Payment Charge	Field Visit Charge
Portland General Electric	$25	$20
Avista	$25	n/a
PacifiCorp	$20	$20
Idaho Power	$20	$20
NW Natural	$15	$20
Cascade Natural Gas	$10	$10

Q. What impact would these proposed changes have on revenues?

A. These proposed changes to the Field Visit Charge and the Returned Payment Charge would result in an increase to revenues of about $24,714 per year. Please see Exhibit CNGC/304 and the corresponding workpaper for a more detailed explanation of the revenue impact of the proposed changes to the Miscellaneous Charges.

IV. CONCLUSION

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

PAMELA J.
ARCHER
Exhibit No. 501

Proposed Tariff Sheets

INDEX

RATE SCHEDULES (continued)

RATE ADJUSTMENTS

OTHER CHARGES

OPTIONAL SERVICES

RULE 2
DEFINITIONS

DEFINITIONS
When used in this Tariff the following terms shall have the meanings defined below:

1. Applicant - A person, firm, or corporation that (1) applies for service; (2) reapplies for service at a new or existing location after service has been disconnected; or (3) has not met the requirements for becoming a customer as established in Rule 3.

2. BTU - British Thermal Unit

3. British Thermal Unit - The standard unit for measuring a quantity of thermal energy. One BTU equals the amount of thermal energy required to raise the temperature of one pound of water one-degree Fahrenheit and is exactly defined as equal to 1,055.05585262 joules. 100,000 BTUs is equivalent to one therm.

4. Commission - The Public Utility Commission of Oregon or otherwise referred to as OPUC.

5. Company - Cascade Natural Gas Corporation (Cascade) or its assigned agents acting through its duly authorized officers or employees within the scope of their respective duties.

6. Core Customer – A core customer is one for whom the Company purchases and delivers natural gas.

7. Customer - Any person, firm, or corporation that has:
   a. Applied for, been accepted, and is currently receiving gas and, or distribution service from the Company under these Rules and Regulations at one location under one rate classification contract, or
   b. Received gas or distribution service from the Company, and voluntarily terminated service within the past twenty days.

8. Curtailment **-** An event when the Company must interrupt service to customers in accordance with Rule 17. The amount of service reduction required and the length of time for any curtailment event is dependent upon the severity and geographical scope of the circumstances requiring the curtailment.

9. Customer Classifications:
   Residential - Customers that use Natural Gas for domestic purposes. The residential customer class includes service to single-family dwellings, separately metered apartments, condominiums or townhouses, and centrally metered multiple dwellings or apartments but does not include spaces for transient occupancy such as hotels and motels. (C)
   (C)

.

(continued)

RULE 10
MAIN INSTALLATIONS

MAIN EXTENSIONS (continued)

2. An additional amount determined at the end of the fifth year as follows:

(a)	Actual therms billed for the five-year period to the customer or customers upon which the advance was predicated	XXXX
(b)	Less estimated annual therms used in calculating the advance times five (5)	XXXX
(c)	Difference	XXXX

If (c) is a positive number, an additional refund shall be calculated by multiplying (c) by the gross margin per therm employed in determining the original free footage allowance.

3. Refund or refunds in total shall not exceed the total amount advanced. If the total advanced has not been fully refunded within five (5) years of the date the advance was received by the Company, any remaining unrefunded amount shall become the property of the Company. (T)

4. When two (2) or more parties make a joint advance on the same extension, refund amounts which become payable will be allocated to such parties in proportion to the amounts advanced by the party. (T)

The Company may allow customers receiving service on Schedule 111, 163, or 170 the opportunity to pay the non-economic portion of main extension costs over time through a facility charge that will be billed as a flat monthly rate over an agreed upon period of time. In such instances, the Company may require the customer to provide an irrevocable letter of credit in the amount not to exceed the non-economic portion of the main extension costs and for the timeframe not to exceed the payback period. (N)

All facilities installed under this rule shall be the property of and under the control of the Company at all times and may be extended to serve other customers at the option of the Company.

RULE 17
ORDER OF PRIORITY FOR GAS SERVICE

GENERAL
The Company will exercise reasonable diligence to supply and deliver continuous natural gas service to all customers receiving firm service, as defined in Rule 2.

Should the Company's supply of gas or capacity be insufficient at any time or any location, for reasons other than force majeure (as defined in Company's Rule 16) to meet the full requirements of all customers, the Company will curtail service to customers in the inverse order of order of priority listed hereinafter. Such curtailment, when required, will be imposed to protect continuity of service first, to firm service customers, and more generally, to customers having a higher service priority.

ORDER OF PRIORITY
1. Residential customers (Schedule 101)
2. Commercial customers (Schedule 104)
3. General Industrial customers (Schedule 105)
4. Large Volume customers (Schedule 111)
5. Special contracts customers (Schedule 201)
6. General distribution system transportation service customers (Schedule 163)
7. Interruptible natural gas service customers (Schedule 170)

ADMINISTRATION OF CURTAILMENT
When the Company requires a curtailment due to either gas supply or capacity failures, the curtailment shall be imposed first on customers in the lowest order of priority category at the rate of 100% of each customer's requirements (excepting minor requirements for essential services as approved by Company) on a customer-by-customer basis and will then proceed to customers in the next lowest order of priority category, and so on, until sufficient volumes have been curtailed to bring remaining requirements into balance with available system supply. The Company will curtail customers within the same order of priority in the manner it deems is most appropriate for the situation; for instance, the Company may choose to curtail the highest volume customers before curtailing lower volume gas users within the same customer class. (N) (N)

The Company shall have the right to inspect the customer's gas consuming facilities and to review operating schedules for such facilities to determine customer's requirements and proper position in the order of priority. If the customer refuses such inspection, the customer will be assigned the lowest priority consistent with otherwise verifiable information.

Customer classifications referenced in the order of priority are defined in Company's Rule 2.

(continued)

SCHEDULE 101
GENERAL RESIDENTIAL SERVICE RATE

APPLICABILITY
This schedule is available to residential customers.

RATE

Basic Service Charge		$5.00	per month	(I)
Delivery Charge		$0.38815	per therm	(I)
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm	
Schedule 191	Temporary Gas Cost Rate	($0.019500)	per therm	
Schedule 192	Intervenor Funding	$0.001120	per therm	
Schedule 193	Conservation Alliance Plan	($0.065750)	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Cost	$0.000303	per therm	(R)
	Total	$0.710923	per therm	(I)

MINIMUM CHARGE (I)
Basic Service Charge $5.00

TERMS OF PAYMENT
Each monthly bill shall be due and payable within fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 104
GENERAL COMMERCIAL SERVICE RATE

APPLICABILITY
This schedule is available to commercial customers.

RATE

Basic Service Charge		$10.00	per month	(I)
Delivery Charge		$0.23878	per therm	(R)
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm	
Schedule 191	Temporary Gas Cost Rate	($0.019500)	per therm	
Schedule 192	Intervenor Funding	$0.000000	per therm	
Schedule 193	Conservation Alliance Plan	($0.065750)	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Cost	$0.000303	per therm	(R)
	Total	$0.560433	per therm	(R)

MINIMUM CHARGE (I)
Basic Service Charge $10.00

TERMS OF PAYMENT
Each monthly bill shall be due and payable within fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 105
GENERAL INDUSTRIAL SERVICE RATE

APPLICABILITY
This schedule is available to industrial customers.

RATE

Basic Service Charge		$30.00	per month	(I)
Delivery Charge		$0.23670	per therm	(I)
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm	
Schedule 191	Temporary Gas Cost Rate	($0.019500)	per therm	
Schedule 192	Intervenor Funding	$0.000730	per therm	
Schedule 193	Conservation Alliance Plan	$0.000000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Cost	$0.000303	per therm	(R)
	Total	$0.624833	per therm	(I)

MINIMUM CHARGE (I)
Basic Service Charge $30.00

TERMS OF PAYMENT
Each monthly bill shall be due and payable within fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 111
LARGE VOLUME GENERAL SERVICE RATE

APPLICABILITY
Service under this schedule shall be for natural gas supplied for all purposes to customers having an annual fuel requirement of not less than 50,000 therms and where the customer's major fuel requirement is for process use.

RATE

Basic Service Charge		$125.00	per month	(N)
Delivery Charge		$0.14936	per therm	(R)
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm	
Schedule 191	Temporary Gas Cost Rate	($0.019500)	per therm	
Schedule 192	Intervenor Funding	$0.000730	per therm	
Schedule 193	Conservation Alliance Plan	$0.000000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Cost	$0.000303	per therm	(R)
	Total	$0.537493	per therm	(R)

MINIMUM CHARGE
Basic Service Charge $125.00 (N)
(N)

SERVICE AGREEMENT
Customers receiving service under this rate schedule shall execute a service agreement for a minimum period of twelve consecutive months' use. The service agreement term shall be for a period not less than one year and the termination date of the service agreement in any year shall be September 30th. (D)

ANNUAL DEFICIENCY BILL
In the event the customer purchases less than the Annual Minimum Quantity of 50,000 therms as stated in the service agreement, the customer shall be charged an Annual Deficiency Bill. The Annual Deficiency Bill shall be calculated as the difference between the Annual Minimum Quantity and the actual purchase of transport therms times the difference between the per therm rates effective in this schedule and any modifying schedules less WACOG. (C) (T) (T)

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

PURPOSE
This schedule provides interruptible transportation service on the Company's distribution system of customer- supplied natural gas. Service under this schedule is subject to entitlement and curtailment.

APPLICABILTY
To be served on this schedule, the customer must have a service agreement with the Company. The customer must also have secured the purchase and delivery of gas supplies, which may include purchases from a third-party agent authorized by the customer served on this schedule. Such agent, otherwise known as a marketer or supplier and hereafter referred to as supplier, nominates and transports natural gas to the Company's system on a Customer's behalf in the manner established herein.

RATE
A. **Basic Service Charge** $625.00 per month (I)

B. **Contract Demand (CD) Charge** $0.10 per CD therm per day (N)
Contract Demand is the number of therms per day of distribution capacity the customer reserves on the Company's distribution system for delivery of the customer-supplied natural gas. The Company will determine each customer's CD which will be stated in the service agreement. Each monthly bill will include a charge that will be no less than the CD times the CD charge. The customer may be forced to curtail more gas than its CD rate if a curtailment per Rule 17 or entitlement as defined in this schedule is necessary, or Force Majeure circumstances per Rule 15 are experienced. (N)

C. **Distribution Charge** for All Therms Delivered Per Month (T)

		Base Rate	Sch. 192	Sch. 196	Sch 197	Billing Rate	
First	10,000	$0.137520	$0.000730	$0.00000	$0.000303	$0.138553	per therm
Next	10,000	$0.124060	$0.000730	$0.00000	$0.000303	$0.125093	per therm
Next	30,000	$0.116560	$0.000730	$0.00000	$0.000303	$0.117593	per therm
Next	50,000	$0.071590	$0.000730	$0.00000	$0.000303	$0.072623	per therm
Next	400,000	$0.036310	$0.000730	$0.00000	$0.000303	$0.037343	per therm
Next	500,000	$0.019460	$0.000730	$0.00000	$0.000303	$0.020493	per therm
Over	1,000,000	$0.001423	$0.000730	$0.00000	$0.000303	$0.002456	per therm

(I) (I) (N)

D. **Commodity Gas Supply Charge** (T)
The Company will pass through to the customer served on this schedule all costs, if any, incurred for securing the necessary supply at the city gate excluding pipeline transportation charges.

(M)

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

E. **Gross Revenue Fee** (M)(T)
The total of all charges invoiced by Company shall be subject to a Gross Revenue Fee of 2.91%. The Gross Revenue Fee is a reimbursement charge to cover state utility tax and other governmental levies imposed upon the Company, as those fees and levies may be in effect from time to time. (T) (T) (M)

WAIVER OF FIRM GAS SUPPLY
Customers electing to provide their own gas supplies under this schedule in lieu of firm service waive protection from supply-failure curtailment of all their requirements. The Company has no obligation to purchase or reserve gas supply or interstate pipeline capacity for customers electing to provide their own gas supplies and/or their own interstate pipeline capacity.

Customers electing to provide their own gas supplies under this schedule in lieu of firm system supply waive any right to automatically purchase firm supplies at some future date

Service under this Schedule is subject to curtailment per Rule 17 or entitlement as defined in this schedule.

SERVICE AGREEMENT
Service under this schedule requires an executed service agreement between the Company and the customer. The service agreement shall define the Contract Demand. The service agreement term shall be for a period not less than the period covered under the customer's gas purchase contract with the customer's supplier. However, in no event shall the service agreement be for less than one year and the termination date of the service agreement in any year shall be September 30th. (C)

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

GAS SUPPLY
The customer served under this rate schedule must secure the purchase and delivery of gas supplies from a supplier.

SUPPLIER AND RELATED RESPONSIBILITIES
The customer must provide in writing to the Company the name and telephone number of its supplier who will have authority to nominate natural gas supplies on Company's distribution system for delivery on customer's behalf.

The supplier is the customer's designated representative who satisfies or undertakes the following transportation duties and obligations:

1. Submitting and/or receiving notices on behalf of a customer;
2. Making nominations on behalf of a customer. A nomination is a request to have a physical quantity of customer-owned gas delivered to a specific Company receipt point(s) for a specific gas day. Nominations are not considered final until confirmed by the Pipeline;
3. Arranging for trades of imbalances on behalf of a customer as permitted under the terms and conditions herein established. An imbalance is the difference between a confirmed nominations and the volume of gas actually used by or delivered to a customer served under this schedule for a defined period of time;
    a. A positive imbalance exists when the volume of transportation gas confirmed for a Customer's account is greater than the volume of gas used.
    b. A negative imbalance exists when the volume of Transportation gas confirmed for Customer's account is less than the volume of gas used; and,
4. Performing operational and transportation-related administrative tasks on behalf of a customer as the Company permits.

Unless the Company and customer otherwise agree, a customer shall select one supplier for each account at any given time.

Under no circumstances will the appointment of a supplier relieve a customer of the responsibility to make full and timely payments to the Company for all distribution service.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

SUPPLIER AND RELATED RESPONSIBILITIES (continued)
Under no circumstances will the appointment of a supplier relieve a customer of the responsibility to make full and timely payments to the Company for all distribution service.

Each supplier must meet any applicable registration and licensing requirements established by law or regulation. The Company shall have the right to establish reasonable financial and non- discriminatory credit standards for qualifying suppliers. Accordingly, in order to serve customers on the Company's system, the supplier shall provide the Company, on a confidential basis, with audited balance sheet and other financial statements, such as annual reports to shareholders and 10-K reports, for the previous three years, as well as two trade and two banking references. To the extent that such annual reports and 10-K reports are not publicly available, the supplier shall provide the Company with a comparable list of all corporate affiliates, parent companies and subsidiaries. The supplier shall also provide its most recent reports from credit reporting and bond rating agencies. The supplier shall be subject to a credit investigation by the Company. The Company will review the supplier's financial position periodically.

If the supplier fails to comply with or perform any of the obligations on its part established in this schedule including but not limited to failure to deliver gas, pay bills in a timely manner, execute an upstream transportation capacity assignment, or, in general, act in good faith on behalf of the customer, the Company maintains the right to terminate the supplier's eligibility to act as a supplier on the Company's system.

NOMINATIONS
A customer served on this schedule is required to report estimated gas supply requirements for the upcoming month at least by the 15th day of the current month, in order to provide the Company with information for gas supply acquisition purposes. Such estimate shall include any scheduled down time or increased production time.

A customer served on this schedule is required to report estimated gas requirements daily to the Company's gas scheduling department at least thirty-two hours prior to the beginning of each gas day, as defined in Rule 2, unless other arrangements are agreed upon in writing with the Company. Such estimated requirement shall be considered as customer's daily nomination. Such daily nomination will separately identify gas quantities, if any, pursuant to obligations established below, as well as the customer's current estimated gas requirement at customer's facility (excluding gas provided to the transporting pipeline for compression and line loss "fuel"). In the event Company's supplier determines that the customer's actual consumption is out of balance with the customer's nomination, the supplier shall inform the customer of the adjustments necessary to get back in balance. Changes to a customer's daily nomination are allowed during the gas day provided the change is communicated to the Company one hour prior to the upstream pipeline's re-nomination deadline.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

NOMINATIONS (continued)
The Company shall have the right to adjust a customer's daily nominations when, in the Company's sole judgment, such action is necessary to bring into balance its system nominations as a receiving party on a pipeline system, or otherwise to maintain operational control or maintain the integrity of the Company's distribution system. The Company accepts customer purchased gas at the receipt point subject to customer's warranty that at the time of the Company's receipt, customer has good title to all gas received, free and clear from all liens, encumbrances and claims. Customer shall indemnify and hold Company harmless should a third party make any claims regarding customer's title to gas transported under this schedule. The supplier shall warrant that it has or will have entered into the necessary arrangements for the purchase of gas supplies which it desires the Company to transport to its customers, and that it has or will have entered into the necessary upstream transportation arrangements for the delivery of these gas supplies to the designated receipt point. The supplier shall warrant to the Company that it has good title to or lawful possession of all gas delivered to the Company at the designated receipt point on behalf of the supplier or the supplier's customers. The supplier shall indemnify the Company and hold it harmless from all suits, actions, debts, accounts, damage, costs, losses, taxes, and expenses arising from or out of any adverse legal claims of third parties to or against said gas supply.

The supplier shall be responsible for making all necessary arrangements and securing all required regulatory or governmental approvals, certificates or permits to enable gas to be delivered to the Company's system.

The Customer shall be deemed to be in control and possession of the customer purchased gas until the Company has accepted it at the receipt point. The Company shall be deemed to be in control or possession of the customer purchased gas until the equivalent therms are delivered to the customer at the delivery point.

Failure to report estimated gas transportation requirements or comply with the written arrangements may be considered as a zero nomination for such gas day and may result in the penalties as described below.

A customer served on this schedule is required to notify the Company's gas scheduling department in advance of operating changes that would cause actual gas day consumption to vary either up or down by 10% or more from the reported gas day estimate. Such notification may mitigate potential penalties but will not indemnify customer from the responsibility for penalties described in the section below entitled Imbalances.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

IMBALANCES
Each customer served on this rate schedule shall be required to satisfy any monthly imbalance condition in the manner established below.

Upon notification by the Company that the customer has an imbalance greater than 5%, the customer will have 45 non-entitlement days to eliminate any such imbalance. The Company will bill the customer an imbalance penalty if the customer has not completely satisfied such imbalance condition. These non-entitlement penalties are $10.00 per MMBtu on the imbalance over -the allowed tolerance on a monthly basis.

Under any agency established hereunder, the Company shall rely upon information concerning the applicable customer's distribution service which is provided by the designated representative. All such information shall be deemed to have been provided by the customer. Similarly, any notice or other information provided by the Company to the supplier concerning the provision of distribution service to such customer shall be deemed to have been provided to the customer. The customer shall rely upon any information concerning distribution service that is provided to the supplier as if that information had been provided directly to the customer.

The Company shall determine the customer's daily gas supply entitlement based upon customer's gas requirements forecast and resulting nomination after Company has considered any curtailment of pipeline or distribution system capacity constraints and gas supply constraints. Such daily gas supply entitlements shall include the summation of all gas supply options and optional balancing service daily volumetric level contracted for by the customer. The Company shall notify the supplier and/or customer in the event that the gas supply entitlement is less than the customer's gas nomination(s).

Penalties from upstream pipeline transporter and/or other costs incurred by Company as a result of a nomination imbalance or an unauthorized overrun will be passed on directly to those customer(s) or groups of customers whose take levels contribute to the imposition of the penalty. Such penalty shall be allocated among such customers, including Company's system supply customers, in proportion to the nomination imbalance or unauthorized overrun associated with each customer or group of customers.

PRIORITY OF NOMINATED GAS
The Company shall designate the daily volume of gas delivered to the customer under this schedule in the following sequence as applicable, unless other sequencing has been agreed to in writing by the Company:

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

PRIORITY OF NOMINATED GAS (continued)

1) The volume of system supplies which are scheduled to be made a portion of customer's gas supply nomination, if any.
2) If customer is providing a portion of its gas supply requirement with customer-owned gas supplies, the volume of banked customer owned gas supplies, if any, shall be delivered prior to any other non-system supply.
3) The volume of spot market gas supply scheduled to be delivered, if any.

AUTOMATIC ASSIGNMENT OF GAS SUPPLY DURING A CURTAILMENT (T)
In the event of a curtailment, the Company may automatically take assignment of customer-owned gas supplies in order to protect the service to higher priority customers as defined in Rule 17, Order of Priority for Gas Service. If the Company takes assignment of the customer-owned gas, the Company will compensate the customer with a credit equal to the Gas Daily-midpoint price at the source of the supply for all volumes assigned plus a credit of $0.60 per therm on all but the first 5 percent of the customer's daily entitlement under this Schedule.

UNAUTHORIZED USE OF GAS DURING ENTITLEMENT PERIODS
The Company may declare an entitlement period on any day the Company, in its sole discretion, reasonably determines a critical operational condition warrants the need. During a curtailment or an entitlement period, the total physical quantity of gas taken by customers served under this rate schedule exceeds or is less than the total quantity of gas which the customer is entitled to take on such day, as defined below, then all gas taken in excess of such entitlement or not taken within said entitlement shall constitute unauthorized overrun or underrun volume. Each general system or customer-specific declared overrun entitlement period shall be specified as either an overrun or an underrun entitlement for customers such that only one penalty condition may exist at one time, whereas:

- **Underrun Entitlement** – A period of time in which delivered natural gas volumes to a transportation customer may not exceed the customer's confirmed nomination for that day.
- **Overrun Entitlement –** A period of time in which delivered natural gas volumes to a transportation customer must be equal to or more than that customer's confirmed nomination for that day.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

UNAUTHORIZED USE OF GAS DURING CUTRAILMENTS OR ENTITLEMENT PERIODS (continued)
Customers served under this schedule shall pay Company for all unauthorized overrun or underrun quantities that exceed the percentage specified by the Company in its declared entitlement. For a general system or customer-specific declared entitlement period, such percentage will be: (i) in the Company's sole discretion 3 percent, or, in the case of a declared overrun entitlement period announced on the day it is to be in effect, 5 percent for that day (Stage I), 8 percent (Stage II) or 13 percent (Stage III) of a customer's entitlement as set forth above.

A customer's usage of gas that exceeds the amount authorized by the Company during an entitlement period shall be considered an unauthorized overrun volume. The overrun charge that will be applied during any overrun entitlement period will equal the greater of $1.00 per therm or 150% of the highest midpoint price for the day at NW Wyoming Pool, NW south of Green River, Stanfield Oregon, NW Canadian Border (Sumas), Kern River Opal, or El Paso Bondad supply pricing points (as published in Gas Daily), converted from dollars per dekatherms to dollars per therm by dividing by ten. The overrun charge will be in addition to the incremental costs of any supplemental gas supplies the Company may have had to purchase to cover such unauthorized use, in addition to the regular charges incurred in the Rate section of this Schedule and any other charges incurred per the terms and conditions established in this Schedule. The payment of an overrun penalty shall not under any circumstances be considered as giving customer the right to take unauthorized overrun gas or to exclude any other remedies which may be available to the Company to prevent such overrun. The charge that will apply during any underrun entitlement period will be $1.00 per therm for any underrun imbalances.

NOTICE OF ENTITLEMENT
The Company shall give as much advance notice as possible for each entitlement. The Company's entitlement periods as well as restoration notices shall be given by telephonic communications, electronic communication, or personal contact by Company personnel to the customer's responsible representative. A notice of entitlement period will include the parameters for gas consumption during said entitlement period.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM TRANSPORTATION SERVICE (C)

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 170
INTERRUPTIBLE SERVICE

AVAILABILITY
This schedule is available for natural gas delivered for all purposes to customers having an annual fuel requirement of not less than 180,000 therms per year and where customer agrees to maintain standby fuel burning facilities and an adequate supply of standby fuel to replace the entire supply of natural gas delivered hereunder.

SERVICE
Service under this schedule shall be subject to curtailment by the Company when in the judgment of the Company such curtailment or interruption of service is necessary. Company shall not be liable for damages for or because of any curtailment of natural gas deliveries hereunder.

RATE

Basic Service Charge		$300.00	per month	(N)
Delivery Charge		$0.11714	per therm	(R)
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm	
Schedule 191	Gas Cost Rate Adjustment	($0.019500)	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.000730	per therm	
Schedule 193	Conservation Alliance Plan	$0.000000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Costs	$0.000303	per therm	(R)
All Therms per Month:	Total Per Therm Rate	$0.505273	per therm	(R)

MINIMUM CHARGE (N)
Basic Service Charge $300.00 (N)

TERMS OF PAYMENT
Each monthly bill shall be due and payable fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

SERVICE AGREEMENT
Service under this schedule requires an executed service agreement between the Company and the customer. The service agreement term shall be for a period not less than the period covered under the customer's gas purchase contract with the customer's supplier. However, in no event shall the service agreement be for less than one year and the termination date of the service agreement in any year shall be September 30th. (D)

(continued)

SCHEDULE 170
INTERRUPTIBLE SERVICE

ANNUAL DEFICIENCY BILL
In the event a customer purchases less than the Annual Minimum Quantity of 180,000 therms, as defined (C)
in the service agreement, the customer shall be charged an Annual Deficiency Bill. The Annual Deficiency (T)
Bill shall be calculated by multiplying the difference between the Annual Minimum Quantity and the actual
therms used times the commodity rate in this Rate Schedule 170 plus all applicable rate adjustments. If (T)
the Company curtailed or interrupted service, the Annual Minimum Quantity shall be reduced by a (T)
fraction, the numerator of which is the actual number of days or fraction thereof, service was curtailed
and the denominator of which is 365.

CURTAILMENT
Service under this schedule is subject to curtailment as established in Rule 17.

SPECIAL TERMS AND CONDITIONS
Service under this schedule shall be rendered through one or more meters at a single point of delivery and may at the Company's option be rendered in conjunction with firm service to said customer.

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 197
ENVIRONMENTAL REMEDIATION COST ADJUSTMENT

APPLICABLE
This adjustment is applicable to customers served on Schedule 101, 104, 105, 111, 163, 170, and 800.

PURPOSE
This schedule recovers environmental remediation costs for a former manufactured gas plant in Eugene, Oregon. The Company is authorized per Order No. 16-477 to recover $162,000 over a three-year period of time.

RATE
The following rate shall be applied to all applicable customers on an equal cents per therm basis:

$0.000303	per therm

(R)

LIMITATION
This temporary rate addition shall remain in effect until cancelled pursuant to order of the Oregon Public Utility Commission.

SPECIAL TERMS AND CONDITIONS
The rates named herein are subject to increases as set forth in Schedule No. 100 Municipal Exactions.

GENERAL TERMS
Service under this schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this schedule apply to service under this schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 200
VARIOUS MISCELLANEOUS CHARGES

APPLICABILITY
This schedule sets forth the provisions for various charges throughout these rules and regulations. The name and amount of the charges are listed below. The rules or rate schedules to which each charge applies are in parenthesis.

I. Customer Deposit Interest Rate (Rule 4) 1.4%

II. Reconnection Charge (Rule 5)
a. Standard, 8 a.m. and 5 p.m., Monday through Friday, excluding holidays $32.00
b. After Hours between 5 p.m. and 9 p.m., Monday through Friday $50.00
c. Same Business Day or on a Saturday, Sunday or holidays $100.00

A reconnection charge will be required for reestablishment of service at the same address for the same person taking service, if service was disconnected at the customer's request or if it was disconnected involuntarily for reasons other than for Company initiated safety or maintenance.

III. Deposit for Meter Test - (Rule 8) $50.00

IV. Field Visit Charge- (Rule 5) $20.00 (I)
A field visit charge may be assessed whenever Cascade visits a customer's address for the purpose of disconnecting service or reconnecting service and due to the customer's action is unable to complete the disconnection or reconnection.

V. Late Payment Charge – (Rule 5) 2%
A late payment charge at a rate determined by the Commission based upon a survey of prevailing market rates will be charged to the customer's current bill when the customer has a prior balance owing of $200 or more.

VI. Returned Payment Charge - (Rule 6) $25.00 (I)
A returned check fee of twenty-five dollars ($25.00) may apply for any payment returned unpaid. (T)

VI. Modifying an Existing Service Line – (Rule 9)
a. Time of Construction Crew
- An Individual Employee $70.00 per hour
- Construction Crew up to $220.00 per hour

b. Cost of Materials required to open and close service connection trench, including asphalt replacement, if any.

Schedule 800
Biomethane Receipt Services

MONTHLY CHARGES (continued)
A Gross Revenue Fee of 2.91% will be applied to the total of all charges for service under this schedule. (N)
The Gross Revenue Fee covers statue utility tax and other governmental levies in effect. (N)

In no instance will monthly charges be prorated. Monthly Charges represent costs incurred regardless of the Company's receipt of biomethane.

Failure to pay a monthly bill within 15 days of receipt of the bill may result in curtailment of receipt services and a Late Payment Charge as defined in Schedule 200 will be applied until full payment of any past due amount is received.

Upon termination of service under this Schedule, the Company may charge the Biomethane Producer for the removal and, or capping-off of Company-owned facilities.

The service charges herein are subject to increases as set forth in Schedule No. 31, Public Purpose (T)
Charge and Schedule No. 100, Municipal Exactions, as applicable. (T)

Service under this Schedule is not subject to Schedule 31, Public Purpose Charge. (T)

MONTHLY MINIMUM BILL:
The monthly minimum bill shall be $2,500.00.

SERVICES PROVIDED:
The Company will provide a qualifying Biomethane Producer with a Company-owned, operated, and maintained point of interconnection to enable receipt of qualifying biomethane into the Company's distribution system for the purpose of delivering the biomethane to an end-user who is located on the Company's distribution system.

PREREQUISITES TO BIOMETHANE RECEIPT SERVICES
Preceding the receipt of biomethane, service under this Schedule requires an Interconnection Capacity Study and an Interconnection Study; both of which are followed by the execution of the Biomethane Receipt Services Agreement.

1. Interconnection Capacity Study
   To initiate the review prior to receiving service on this Schedule, a Biomethane Producer must provide the Company a written request for an Interconnection Capacity Study. The written request must include the following information: a) the location of the facilities; b) the source of the biomethane; c) specifics on forecasted minimum and maximum biomethane deliveries; d) forecasted operating profile; e) service pressure requirements or limitations; f) if natural gas and or the biomethane will be consumed on the site; g) details on the expected end-user of the biomethane, including the name and address and, if applicable, the anticipated gas marketer; and h) any other information deemed necessary by the Company.

(continued)

CNGC/502
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

PAMELA J. ARCHER
Exhibit No. 502

Redlined Tariff Sheets

INDEX

RATE SCHEDULES (continued)

RATE ADJUSTMENTS

OTHER CHARGES

OPTIONAL SERVICES

RULE 2
DEFINITIONS

DEFINITIONS

When used in this Tariff the following terms shall have the meanings defined below:

1. Applicant - A person, firm, or corporation that (1) applies for service; (2) reapplies for service at a new or existing location after service has been disconnected; or (3) has not met the requirements for becoming a customer as established in Rule 3.

2. BTU - British Thermal Unit

3. British Thermal Unit - The standard unit for measuring a quantity of thermal energy. One BTU equals the amount of thermal energy required to raise the temperature of one pound of water one degree Fahrenheit and is exactly defined as equal to 1,055.05585262 joules. 100,000 BTUs is equivalent to one therm.

4. Commission - The Public Utility Commission of Oregon or otherwise referred to as OPUC.

5. Company - Cascade Natural Gas Corporation (Cascade) or its assigned agents acting through its duly authorized officers or employees within the scope of their respective duties.

6. Core Customer – A core customer is one for whom the Company purchases and delivers natural gas. ~~(N)~~

7. Customer - Any person, firm, or corporation that has: ~~(C)~~
   a. Applied for, been accepted, and is currently receiving gas and, or distribution service from the Company under these Rules and Regulations at one location under one rate classification contract, or
   b. Received gas or distribution service from the Company, and voluntarily terminated service within the past twenty days.

8. Curtailment - An event when the Company must interrupt service to customers in accordance with Rule 17. The amount of service reduction required and the length of time for any curtailment event is dependent upon the severity and geographical scope of the circumstances requiring the curtailment. ~~(C)~~ ~~(C)~~

9. Customer Classifications:
   Residential - Customers that use Natural Gas for domestic purposes. The residential customer class includes service to single-family dwellings, separately metered apartments, condominiums or townhouses, and centrally metered multiple dwellings or apartments but does not include spaces for transient occupancy such as hotels and motels. (C)

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~~Service to a single family dwelling, two family (duplex) dwelling or to an individual dwelling unit in a multiple family dwelling building for residential purposes including space heating, water heating, and cooking.~~

~~A.~~

1. ~~Dwelling - A building designed exclusively for housing that contains permanent facilities for sleeping, bathing, and cooking. A dwelling may be a one family home, a duplex, a multiplex, but not including hotel or motel units that have no permanent kitchens.~~

(continued)

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RULE 10
MAIN INSTALLATIONS

MAIN EXTENSIONS (continued)

2. An additional amount determined at the end of the fifth year as follows:

(a)	Actual therms billed for the five-year period to the customer or customers upon which the advance was predicated	XXXX
(b)	Less estimated annual therms used in calculating the advance times five (5)	XXXX
(c)	Difference	XXXX

If (c) is a positive number, an additional refund shall be calculated by multiplying (c) by the gross margin per therm employed in determining the original free footage allowance.

~~1.~~ 3. Refund or refunds in total shall not exceed the total amount advanced. If the total advanced has not been fully refunded within five (5) years of the date the advance was received by the Company, any remaining unrefunded amount shall become the property of the Company.

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4.~~3~~. When two (2) or more parties make a joint advance on the same extension, refund amounts which become payable will be allocated to such parties in proportion to the amounts advanced by the party.

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The Company may allow customers receiving service on Schedule 111, 163, or 170 the opportunity to pay the non-economic portion of main extension costs over time through a facility charge that will be a billed as a flat monthly rate over an agreed upon period of time. In such instances, the Company may require the customer to provide an irrevocable letter of credit in the amount not to exceed the non-economic portion of the main extension costs and for the timeframe not to exceed the payback period.

All facilities installed under this rule shall be the property of and under the control of the Company at all times and may be extended to serve other customers at the option of the Company.

RULE 17
ORDER OF PRIORITY FOR GAS SERVICE

GENERAL
The Company will exercise reasonable diligence to supply and deliver continuous natural gas service to all customers receiving firm service, as defined in Rule 2.

Should the Company's supply of gas or capacity be insufficient at any time or any location, for reasons other than force majeure (as defined in Company's Rule 16) to meet the full requirements of all customers, the Company will curtail service to customers in the inverse order of order of priority listed hereinafter. Such curtailment, when required, will be imposed to protect continuity of service first, to firm service customers, and more generally, to customers having a higher service priority.

ORDER OF PRIORITY
1. Residential customers (Schedule 101)
2. Commercial customers (Schedule 104)
3. General Industrial customers (Schedule 105)
4. Large Volume customers (Schedule 111)
5. Special contracts customers (Schedule 201)
6. General distribution system transportation service customers (Schedule 163)
7. Interruptible natural gas service customers (Schedule 170)

ADMINISTRATION OF CURTAILMENT
When the Company requires a curtailment due to either gas supply or capacity failures, the curtailment shall be imposed first on customers in the lowest order of priority category at the rate of 100% of each customer's requirements (excepting minor requirements for essential services as approved by Company) on a customer-by-customer basis and will then proceed to customers in the next lowest order of priority category, and so on, until sufficient volumes have been curtailed to bring remaining requirements into balance with available system supply. The Company will curtail customers within the same order of priority in the manner it deems is most appropriate for the situation; for instance, the Company may choose to curtail the highest volume customers before curtailing lower volume gas users within the same customer class. (N)
(N)

The Company shall have the right to inspect the customer's gas consuming facilities and to review operating schedules for such facilities to determine customer's requirements and proper position in the order of priority. If the customer refuses such inspection, the customer will be assigned the lowest priority consistent with otherwise verifiable information.

Customer classifications referenced in the order of priority are defined in Company's Rule 2.

(continued)

SCHEDULE 101
GENERAL RESIDENTIAL SERVICE RATE

APPLICABILITY
This schedule is available to residential customers.

RATE

Basic Service Charge		$45.00	per month
Delivery Charge		$0.~~36407~~38815	per therm
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm
Schedule 191	Temporary Gas Cost Rate	($0.019500)	per therm
Schedule 192	Intervenor Funding	$0.001120	per therm
Schedule 193	Conservation Alliance Plan	($0.065750)	per therm
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm
Schedule 197	Environmental Remediation Cost	$0.000~~514~~303	per therm
	Total	$0.710923~~687054~~	per therm

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MINIMUM CHARGE
Basic Service Charge $54.00

TERMS OF PAYMENT
Each monthly bill shall be due and payable within fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 104
GENERAL COMMERCIAL SERVICE RATE

APPLICABILITY
This schedule is available to commercial customers.

RATE

Basic Service Charge		$~~4~~10.00	per month
Delivery Charge		$0.~~262630~~23878	per therm
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm
Schedule 191	Temporary Gas Cost Rate	($0.019500)	per therm
Schedule 192	Intervenor Funding	$0.000000	per therm
Schedule 193	Conservation Alliance Plan	($0.065750)	per therm
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm
Schedule 197	Environmental Remediation Cost	$0.~~000514~~000303	per therm
	Total	$0.~~584494~~560433	per therm

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MINIMUM CHARGE
Basic Service Charge $10~~4~~.00

TERMS OF PAYMENT
Each monthly bill shall be due and payable within fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 105
GENERAL INDUSTRIAL SERVICE RATE

APPLICABILITY
This schedule is available to industrial customers.

RATE

Basic Service Charge		$30~~12~~.00	per month
Delivery Charge		$0.2367~~005570~~	per therm
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm
Schedule 191	Temporary Gas Cost Rate	($0.019500)	per therm
Schedule 192	Intervenor Funding	$0.000730	per therm
Schedule 193	Conservation Alliance Plan	$0.000000	per therm
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm
Schedule 197	Environmental Remediation Cost	$0.~~000514~~000303	per therm
	Total	$0.~~593914~~624833	per therm

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MINIMUM CHARGE
Basic Service Charge $30~~12~~.00

TERMS OF PAYMENT
Each monthly bill shall be due and payable within fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 111
LARGE VOLUME GENERAL SERVICE RATE

APPLICABILITY
Service under this schedule shall be for natural gas supplied for all purposes to customers having an annual fuel requirement of not less than 50,000 therms and where the customer's major fuel requirement is for process use.

RATE

Basic Service Charge		$125.00	per month
Delivery Charge		$0.~~16592~~14936	per therm
OTHER CHARGES:			
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm
Schedule 191	Temporary Gas Cost Rate	($0.019500)	per therm
Schedule 192	Intervenor Funding	$0.000730	per therm
Schedule 193	Conservation Alliance Plan	$0.000000	per therm
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm
Schedule 197	Environmental Remediation Cost	$0.~~000514~~000303	per therm
	Total	$0.~~554264~~537493	per therm

MINIMUM CHARGE
Basic Service Charge $125.00

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SERVICE AGREEMENT
Customers receiving service under this rate schedule shall execute a service agreement for a minimum period of twelve consecutive months' use. ~~The Annual Minimum Quantity is to be negotiated and included as part of the service agreement but in no case shall the Annual Minimum Quantity be less than 50,000 therms.~~ The service agreement term shall be for a period not less than one year and the termination date of the service agreement in any year shall be September 30th.

ANNUAL DEFICIENCY BILL
In the event the customer purchases less than the Annual Minimum Quantity of 50,000 therms as stated in the service agreement, the customer shall be charged an Annual Deficiency Bill. The Annual Deficiency Bill shall be calculated as the difference between the Annual Minimum Quantity ~~less~~ and the actual purchase ~~or~~ of transport therms times the difference between the per therm rates effective in this schedule and any modifying schedules less ~~the weighted average commodity cost of system supply gas as such costs are reflected in the Company's tariff~~WACOG.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE (C)

PURPOSE
This schedule provides interruptible transportation service on the Company's distribution system of customer- supplied natural gas. Service under this schedule is subject to entitlement and curtailment.

APPLICABILTY
To be served on this schedule, the customer must have a service agreement with the Company. The customer must also have secured the purchase and delivery of gas supplies, which may include purchases from a ~~third party~~third-party agent authorized by the customer served on this schedule. Such agent, otherwise known as a marketer or supplier and hereafter referred to as supplier, nominates and transports natural gas to the Company's system on a Customer's behalf in the manner established herein.

RATE
A. **Basic Service Charge** $625~~500~~.00 per month (~~C~~I)

B. **Contract Demand (CD) Charge** $0.10 per CD therm per day
Contract Demand is the number of therms per day of distribution capacity the customer reserves on the Company's distribution system for delivery of the customer-supplied natural gas. The Company will determine each customer's CD which will be stated in the service agreement. Each monthly bill will include a charge that will be no less than the CD times the CD charge. The customer may be forced to curtail more gas than its CD rate if a curtailment per Rule 17 or entitlement as defined in this schedule is necessary, or Force Majeure circumstances per Rule 15 are experienced. (N)

~~B~~C. **Distribution Charge** for All Therms Delivered Per Month (T)

		Base Rate	Sch. 192	Sch. 196	Sch 197	Billing Rate	
First	10,000	$0.137520 ~~$0.12402~~	$0.000730	$0.00000	$0.~~000514~~ 000303	$.138553~~0.12 5264~~	per therm
Next	10,000	$0.124060 ~~$0.11188~~	$0.000730	$0.00000	$0.000303 ~~514~~	~~$0.~~125093~~113 124~~	per therm
Next	30,000	$0.116560 ~~$0.10512~~	$0.000730	$0.00000	$0.000303 ~~514~~	~~$0.~~117593~~106 364~~	per therm
Next	50,000	$0.071590 ~~$0.06456~~	$0.000730	$0.00000	$0.000303 ~~514~~	~~$0.0~~07262~~365 804~~	per therm
Next	400,000	$0.036310 ~~$0.03275~~	$0.000730	$0.00000	$0.000303 ~~514~~	~~$0.~~037343~~033 994~~	per therm
~~Over~~ Next	500,000	$0.019460 ~~$0.01755~~	$0.000730	$0.00000	$0.000303 ~~514~~	~~$0.~~020493~~018 794~~	per therm
Over	1,000,000	$0.001423	$0.000730	$0.00000	$0.000303 ~~514~~	.002456	per therm

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~~C~~D. **Commodity Gas Supply Charge**
The Company will pass through to the customer served on this schedule all costs, if any, incurred for securing the necessary supply at the city gate excluding pipeline transportation charges.

~~D. **Gross Revenue Fee**~~ (D)
~~The total of all charges invoiced by Company shall be subject to a Gross Revenue Fee reimbursement charge to cover state utility tax and other governmental levies imposed upon the Company, as those fees and levies may be in effect from time to time.~~ (D)

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(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE (C)

E. **Gross Revenue Fee** (N)
The total of all charges invoiced by Company shall be subject to a Gross Revenue Fee of 2.91%. The Gross Revenue Fee is a reimbursement charge to cover state utility tax and other governmental levies imposed upon the Company, as those fees and levies may be in effect from time to time. (N)

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WAIVER OF FIRM GAS SUPPLY
Customers electing to provide their own gas supplies under this schedule in lieu of firm service waive protection from supply-failure curtailment of all their requirements. The Company has no obligation to purchase or reserve gas supply or interstate pipeline capacity for customers electing to provide their own gas supplies and/or their own interstate pipeline capacity.

Customers electing to provide their own gas supplies under this schedule in lieu of firm system supply waive any right to automatically purchase firm supplies at some future date

Service under this Schedule is subject to curtailment per Rule 17 or entitlement as defined in this schedule.

SERVICE AGREEMENT
Service under this schedule requires an executed service agreement between the Company and the customer. The service agreement shall define the ~~annual minimum quantity of gas to be delivered~~Contract Demand. The service agreement term shall be for a period not less than the period covered under the customer's gas purchase contract with the customer's supplier. However, in no event shall the service agreement be for less than one year and the termination date of the service agreement in any year shall be September 30th. (C)

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE (C)

GAS SUPPLY
The customer served under this rate schedule must secure the purchase and delivery of gas supplies from a supplier.

SUPPLIER AND RELATED RESPONSIBILITIES
The customer must provide in writing to the Company the name and telephone number of its supplier who will have authority to nominate natural gas supplies on Company's distribution system for delivery on customer's behalf.

The supplier is the customer's designated representative who satisfies or undertakes the following transportation duties and obligations:

1. Submitting and/or receiving notices on behalf of a customer;
2. Making nominations on behalf of a customer. A nomination is a request to have a physical quantity of customer-owned gas delivered to a specific Company receipt point(s) for a specific gas day. Nominations are not considered final until confirmed by the Pipeline;
3. Arranging for trades of imbalances on behalf of a customer as permitted under the terms and conditions herein established. An imbalance is the difference between a confirmed nominations and the volume of gas actually used by or delivered to a customer served under this schedule for a defined period of time;
    a. A positive imbalance exists when the volume of transportation gas confirmed for a Customer's account is greater than the volume of gas used.
    b. A negative imbalance exists when the volume of Transportation gas confirmed for Customer's account is less than the volume of gas used; and,
4. Performing operational and transportation-related administrative tasks on behalf of a customer as the Company permits.

Unless the Company and customer otherwise agree, a customer shall select one supplier for each account at any given time.

Under no circumstances will the appointment of a supplier relieve a customer of the responsibility to make full and timely payments to the Company for all distribution service. ~~(N)~~ ~~(N)~~

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SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE

(C)

SUPPLIER AND RELATED RESPONSIBILITIES (continued)
Under no circumstances will the appointment of a supplier relieve a customer of the responsibility to make full and timely payments to the Company for all distribution service.

Each supplier must meet any applicable registration and licensing requirements established by law or regulation. The Company shall have the right to establish reasonable financial and non- discriminatory credit standards for qualifying suppliers. Accordingly, in order to serve customers on the Company's system, the supplier shall provide the Company, on a confidential basis, with audited balance sheet and other financial statements, such as annual reports to shareholders and 10-K reports, for the previous three years, as well as two trade and two banking references. To the extent that such annual reports and 10-K reports are not publicly available, the supplier shall provide the Company with a comparable list of all corporate affiliates, parent companies and subsidiaries. The supplier shall also provide its most recent reports from credit reporting and bond rating agencies. The supplier shall be subject to a credit investigation by the Company. The Company will review the supplier's financial position periodically.

If the supplier fails to comply with or perform any of the obligations on its part established in this schedule including but not limited to failure to deliver gas, pay bills in a timely manner, execute an upstream transportation capacity assignment, or, in general, act in good faith on behalf of the customer, the Company maintains the right to terminate the supplier's eligibility to act as a supplier on the Company's system.

NOMINATIONS
A customer served on this schedule is required to report estimated gas supply requirements for the upcoming month at least by the 15th day of the current month, in order to provide the Company with information for gas supply acquisition purposes. Such estimate shall include any scheduled down time or increased production time.

A customer served on this schedule is required to report estimated gas requirements daily to the Company's gas scheduling department at least thirty-two hours prior to the beginning of each gas day, as defined in Rule 2, unless other arrangements are agreed upon in writing with the Company. Such estimated requirement shall be considered as customer's daily nomination. Such daily nomination will separately identify gas quantities, if any, pursuant to obligations established below, as well as the customer's current estimated gas requirement at customer's facility (excluding gas provided to the transporting pipeline for compression and line loss "fuel"). In the event Company's supplier determines that the customer's actual consumption is out of balance with the customer's nomination, the supplier shall inform the customer of the adjustments necessary to get back in balance. Changes to a customer's daily nomination are allowed during the gas day provided the change is communicated to the Company one hour prior to the upstream pipeline's re-nomination deadline.

(continued)

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SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE

(C)

NOMINATIONS (continued)
The Company shall have the right to adjust a customer's daily nominations when, in the Company's sole judgment, such action is necessary to bring into balance its system nominations as a receiving party on a pipeline system, or otherwise to maintain operational control or maintain the integrity of the Company's distribution system. The Company accepts customer purchased gas at the receipt point subject to customer's warranty that at the time of the Company's receipt, customer has good title to all gas received, free and clear from all liens, encumbrances and claims. Customer shall indemnify and hold Company harmless should a third party make any claims regarding customer's title to gas transported under this schedule. The supplier shall warrant that it has or will have entered into the necessary arrangements for the purchase of gas supplies which it desires the Company to transport to its customers, and that it has or will have entered into the necessary upstream transportation arrangements for the delivery of these gas supplies to the designated receipt point. The supplier shall warrant to the Company that it has good title to or lawful possession of all gas delivered to the Company at the designated receipt point on behalf of the supplier or the supplier's customers. The supplier shall indemnify the Company and hold it harmless from all suits, actions, debts, accounts, damage, costs, losses, taxes, and expenses arising from or out of any adverse legal claims of third parties to or against said gas supply.

The supplier shall be responsible for making all necessary arrangements and securing all required regulatory or governmental approvals, certificates or permits to enable gas to be delivered to the Company's system.

The Customer shall be deemed to be in control and possession of the customer purchased gas until the Company has accepted it at the receipt point. The Company shall be deemed to be in control or possession of the customer purchased gas until the equivalent therms are delivered to the customer at the delivery point.

Failure to report estimated gas transportation requirements or comply with the written arrangements may be considered as a zero nomination for such gas day and may result in the penalties as described below.

A customer served on this schedule is required to notify the Company's gas scheduling department in advance of operating changes that would cause actual gas day consumption to vary either up or down by 10% or more from the reported gas day estimate. Such notification may mitigate potential penalties but will not indemnify customer from the responsibility for penalties described in the section below entitled Imbalances.

(continued)

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SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE

(C)

IMBALANCES
Each customer served on this rate schedule shall be required to satisfy any monthly imbalance condition in the manner established below.

Upon notification by the Company that the customer has an imbalance greater than 5%, the customer will have 45 non-entitlement days to eliminate any such imbalance. The Company will bill the customer an imbalance penalty if the customer has not completely satisfied such imbalance condition. These non-entitlement penalties are $10.00 per MMBtu on the imbalance over -the allowed tolerance on a monthly basis.

Under any agency established hereunder, the Company shall rely upon information concerning the applicable customer's distribution service which is provided by the designated representative. All such information shall be deemed to have been provided by the customer. Similarly, any notice or other information provided by the Company to the supplier concerning the provision of distribution service to such customer shall be deemed to have been provided to the customer. The customer shall rely upon any information concerning distribution service that is provided to the supplier as if that information had been provided directly to the customer.

The Company shall determine the customer's daily gas supply entitlement based upon customer's gas requirements forecast and resulting nomination after Company has considered any curtailment of pipeline or distribution system capacity constraints and gas supply constraints. Such daily gas supply entitlements shall include the summation of all gas supply options and optional balancing service daily volumetric level contracted for by the customer. The Company shall notify the supplier and/or customer in the event that the gas supply entitlement is less than the customer's gas nomination(s).

Penalties from upstream pipeline transporter and/or other costs incurred by Company as a result of a nomination imbalance or an unauthorized overrun will be passed on directly to those customer(s) or groups of customers whose take levels contribute to the imposition of the penalty. Such penalty shall be allocated among such customers, including Company's system supply customers, in proportion to the nomination imbalance or unauthorized overrun associated with each customer or group of customers.

PRIORITY OF NOMINATED GAS
The Company shall designate the daily volume of gas delivered to the customer under this schedule in the following sequence as applicable, unless other sequencing has been agreed to in writing by the Company:

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE (C)

PRIORITY OF NOMINATED GAS (continued)

1) The volume of system supplies which are scheduled to be made a portion of customer's gas supply nomination, if any.
2) If customer is providing a portion of its gas supply requirement with customer-owned gas supplies, the volume of banked customer owned gas supplies, if any, shall be delivered prior to any other non-system supply.
3) The volume of spot market gas supply scheduled to be delivered, if any.

AUTOMATIC ASSIGNMENT ~~I~~OF GAS SUPPLY DURING A CURTAILMENT ~~(N)~~ (T)
In the event of a curtailment, the Company may automatically take assignment of customer-owned gas supplies in order to protect the service to higher priority customers as defined in Rule 17, Order of Priority for Gas Service. If the Company takes assignment of the customer-owned gas, the Company will compensate the customer with a credit equal to the Gas Daily-midpoint price at the source of the supply for all volumes assigned plus a credit of $0.60 per therm on all but the first 5 percent of the customer's daily entitlement under this Schedule. ~~(N)~~

UNAUTHORIZED USE OF GAS DURING ENTITLEMENT PERIODS
The Company may declare an entitlement period on any day the Company, in its sole discretion, reasonably determines a critical operational condition warrants the need. During a curtailment or an entitlement period, the total physical quantity of gas taken by customers served under this rate schedule exceeds or is less than the total quantity of gas which the customer is entitled to take on such day, as defined below, then all gas taken in excess of such entitlement or not taken within said entitlement shall constitute unauthorized overrun or underrun volume. Each general system or customer-specific declared overrun entitlement period shall be specified as either an overrun or an underrun entitlement for customers such that only one penalty condition may exist at one time, whereas:

- **Underrun Entitlement** – A period of time in which delivered natural gas volumes to a transportation customer may not exceed the customer's confirmed nomination for that day.
- **Overrun Entitlement –** A period of time in which delivered natural gas volumes to a transportation customer must be equal to or more than that customer's confirmed nomination for that day.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE (C)

UNAUTHORIZED USE OF GAS DURING CUTRAILMENTS OR ENTITLEMENT PERIODS (continued)
Customers served under this schedule shall pay Company for all unauthorized overrun or underrun quantities that exceed the percentage specified by the Company in its declared entitlement. For a general system or customer-specific declared entitlement period, such percentage will be: (i) in the Company's sole discretion 3 percent, or, in the case of a declared overrun entitlement period announced on the day it is to be in effect, 5 percent for that day (Stage I), 8 percent (Stage II) or 13 percent (Stage III) of a customer's entitlement as set forth above.

(~~D)~~
~~(C)~~

A customer's usage of gas that exceeds the amount authorized by the Company during an entitlement period shall be considered an unauthorized overrun volume. The overrun charge that will be applied during any overrun entitlement period will equal the greater of $1.00 per therm or 150% of the highest midpoint price for the day at NW Wyoming Pool, NW south of Green River, Stanfield Oregon, NW Canadian Border (Sumas), Kern River Opal, or El Paso Bondad supply pricing points (as published in Gas Daily), converted from dollars per dekatherms to dollars per therm by dividing by ten. The overrun charge will be in addition to the incremental costs of any supplemental gas supplies the Company may have had to purchase to cover such unauthorized use, in addition to the regular charges incurred in the Rate section of this Schedule and any other charges incurred per the terms and conditions established in this Schedule. The payment of an overrun penalty shall not under any circumstances be considered as giving customer the right to take unauthorized overrun gas or to exclude any other remedies which may be available to the Company to prevent such overrun. The charge that will apply during any underrun entitlement period will be $1.00 per therm for any underrun imbalances.

NOTICE OF ENTITLEMENT ~~(C)~~
The Company shall give as much advance notice as possible for each entitlement. The Company's entitlement periods as well as restoration notices shall be given by telephonic communications, electronic communication, or personal contact by Company personnel to the customer's responsible representative. A notice of entitlement period will include the parameters for gas consumption during said entitlement period. ~~(C)~~

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM ~~INTERRUPTIBLE~~ TRANSPORTATION SERVICE (C)

GENERAL TERMS
Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 170
INTERRUPTIBLE SERVICE

AVAILABILITY
This schedule is available for natural gas delivered for all purposes to customers having an annual fuel requirement of not less than 180,000 therms per year and where customer agrees to maintain standby fuel burning facilities and an adequate supply of standby fuel to replace the entire supply of natural gas delivered hereunder.

SERVICE
Service under this schedule shall be subject to curtailment by the Company when in the judgment of the Company such curtailment or interruption of service is necessary. Company shall not be liable for damages for or because of any curtailment of natural gas deliveries hereunder.

RATE

Basic Service Charge		$300.00	per month	
Delivery Charge		$0.~~12309~~11714	per therm	
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm	
Schedule 191	Gas Cost Rate Adjustment	($0.019500)	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.000730	per therm	
Schedule 193	Conservation Alliance Plan	$0.000000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Costs	$0.~~000514~~000303	per therm	(R)
All Therms per Month:	Total Per Therm Rate	$0.~~511434~~505273	per therm	(R)

MINIMUM CHARGE (N)
Basic Service Charge $300.00 (N)

TERMS OF PAYMENT
Each monthly bill shall be due and payable fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

SERVICE AGREEMENT
Service under this schedule requires an executed service agreement between the Company and the customer. ~~The service agreement shall define the annual minimum quantity of gas to be delivered.~~ The service agreement term shall be for a period not less than the period covered under the customer's gas purchase contract with the customer's supplier. However, in no event shall the service agreement be for less than one year and the termination date of the service agreement in any year shall be September 30th.

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SCHEDULE 170
INTERRUPTIBLE SERVICE

AVAILABILITY
This schedule is available for natural gas delivered for all purposes to customers having an annual fuel requirement of not less than 180,000 therms per year and where customer agrees to maintain standby fuel burning facilities and an adequate supply of standby fuel to replace the entire supply of natural gas delivered hereunder.

SERVICE
Service under this schedule shall be subject to curtailment by the Company when in the judgment of the Company such curtailment or interruption of service is necessary. Company shall not be liable for damages for or because of any curtailment of natural gas deliveries hereunder.

RATE

Basic Service Charge		$300.00	per month	
Delivery Charge		$0.~~12309~~11714	per therm	
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.406600	per therm	
Schedule 191	Gas Cost Rate Adjustment	($0.019500)	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.000730	per therm	
Schedule 193	Conservation Alliance Plan	$0.000000	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Costs	$0.000514	per therm	
All Therms per Month:	Total Per Therm Rate	$0.~~511434~~505484	per therm	(R)

MINIMUM CHARGE (N)
Basic Service Charge $300.00 (N)

TERMS OF PAYMENT
Each monthly bill shall be due and payable fifteen days from the date of rendition.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for Municipal Exactions.

SERVICE AGREEMENT
Service under this schedule requires an executed service agreement between the Company and the customer. ~~The service agreement shall define the annual minimum quantity of gas to be delivered.~~ The service agreement term shall be for a period not less than the period covered under the customer's gas purchase contract with the customer's supplier. However, in no event shall the service agreement be for less than one year and the termination date of the service agreement in any year shall be September 30th.

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SCHEDULE 170
INTERRUPTIBLE SERVICE

ANNUAL DEFICIENCY BILL

In the event a customer purchases less than the ~~annual~~ Annual ~~minimum~~ Minimum Q~~q~~uantity of 180,000 therms, as defined in the ~~contract~~service agreement, the customer shall be charged an Annual Deficiency Bill. The Annual Deficiency Bill shall be calculated by multiplying the difference between the Annual Minimum Quantity and ~~the~~ the actual therms ~~actually taken~~used ~~(Deficiency Therms)~~ times ~~the difference between~~ the commodity rate in this Rate Schedule 170~~, as modified by~~ plus all ~~any~~ applicable rate adjustments.~~, and the weighted average commodity cost of system supply gas as such costs are reflected in the Company's tariffs~~. If the Company curtailed or interrupted service, the Annual Minimum Quantity shall be reduced by a fraction, the numerator of which is the actual number of days or fraction thereof, service was curtailed and the denominator of which is 365. (C) (T) (T) (T)

CURTAILMENT

Service under this schedule is subject to curtailment as established in Rule 17.

SPECIAL TERMS AND CONDITIONS

Service under this schedule shall be rendered through one or more meters at a single point of delivery and may at the Company's option be rendered in conjunction with firm service to said customer.

GENERAL TERMS

Service under this rate schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this rate schedule apply to service under this rate schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 197
ENVIRONMENTAL REMEDIATION COST ADJUSTMENT

APPLICABLE
This adjustment is applicable to customers served on Schedule 101, 104, 105, 111, 163, 170, and 800. ~~(C)~~

PURPOSE
This schedule recovers environmental remediation costs for a former manufactured gas plant in Eugene, Oregon. The Company is authorized per Order No. 16-477 to recover $162,000 over a three-year period of time.

RATE
The following rate shall be applied to all applicable customers on an equal cents per therm basis:

$0.~~000514~~.000303	per therm

(R)

LIMITATION
This temporary rate addition shall remain in effect until cancelled pursuant to order of the Oregon Public Utility Commission.

SPECIAL TERMS AND CONDITIONS
The rates named herein are subject to increases as set forth in Schedule No. 100 Municipal Exactions.

GENERAL TERMS
Service under this schedule is governed by the terms of this schedule, the Rules contained in this Tariff, any other schedules that by their terms or by the terms of this schedule apply to service under this schedule, and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 200
VARIOUS MISCELLANEOUS CHARGES

APPLICABILITY

This schedule sets forth the provisions for various charges throughout these rules and regulations. The name and amount of the charges are listed below. The rules or rate schedules to which each charge applies are in parenthesis.

I.	Customer Deposit Interest Rate (Rule 4)	1.4%	
II.	Reconnection Charge (Rule 5)		
	a. Standard, 8 a.m. and 5 p.m., Monday through Friday, excluding holidays	$32.00	
	b. After Hours between 5 p.m. and 9 p.m., Monday through Friday	$50.00	
	c. Same Business Day or on a Saturday, Sunday or holidays	$100.00	

A reconnection charge will be required for reestablishment of service at the same address for the same person taking service, if service was disconnected at the customer's request or if it was disconnected involuntarily for reasons other than for Company initiated safety or maintenance.

III.	Deposit for Meter Test - (Rule 8)	$50.00	
IV.	Field Visit Charge- (Rule 5)	$2~~1~~0.00	(I)

A field visit charge may be assessed whenever Cascade visits a customer's address for the purpose of disconnecting service or reconnecting service and due to the customer's action is unable to complete the disconnection or reconnection.

V.	Late Payment Charge – (Rule 5)	2%	

A late payment charge at a rate determined by the Commission based upon a survey of prevailing market rates will be charged to the customer's current bill when the customer has a prior balance owing of $200 or more.

VI.	Returned Payment Charge - (Rule 6)	$25~~10~~.00	(I)

A returned check fee of ~~ten~~ twenty-five dollars ($~~10~~25.00) may apply for any payment returned unpaid. (T)

VI. Modifying an Existing Service Line – (Rule 9)

a. Time of Construction Crew
- An Individual Employee — $70.00 per hour
- Construction Crew — up to $220.00 per hour

b. Cost of Materials required to open and close service connection trench, including asphalt replacement, if any.

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Schedule 800
Biomethane Receipt Services

MONTHLY CHARGES (continued)
A Gross Revenue Fee of 2.91% will be applied to the total of all charges for service under this schedule. The Gross Revenue Fee covers statue utility tax and other governmental levies in effect. (N)

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In no instance will monthly charges be prorated. Monthly Charges represent costs incurred regardless of the Company's receipt of biomethane.

Failure to pay a monthly bill within 15 days of receipt of the bill may result in curtailment of receipt services and a Late Payment Charge as defined in Schedule 200 will be applied until full payment of any past due amount is received.

Upon termination of service under this Schedule, the Company may charge the Biomethane Producer for the removal and, or capping-off of Company-owned facilities.

The service charges herein are subject to increases as set forth in Schedule No. 31, Public Purpose~~s~~ ~~Funding~~ Charge and Schedule No. 100, Municipal Exactions, as applicable.

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Service under this Schedule is not subject to Schedule 31, Public Purpose~~s Funding c~~Charge. (T)

MONTHLY MINIMUM BILL:
The monthly minimum bill shall be $2,500.00.

SERVICES PROVIDED:
The Company will provide a qualifying Biomethane Producer with a Company-owned, operated, and maintained point of interconnection to enable receipt of qualifying biomethane into the Company's distribution system for the purpose of delivering the biomethane to an end-user who is located on the Company's distribution system.

PREREQUISITES TO BIOMETHANE RECEIPT SERVICES
Preceding the receipt of biomethane, service under this Schedule requires an Interconnection Capacity Study and an Interconnection Study; both of which are followed by the execution of the Biomethane Receipt Services Agreement.

1. Interconnection Capacity Study
   To initiate the review prior to receiving service on this Schedule, a Biomethane Producer must provide the Company a written request for an Interconnection Capacity Study. The written request must include the following information: a) the location of the facilities; b) the source of the biomethane; c) specifics on forecasted minimum and maximum biomethane deliveries; d) forecasted operating profile; e) service pressure requirements or limitations; f) if natural gas and or the biomethane will be consumed on the site; g) details on the expected end-user of the biomethane, including the name and address and, if applicable, the anticipated gas marketer; and h) any other information deemed necessary by the Company.

(continued)

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

Cascade Natural Gas Corporation

Direct Testimony of Ronald J. Amen

LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN EXHIBIT CNG/600

May 31, 2018

DIRECT TESTIMONY – LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN

Contents

Regulatory Affairs
Cascade Natural Gas Corporation
8113 W. Grandridge Blvd.
Kennewick, WA 99336

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

A. My name is Ronald J. Amen and my business address is 17806 NE 109th Court, Redmond, Washington 98052.

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

A. I am appearing on behalf of Cascade Natural Gas Corporation (Cascade or the Company).

Q. By whom are you employed and in what capacity?

A. I am employed by Black & Veatch Management Consulting LLC (Black & Veatch) as a Director and I am a member of the Advisory & Planning Practice within Black & Veatch.

Q. Please describe the firm of Black & Veatch.

A. Black & Veatch Corporation has provided comprehensive engineering and management services to utility, industrial, and governmental entities since 1915. Black & Veatch Management Consulting LLC, a subsidiary of Black & Veatch Corporation, delivers management consulting solutions in the energy and water sectors. Our services include broad-based strategic, regulatory, financial, and information systems consulting. In the energy sector, Black & Veatch Management Consulting delivers a variety of services for companies involved in the generation, transmission, and distribution of electricity and natural gas.

Black & Veatch has extensive experience in all aspects of the North American natural gas industry, including utility costing and pricing, gas supply and transportation planning, competitive market analysis, and regulatory practices and policies gained through

Regulatory Affairs
Cascade Natural Gas Corporation
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management and operating responsibilities at gas distribution, pipeline, and other energy-related companies, and through a wide variety of client assignments. Black & Veatch has assisted numerous gas distribution companies located in the U.S. and Canada.

Q. What has been the nature of your work in the utility consulting field?

A. I have over 39 years of experience in the utility industry, the last 20 years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before utility regulatory bodies and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Exhibit CNG/609.

Q. Have you previously testified before any utility regulatory bodies?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission (FERC) and numerous state and provincial regulatory commissions, including testimony before the Public Utility Commission of Oregon (OPUC or the Commission) in Docket UG 287 and UG 305.

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Q. Please summarize your testimony.

A. In my testimony I present Cascade's Long-Run Incremental Cost (LRIC) Study and discuss its results, and I present the various rate design proposals filed by Cascade in this proceeding.

My testimony consists of this introduction and summary section and the following additional sections:

- Theoretical Principles of Cost Allocation
- Cascade's LRIC Study
- Principles of Sound Rate Design
- Determination of Proposed Class Revenues
- Summary of Cascade's Rate Design Proposals
- Residential & Non-Residential Class Bill Impacts

Q. Please provide a list of exhibits supporting your testimony.

A. The following exhibits accompany my testimony.

- Exhibit CNG/601 Summary of LRIC
- Exhibit CNG/602 Functional Revenue Requirement
- Exhibit CNG/603 Incremental Plant Carrying Costs
- Exhibit CNG/6 04 Incremental O&M Costs
- Exhibit CNG/605 Summary of Revenue by Rate Class
- Exhibit CNG/606 Analysis of Revenue by Detailed Rate Schedule
- Exhibit CNG/607 Residential Impact by Month
- Exhibit CNG/608 Impact of Recommended Rate Changes
- Exhibit CNG/609 Ronald J. Amen Statement of Qualifications

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II. THEORETICAL PRINCIPLES OF COST ALLOCATION

Q. Why do utilities conduct cost allocation studies as part of the regulatory process?

A. There are many purposes for utilities conducting cost allocation studies, ranging from designing appropriate price signals in rates to determining the share of costs or revenue requirements borne by the utility's various rate or customer classes. In this case, an LRIC study is a useful tool for determining the allocation of Cascade's revenue requirement among its rate schedules. It is also a useful tool for rate design because it can identify the important cost drivers associated with serving customers and satisfying their design day demands.

Q. Please describe the various types of cost of service studies that may be useful to a utility for rate design and the allocation of revenue requirements.

A. In general, cost of service studies can be based on embedded costs or marginal costs. Marginal costs can be thought of as the change in costs associated with a one unit change in service (or output) provided by the utility. LRIC is a variant of the marginal cost approach that examines changes in costs over a longer time period associated with a multiple unit (*i.e.*, incremental) change in service. As a result of using an incremental change, capacity additions tend to be lumpy and may reflect more capacity additions than those required to serve the increment of load assumed in the analysis. To avoid this issue requires that the computation of the unit cost be based on the amount of capacity added rather than on the level of load that can be served.

Embedded cost studies analyze the costs for a test period based on either the book value of accounting costs (an historical period) or the estimated book value of costs for a forecast test year or some combination of historical and future costs. Where

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a forecast test year is used, the costs and revenues are typically derived from budgets prepared as part of the utility's financial plan. Typically, embedded cost studies are used to allocate the revenue requirement between jurisdictions, classes, and between customers within a class.

Marginal cost studies can reflect incurred costs but often rely on estimates of the expected changes in cost associated with changes in utility service. Marginal cost studies are forward-looking to the extent permitted by available data. Marginal cost studies are particularly useful for rate design and can also be used as a guide to determine how a utility's total revenue requirement should be allocated to its classes of service. Where it is important to send appropriate price signals associated with additional energy consumption by customers, an understanding of marginal cost may be useful. For a gas utility, detailed studies are not required to assess the impact of additional consumption by existing customers since the delivery system is built for design day requirements and energy conservation has reduced those requirements for most customers. Where new customers are added to the system, growth may increase design day requirements above an amount that existing facilities can serve. The principal factors driving new main investment are customer growth and the replacement of bare steel and cast iron mains to provide safe and reliable service for customers.

Q. Please discuss the reasons that cost of service studies are utilized in regulatory proceedings.

A. Cost of service studies represent an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop cost studies results from the nature of utility costs. Utility costs are

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characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more classes, or the cost of providing multiple products to the same class, use the same facilities and the use by one class precludes the use by another class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of throughput, while variable costs change directly with changes in throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains and service lines, meters, and regulators. The distribution assets of a gas utility do not vary with the level of throughput in the short run. In the long run, main costs vary with either growing design day demand or a growing number of customers.

Finally, utility costs exhibit significant economies of scale. Scale economies result in declining average cost as gas throughput increases and marginal costs must be below average costs. These characteristics have implications for both cost analysis and rate design from a theoretical and practical perspective. The development of cost studies, on either a marginal or embedded cost basis, requires an understanding of the operating characteristics of the utility system. Further, as discussed below, different cost studies provide different contributions to the development of economically efficient rates and the cost responsibility by customer class.

Q. Please discuss the application of economic theory to cost allocation.

A. The allocation of costs using cost of service studies is not a theoretical economic exercise. It is rather a practical requirement of regulation since rates must be set based on the cost of service for the utility under cost-based regulatory models. As a general

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matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing that revenue requirement. Using the information developed in the cost of service study to understand and quantify the allocated costs in each rate class to guide the development of rates is a useful step in the rate design process.

However, the existence of common costs makes any allocation of costs problematic from a strict economic perspective. This is theoretically true for any of the various utility costing methods that may be used to allocate costs. Theoretical economists have developed the theory of subsidy-free prices to evaluate traditional regulatory cost allocations. Prices are said to be subsidy-free so long as the price exceeds marginal cost, but is less than stand-alone costs (SAC). The logic for this concept is that if customers' prices exceed marginal cost, those customers make a contribution to the fixed costs of the utility. All other customers benefit from this contribution to fixed costs because it reduces the cost they are required to bear. Prices must be below the SAC because the customer would not be willing to participate in the service offering if prices exceed SAC.

SAC is an important concept for Cascade because certain customers have competitive options for the end uses supplied by natural gas through the use of alternative fuels. As a result, subsidy-free prices permit all customers to benefit from the system's scale and common costs, and all customers are better off because the system is sustainable. If strict application of the cost allocation study suggests rates that exceed

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SAC for some customers, prices must nevertheless be set below the SAC, but above marginal cost, to ensure that those customers make the maximum practical contribution to the common costs of the utility.

Q. If any allocation of common cost is problematic from a theoretical perspective, how is it possible to meet the practical requirements of cost allocation?

A. As noted above, the practical reality of regulation often requires that common costs be allocated among jurisdictions, classes of service, rate schedules, and customers within rate schedules. The key to a reasonable cost allocation is an understanding of cost causation. From a cost of service perspective, the best approach is to directly assign costs where costs are incurred for a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate schedule, or class, uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the manner in which customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, meter costs are customer-related, but differences in the cost of meters are reflected by using a different meter cost for each class of service. For some classes such as the largest customers, the meter cost may be unique for each customer.

Q. Please discuss the elements of Cascade's LRIC analysis.

A. As I introduced earlier, LRIC is a costing method based on principles of marginal costs. Since marginal costs are forward-looking in nature, they require making estimates of future costs with an understanding of the elements that drive those future costs.

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To estimate LRIC, the first step requires determining the change in cost associated with the incremental consumption of natural gas. For LRIC, the increment may be defined as the number of customers, the design day demand, or the additional commodity. In this case, there is no reason to estimate the incremental commodity because gas costs are a pass-through cost element. Essentially, LRIC requires an understanding of the utility's system planning process. Often, however, the planning process does not provide all the information necessary to develop complete LRIC estimates.

The second step in the determination of LRIC relates to the change in capacity requirements as measured by the utility's design day demand. Unlike the commodity determination, there is no competitive market for the utility's distribution function. Thus, it is necessary to estimate how customers' demand for design day capacity influences the costs for distribution. The capacity requirements for the distribution system must reflect the non-coincident demands on the system since delivery must satisfy the local demands of customers that may not be coincident with the system peaks for many reasons. Although, for customers who use the utility's gas delivery system for heating as opposed to process usage or interruptible services, their demands tend to be coincident. For process and interruptible customers, LRIC is zero for existing customers unless the customer expands its operations. If expansion occurs, LRIC is the cost incurred to expand capacity to meet the customer's increased contracted demand.

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III. CASCADE'S LRIC STUDY

Q. Have you prepared Cascade's LRIC Study filed in this proceeding?

A. Yes. Exhibit CNG/601 presents Cascade's LRIC Study. In particular, the exhibit presents the resulting allocation by rate schedule of Cascade's proposed revenue requirement based strictly on the results of the LRIC computations included in the LRIC Study.

Q. Please describe the methodology used to prepare Cascade's LRIC Study.

A. Cascade has chosen to follow a similar methodology as that employed previously by the Company in Docket UG 287 and UG 305. The primary elements of Cascade's LRIC Study are incremental plant investments and incremental operations and maintenance expenses (O&M). The incremental cost information related to these elements are accumulated on a cost per customer basis for each of Cascade's tariff rate schedules summarized to represent the long-run incremental cost for customers on Cascade's distribution system.

A. Incremental Plant Investment Costs

Q. What are the components of Cascade's incremental plant investment?

A. Cascade's incremental plant investment has three primary components. These components are:

1. The costs to install distribution mains in order to: a) connect new customers, b) provide capacity reinforcements to both new and existing customers, c) address safety and reliability requirements for the benefit of all customers, and d) invest in long-term system main replacement;

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2. The cost to provide a service line to connect new customers; and

3. The cost to provide a meter and regulator to serve new customers.

Q. How is the cost to install distribution mains determined for the various functions described in the previous response?

A. The first component of Cascade's distribution mains analysis derives the customer related costs associated with the installation of distribution mains to connect new customers. Mains investments that serve this function were extracted from Cascade's plant accounting records. Oregon new business project work orders were summarized for a sixteen-year period (2002 – 2017). The customer cost was computed by taking the average cost per foot of Cascade's minimum-sized distribution main (two-inch), escalated to current dollars (2017) using the Handy Whitman Index of Public Utility Construction Costs, and multiplying that unit cost by the number of feet of main installed per new customer for Residential (Schedule No. 101), Commercial (Schedule No. 104), and Industrial (Schedule No. 105) service classes. For the larger core classes (Schedule No. 111 and Schedule No. 170) and the non-core class (Schedule No. 163), as well as the Special Contract Class (Schedule No. 900), the distribution main segments connected to the individual customers were identified using Cascade's Geographic Information System (GIS). The in-service date of the main segment, its size, type and length were compiled and current costs (2017 dollars) applied to compute the corresponding installed costs. For smaller core classes (Schedule Nos. 101 and 104), a regression analysis was performed on a sample of recent work order main extensions to determine the typical feet of mains per customer. For Schedule No. 105, twenty-one main extension work orders were used as a representative sample.

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Q. How were the incremental cost of distribution mains determined for long-term system replacement investments?

A. Long-term distribution mains replacement costs were estimated by calculating the current cost of Oregon mains in service at December 2017. Current costs of the prior category of distribution mains, new customer main extensions, were deducted to determine the remaining level of system replacement investment. This remaining investment was separated into capacity versus commodity components using Cascade's Oregon system load factor and then allocated to the appropriate classes using design day demand and annual throughput, respectively.

Q How were the incremental costs for the two categories of mains then computed for the LRIC Study?

A. Once the investment costs for all mains were derived, the incremental costs were computed by applying an Economic Carrying Charge Rate (ECCR) to the investment costs. The derivation of the LRIC for distribution mains is presented in Exhibit CNG/603, Plant Carrying Costs.

Q. How are the costs of services, meters, and regulators determined?

A. Cascade's LRIC Study derives the incremental costs of installing new services using Cascade's recent actual installation costs from 2009 to 2017 escalated to 2017 dollars using the Handy Whitman Index of Public Utility Construction Costs. For services, the investment costs are based on the installed cost for customers' typical size and type for each core customer class 101, 104 and 105. Similarly, the investment costs for meters and regulators are based on the installed average cost of metering and regulating equipment for these core classes utilizing current 2017 inventory prices. For the

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remaining larger customer classes 111, 170, 163, and the Special Contract class 900, the service, metering and regulating installations were specifically identified for each customer using the Cascade GIS system and then valued at current cost. Once the investment costs were derived, the incremental costs were computed by applying the ECCR to the investment costs. The derivation of the LRIC for services and meters is presented in Exhibit CNG/603.

Q. How does the investment in meters, services and mains impact LRIC calculation through the use of the ECCR?

A. The investment in meters, services and mains plant are multiplied by an ECCR to arrive at an annualized cost associated with these capital investments. Separate ECCRs were calculated for meters, services and mains. The three ECCRs are different because asset life and depreciation methods are different for each of these asset classes.

Q. Please explain the ECCR.

A. The ECCR is defined as the levelized economic cost per unit of book value investment. Economic cost reflects true cost associated with owning and operating an asset. It is different from expenses in that it accounts for return on capital that is required to make an investment. The carrying charge includes: a) a required return on and of capital component, b) an operations and maintenance cost component, c) an administrative and general cost component, and d) corresponding tax effects.

B. Incremental Operating & Maintenance Expenses

Q. Please identify the costs included in gas supply related O&M expenses and how these costs were treated in the LRIC?

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A. The category of gas supply O&M expenses includes salaries and benefits of personnel in the following responsibility centers: Gas Supply Resource Planning (RC 4761100), Gas Supply (RC 4761200), Gas Control (RC 4763200), and a Management expense allocation from MDU (RC 4766000). The corresponding labor expenses were distributed among the three categories of Gas Planning, Gas Supply and Gas Control based on the time allocations reported by the personnel in these responsibility centers.

The Gas Planning function includes monthly/seasonal/annual gas resource planning; supply resource modeling and optimization; market intelligence gathering and analysis; Integrated Resource Plan development; and Canadian/U.S. pipeline and storage operational, tolls/tariffs, and shipper-related activities. The expenses charged to this function were first segregated between core and non-core classes according to the assigned labor hours and then allocated among the core and non-core classes using a peak and average allocator.

The Gas Supply function includes gas supply procurement for core customers; balancing of core system supplies, including day-to-day storage activities; gas supply reporting, including commodity and closing price reporting; processing supplier invoices; updating and maintaining North American Energy Standards Board (NAESB) contracts; and tracking import authorizations and North American Free Trade (NAFTA) certificates. Types of activities relating to non-core customers include resolution of imbalances and communicating with non-core customers relating to imbalance "packing" or "drafting" that affects the overall system balance position. The expenses charged to this function were first segregated between core and non-core classes according to the

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assigned labor hours and then allocated among the core and non-core classes using sales or transportation volumes, respectively.

The Gas Control function entails the 24-hour daily monitoring and management of the flow of gas on the Cascade pipeline system in Oregon. This is accomplished by gas control personnel through electronic monitoring of various points on the system via SCADA and Metretek measurement equipment. The SCADA sites are located at town border stations throughout the Cascade system and at one Special Contract customer location. Metretek monitoring equipment is located at non-core customer locations for classes 170, 163 and 900. The expenses charged to this function were first segregated between core and non-core classes according to a recent twelve-month study of recorded actionable items triggered by information provided by the SCADA and Metretek sites, and then allocated among the core and non-core classes using sales or transportation volumes, respectively. The results of the foregoing allocations of gas supply related O&M are shown on Line 26 of Exhibit CNG/604.

Q. Please describe the costs included in incremental customer service related O&M expenses and how these costs were treated in the LRIC Study.

A. The category of incremental customer related O&M expenses includes Meter Reading (FERC Account 902); Customer Records and Collections, including monthly billing postage and printing (FERC Account 903); and Uncollectible Accounts (FERC Account 904), involving the following Cascade Responsibility Centers: Customer Services (RC 4767100, RC 4767200, RC 4767300, RC 4767400, RC 4760800); Credit and Collections (RC 4767000); Revenue Accounting (RC 4760700, RC 4769400); Information Systems

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(RC 4767500, RC 4767800); and Oregon Districts (Bend RC 47041/47044), Pendleton (RC 47042), and Eastern Oregon (RC 47043).

Meter Reading expenses were assigned to core or non-core customer groups based on an analysis of labor costs of field personnel involved in meter reading activities related to the respective customer groups and then allocated on a customer basis. Customer Records and Collections expenses were allocated to all classes on a customer basis after first directly assigning a portion of the expenses to the classes that receive manual billing (i.e., 163, 170, and 900). Uncollectible Accounts expenses were assigned to the classes based on uncollectible account write-offs. The results of the foregoing allocations of customer service related O&M are shown on Line 45 of Exhibit CNG/604.

C. LRIC Summary of Results

Q. Please compare the resulting LRIC estimates to the current rates and associated non-gas revenues for each of Cascade's rate schedules.

A. Line 38 of Exhibit CNG/601 presents the total LRIC-based revenue requirement for each of Cascade's rate schedules. Line 33 of this Exhibit presents Test Year revenues by rate schedule under Cascade's current rates. By comparing these two sets of revenues, one can see the extent to which Cascade's current rates and non-gas revenues are reflective of LRIC. The revenue-to-cost ratios on line 39 of this exhibit portray the relative difference between these two revenue amounts for each rate schedule. A revenue-to-cost ratio of less than 1.00 means that the current rates and revenues of the particular rate schedule are below its indicated LRIC (*e.g.*, Rate Schedules 101, 105,

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and 163), while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the rate schedule are above its indicated LRIC (*e.g.*, Rate Schedules 104, 111, 170, Special Contract 902-2, and the remaining Special Contract Class 900).[1] These results provide cost guidelines for use in evaluating a utility's class revenue levels and rate structures. I will describe later in my testimony how these results were used to assign Cascade's proposed revenue increase to its rate classes.

Q. What was the source of the revenue requirement components?

A. Exhibit CNG/602 shows how the pro forma results of Cascade's operations, including the requested revenue increase discussed in Company witness Ms. Peters' Exhibit CNG/301, have been assigned to the functional components used in the LRIC.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. Please identify the principles of rate design you have relied upon as the basis for Cascade's rate design proposals.

A. A number of rate design principles or objectives find broad acceptance in utility regulatory and policy literature. These include:

1. Efficiency;
2. Cost of Service;
3. Value of Service;
4. Stability;

[1] Due to the expected termination of Special Contract 902-2, the current term of which is set to expire on March 31, 2019, this customer has been separated from the Special Contract class for purposes of the LRIC. The terms under which this customer may contract for delivery service following the Special Contract expiration has yet to be determined.

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5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in *Principles of Public Utility Rates*.[2] Each of these principles plays an important role in analyzing the rate design proposals of Cascade.

Q. Please discuss the principle of efficiency.

A. The principle of efficiency broadly incorporates both economic and technical efficiency. As such, this principle has both a pricing dimension and an engineering dimension. Economically efficient pricing promotes good decision-making by gas producers and consumers, fosters efficient expansion of delivery capacity, results in efficient capital investment in customer facilities, and facilitates the efficient use of existing gas pipeline, storage, transmission, and distribution resources. The efficiency principle benefits stakeholders by creating outcomes for regulation consistent with the long-run benefits of competition while permitting the economies of scale consistent with the best cost of service. Technical efficiency means that the development of the gas utility system is designed and constructed to meet the design day requirements of customers using the most economic equipment and technology consistent with design standards.

Q. Please discuss the cost of service and value of service principles.

[2] James Bonbright, *Principles of Public Utility Rates* 382-384 (2d ed. 1998).

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A. These principles each relate to designing rates that recover the utility's total revenue requirement without causing inefficient choices by consumers. The cost of service principle contrasts with the value of service principle when certain transactions do not occur at price levels determined by the embedded cost of service. In essence, the value of service acts as a ceiling on prices. Where prices are set at levels higher than the value of service, consumers will not purchase the service. This principle puts the concept of SAC, discussed above, into practice and is particularly relevant for Cascade because of the competitive supply alternatives that cap rates under its special contracts.

Q. Please discuss the principle of stability.

A. The principle of stability typically applies to customer rates. This principle suggests that reasonably stable and predictable prices are important objectives of a proper rate design.

Q. Please discuss the concept of non-discrimination.

A. The concept of non-discrimination requires prices designed to promote fairness and avoid undue discrimination. Fairness requires no undue subsidization either between customers within the same class or across different classes of customers.

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that

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"equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal—rates should be equal and, where costs are different—rates should be different. In this case, this principle is an important requirement that supports Cascade's proposed use of a single monthly Basic Service Charge for all customers within certain of its rate schedules, because delivery costs are identical for its residential customers and for its smallest commercial customers.

Q. Please discuss the principle of administrative simplicity.

A. The principle of administrative simplicity as it relates to rate design requires that prices be reasonably simple to administer and understand. This concept includes price transparency within the constraints of the ratemaking process. Prices are transparent when customers are able to reasonably calculate and predict bill levels and interpret details about the charges resulting from the application of the tariff.

Q. Please discuss the principle of the balanced budget.

A. This principle permits the utility a reasonable opportunity to recover its allowed revenue requirement based on the cost of service. Proper design of utility rates is a necessary condition to enable an effective opportunity to recover the cost of providing service included in the revenue authorized by the regulatory authority. This principle is very similar to the stability objective that I previously discussed from the perspective of customer rates.

Q. Can the objectives inherent in these principles compete with each other at times?

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right

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balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

Q. Please describe the conflict between marginal cost price signals and the recovery of the utility's revenue requirement.

A. The conflict between proper price signals based on marginal cost and the balanced budget principle arises because marginal cost is below average cost due to economies of scale. Where fixed delivery service costs do not vary with the volume of gas sales, marginal costs for delivery equal zero. Marginal customer costs equal the additional cost of the customer accessing the entire gas delivery system. Marginal cost tends to be either above or below average cost in both the short run and the long run. This means that marginal cost-based pricing will produce either too much or too little revenue to support the utility's total revenue requirement. This suggests that efficient price signals may require a multi-part tariff designed to meet the utility's revenue requirements while sending marginal cost price signals related to gas consumption decisions. Properly designed, a multi-part tariff may include elements such as access charges, facilities charges, demand charges, consumption charges, and the potential for revenue credits.

In the case of a local distribution company (LDC) such as Cascade, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that

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is derived on an embedded cost basis. For larger customers, a combination of these elements permit proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

A. Yes. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. Please summarize Bonbright's three primary criteria for sound rate design.

A. Bonbright identifies the three primary criteria for sound rate design as follows:

- Capital Attraction,
- Consumer Rationing, and
- Fairness to Ratepayers.[3]

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction

[3] *Id.* at 385.

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is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

Q. How are these principles translated into the design of retail gas rates?

A. The process of developing rates within the context of these principles and conflicts requires a detailed understanding of all the factors that impact rate design. These factors include:

1. System cost characteristics such as LRIC required by the OPUC, or embedded customer, demand, and commodity related costs by type of service;
2. Customer load characteristics such as peak demand, load factor, seasonality of loads, and quality of service;
3. Market considerations such as elasticity of demand, competitive fuel prices, end-use load characteristics, and LDC bypass alternatives; and
4. Other considerations such as the value of service ceiling/marginal cost floor, unique customer requirements, areas of underutilized facilities, opportunities to offer new services and the status of competitive market development.

In addition, the development of rates must consider existing rates and the customer impact of modifications to the rates. In each case, a rate design seeks to recover the authorized level of revenue based on the billing determinants expected to occur during the test period used to develop the rates.

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures

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within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Cascade's proposed revenue increase of $2.3 million to its rate classes.

A. As just described, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations. These criteria were evaluated for each of Cascade's rate classes. Based on this evaluation, adjustments to the present revenue levels in each of Cascade's rate classes were made so that its proposed rates moved class revenues closer to the LRIC of serving each rate class.

Q. Did you consider various class revenue options in conjunction with your evaluation and determination of Cascade's interclass revenue proposal?

A. Yes. Using Cascade's proposed revenue increase, and the results of its LRIC Study, I evaluated various options for the assignment of that increase among its rate classes and, in conjunction with Cascade personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The first

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and benchmark option that I evaluated under Cascade's proposed total revenue level was to adjust the revenue level for each rate class so that the revenue-to-cost for each class was equal to 1.00. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

The second option I considered was assigning the increase in revenues to Cascade's rate classes based on an equal percentage basis of its current base (non-gas) revenues. By definition, this option resulted in each rate class receiving an increase in revenues. However, when this option was evaluated against the LRIC Study results (as measured by changes in the revenue-to-cost ratio for each rate class); there was no movement towards cost for some of Cascade's rate classes (*i.e.*, there was no convergence of the resulting revenue-to-cost ratios towards unity or 1.00). While this option also was not the preferred solution to the interclass revenue issue, together with the fully cost-based option, it defined a range of results that provided me with further guidance to develop Cascade's class revenue proposal.

Q. What was the next step in the process?

A. After further discussions with Cascade, I concluded that the appropriate interclass revenue proposal would be one that reflects increases in revenues to certain rate classes, guided by the results of Cascade's LRIC Study, with increases to these rate classes moderated by establishing a maximum increase level above Cascade's

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proposed overall increase in non-gas revenues of 3.00. This approach established a maximum non-gas revenue increase to any particular rate class of 21.67% (3.00 times 7.22%). Exhibit CNG/601 presents the derivation of Cascade's proposed class margin revenues by rate schedule on Line 49.

This preferred revenue allocation approach resulted in reasonable movement of the class revenue-to-cost ratios towards unity or 1.00. That result is reflected in Exhibit CNG/601 on Line 51, wherein the revenue-to-cost ratios are shown to converge towards unity or 1.00 compared to the same measure calculated under current rates. In addition, the amounts of the existing rate subsidies among Cascade's rate classes were reduced for those classes that received increases in revenues. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable.

Q. Have you prepared a comparison of Cascade's present and proposed revenues by rate schedule?

A. Yes. Exhibit CNG/605 presents a comparison of present and proposed revenues for each of Cascade's rate schedules.

VI. SUMMARY OF CASCADE'S RATE DESIGN PROPOSALS

Q. Please summarize the rate design changes Cascade has proposed in this rate proceeding.

A. Cascade has proposed the following rate structure and design changes to its current rate schedules:

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- The establishment of a monthly Basic Service Charge for Schedule No. 111, Large Volume General Service, and Schedule No. 170, Interruptible Service.
- For customers served under Schedule No. 101, General Residential Service, Schedule No. 104, General Commercial Service, Schedule No. 105, General Industrial Service, and Schedule No. 163, Cascade proposes to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service as well as the proposed change in class revenues.
- An additional volumetric rate block to the Delivery Charge of Schedule No. 163 to accommodate the potential migration of a Special Contract customer's high level of monthly gas transportation volumes.
- The establishment of a Contract Demand Charge for Schedule No. 163 of $0.10 per therm of contract demand.

I will present below the specific rate design changes and supporting rationale for Cascade's proposals.

Q. Please explain the reasoning behind the establishment of Basic Service Charges for Schedule No. 111 and Schedule No. 170.

A. In the interest of providing improved cost-based price signals to all of its classes of service, Cascade believes that it is appropriate for all service schedules to recover a portion of the customer-related incremental O&M and carrying costs of its incremental meter and service investment in a monthly Basic Service Charge. The LRIC Study provides a guide for this purpose. Line 55 of Exhibit CNG/601 shows the incremental customer-related O&M by class, including meter reading, customer account records and collection, billing and postage and uncollectible expenses. Line 54 of Exhibit CNG/601 adds the carrying

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charges on the meter and service investment by class to the incremental O&M. The cost values are stated on a per-month basis. This provides a range of incremental customer-related O&M cost recovery from which to design a monthly Basic Service Charge for each class of service. Cascade is proposing to establish the Basic Service Charge for Schedule No. 111 at $125.00 per month, approximately 34% of the upper range of incremental customer-related O&M and meter and service carrying charges for the class. The initial proposed Basic Service Charge for Schedule No. 170 was set at $300.00 per month, approximately 19% of the upper range of incremental customer-related O&M and meter and service carrying charges for the class.

Q. Please describe the changes to the monthly Customer Charge levels for Schedule No. 101, Schedule No. 104, Schedule No. 105 and Schedule No. 163.

A. The proposed monthly Basic Service Charge for Schedule No. 101 is $5.00, approximately 23% of the upper range of the incremental customer-related O&M and meter and service carrying charges for this class. The proposed monthly Basic Service Charge for Schedule No. 104 is $10.00, approximately 28% of the upper range of the incremental customer-related O&M and meter and service carrying charges for this class, as indicated in the LRIC Study. The proposed monthly Basic Service Charge for Schedule No. 105 is $30.00, approximately 26% of the upper range of the incremental customer-related O&M and meter and service carrying charges for the class. The Basic Service Charge for proposed for Schedule No. 163 is $625.00, which raises the charge to within 50% of the upper range of the indicated incremental customer-related O&M and meter and service carrying charges for the class.

Q. Please describe the proposed structural changes to Schedule No. 163.

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A. Due to the expected termination of Special Contract 902-2, the current term of which is set to expire on March 31, 2019, an additional volumetric rate block to the Delivery Charge of Schedule No. 163 has been added to accommodate the migration of this Special Contract customer's high monthly gas transportation volumes. The Company has notified this Special Contract customer that the current contract will not be renewed. The addition of a new tail block for monthly volumes exceeding 1,000,000 therms will have a negligible impact on the annual bill for this customer. In addition, a Contract Demand Charge is proposed for Schedule No. 163 to reflect the conversion of this transportation service from interruptible to firm.

Q. Have you provided an Exhibit that depicts the proposed rates for all classes of service?

A. Yes. Exhibit CNG/606 shows the derivation of each rate component for each of Cascade's service schedules.

Q. Has a revenue proof been prepared to show that Cascade's proposed rates generate the total distribution revenue and total revenue increase it has proposed in this proceeding (*i.e.* its total non-gas revenue)?

A. Yes. Cascade witness Isaac Myhrum presents Cascade's revenue proof for the Test Year in Exhibit CNG/401.

VII. CUSTOMER BILL IMPACTS

Q. Please describe the bill impacts for residential customers under Cascade's rate design proposal.

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A. The monthly and annual bill impacts for a typical residential customer using 688 therms per year is shown on Exhibit CNG/607. The average monthly increase for this residential customer under the Company's proposed rate design is $2.38 or 4.94%, including gas costs. Average monthly residential bill impacts are depicted on page 1 of Exhibit CNG/607 and bill impacts over varying monthly levels of usage is presented on page 1 of Exhibit CNG/608.

Q. Have you prepared bill comparisons for Cascade's other rate classes?

A. Yes. Pages 2 through 6 of Exhibit CNG/608 presents bill comparisons for Cascade's non-residential service schedules at varying monthly levels of gas usage.

Q. Does this conclude your direct testimony?

A. Yes.

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CNGC/601
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 601

Summary of LRIC

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Summary

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Transportation non-core	902-2 Special Contract non-core	170 Interruptible core	9xx Special Contracts non-core
1	Billing Determinants									
2	Peak Day Forecast	97,866	49,348	34,175	3,188	936	10,218	-	-	-
3	Customer Count	72,730	62,493	10,031	148	18	32	1	4	3
4	Throughput	30,693,226	4,297,744	3,028,642	203,763	162,996	3,155,252	16,953,916	241,847	2,649,066
5	O&M Costs									
6	Gas Supply Related									
7	Gas Planning	$ 83,952	$ 36,617	$ 25,455	$ 2,229	$ 845	$ 4,497	$ 11,988	$ 448	$ 1,873
8	Gas Supply	$ 40,673	$ 17,289	$ 12,184	$ 820	$ 656	$ 2,144	$ 5,715	$ 973	$ 893
9	Gas Control	$ 77,626	$ 28,852	$ 20,332	$ 1,368	$ 1,094	$ 11,036	$ 11,353	$ 1,624	$ 1,966
10	Customer Related									
11	Meter Reading	$ 260,870	$ 218,566	$ 35,085	$ 518	$ 2,080	$ 3,698	$ 116	$ 462	$ 347
12	Customer Account records and collection	$ 1,318,539	$ 1,126,528	$ 180,832	$ 2,668	$ 324	$ 6,549	$ 205	$ 819	$ 614
13	Billing Postage & Printing	$ 367,765	$ 315,999	$ 50,725	$ 748	$ 91	$ 162	$ 5	$ 20	$ 15
14	Uncollectible	$ 319,056	$ 283,335	$ 35,720	$ -	$ -	$ -	$ -	$ -	$ -
15	Subtotal: O&M Costs	$ 2,468,481	$ 2,027,187	$ 360,332	$ 8,351	$ 5,091	$ 28,085	$ 29,382	$ 4,345	$ 5,708
16	Customer Investment Carrying Costs									
17	Meter	$ 5,485,121	$ 3,181,445	$ 1,630,225	$ 112,925	$ 57,978	$ 390,919	$ 34,756	$ 50,098	$ 26,775
18	Service	$ 13,625,113	$ 11,093,183	$ 2,309,911	$ 85,452	$ 18,638	$ 88,288	$ 165	$ 23,356	$ 6,121
19	Mains	$ 12,185,198	$ 6,913,979	$ 2,213,735	$ 1,008,043	$ 151,080	$ 988,956	$ 668,055	$ 165,151	$ 76,199
20	Subtotal: Customer Investment Costs	$ 31,295,432	$ 21,188,607	$ 6,153,871	$ 1,206,420	$ 227,696	$ 1,468,163	$ 702,976	$ 238,605	$ 109,094
21	System Core Main Carrying Costs									
22	Capacity	$ 34,390,164	$ 17,341,124	$ 12,009,090	$ 1,120,422	$ 328,903	$ 3,590,624	$ -	$ -	$ -
23	Commodity	$ 9,820,990	$ 3,805,877	$ 2,682,021	$ 180,443	$ 144,341	$ 2,794,141	$ -	$ 214,168	$ -
24	Subtotal: System Core Main Costs	$ 44,211,154	$ 21,147,001	$ 14,691,111	$ 1,300,865	$ 473,244	$ 6,384,765	$ -	$ 214,168	$ -
25	LRIC - Distribution	$ 77,975,067	$ 44,362,795	$ 21,205,315	$ 2,515,636	$ 706,031	$ 7,881,014	$ 732,358	$ 457,118	$ 114,802
26	Functional Cost Assignment by LRIC									
27	Scheduling & Planning	$ 202,251	$ 82,758	$ 57,971	$ 4,417	$ 2,595	$ 17,677	$ 29,056	$ 3,044	$ 4,732
28	Meter Reading, Billing etc.	$ 2,266,229	$ 1,944,429	$ 302,361	$ 3,934	$ 2,495	$ 10,408	$ 325	$ 1,301	$ 976
29	Meters & Services	$ 19,110,234	$ 14,274,628	$ 3,940,136	$ 198,377	$ 76,616	$ 479,207	$ 34,920	$ 73,454	$ 32,895
30	Mains Extensions	$ 12,185,198	$ 6,913,979	$ 2,213,735	$ 1,008,043	$ 151,080	$ 988,956	$ 668,055	$ 165,151	$ 76,199
31	System Core Mains	$ 44,211,154	$ 21,147,001	$ 14,691,111	$ 1,300,865	$ 473,244	$ 6,384,765	$ -	$ 214,168	$ -
32	Total	$ 77,975,067	$ 44,362,795	$ 21,205,315	$ 2,515,636	$ 706,031	$ 7,881,014	$ 732,358	$ 457,118	$ 114,802

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Summary

			101	104	105	111	163	902-2	170	9xx
Line	Description	Total	Residential Service	Commercial Service	Industrial Service	Large Volume Service	General Transportation	Special Contract	Interruptible	Special Contracts
			core	core	core	core	non-core	non-core	core	non-core
33	Non-Gas Revenue at Current Rates	$ 31,989,470	$ 18,646,449	$ 8,435,632	$ 440,188	$ 270,442	$ 2,166,656	$ 1,357,481	$ 297,689	$ 374,934
34	Scheduling and Planning	$ 489,249	$ 200,194	$ 140,233	$ 10,684	$ 6,278	$ 42,761	$ 70,288	$ 7,364	$ 11,448
35	Meter Reading & Billing	$ 3,659,158	$ 3,139,564	$ 488,206	$ 6,352	$ 4,029	$ 16,806	$ 525	$ 2,101	$ 1,576
36	Meters & Services	$ 12,926,276	$ 9,655,443	$ 2,665,131	$ 134,184	$ 51,824	$ 324,139	$ 23,620	$ 49,685	$ 22,251
37	Mains	$ 17,042,357	$ 8,417,523	$ 5,070,990	$ 692,609	$ 187,280	$ 2,211,914	$ 200,398	$ 113,785	$ 147,858
38	Total LRIC Based Non-gas Rev Req.	$ 34,117,040	$ 21,412,724	$ 8,364,560	$ 843,828	$ 249,411	$ 2,595,619	$ 294,831	$ 172,935	$ 183,131
39	Revenue to Cost Ratio	0.94	0.87	1.01	0.52	1.08	0.83	4.60	1.72	2.05
40	Incremental Non-gas Revenue Requirement	$ 2,310,808								
41	Step 1									
42	Increase relative to system average			-	3.00	-	2.75	-	-	-
43	Percent Increase	7.22%		0.00%	21.67%	0.00%	19.87%	0.00%	0.00%	0.00%
44	Increase Step 1	$ 525,800		$ -	$ 95,393	$ -	$ 430,407	$ -	$ -	$ -
45	Step 2									
46	Remainder allocated on Current Revenue	$ 18,646,449	$ 18,646,449	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	Increase Step 2	$ 1,785,008	$ 1,785,008	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Total Non-gas Revenue Increase	$ 2,310,808	$ 1,785,008	$ -	$ 95,393	$ -	$ 430,407	$ -	$ -	$ -
49	Non-Gas Revenue after Revenue Increase	$ 34,300,278	$ 20,431,456	$ 8,435,632	$ 535,581	$ 270,442	$ 2,597,063	$ 1,357,481	$ 297,689	$ 374,934
50	Percent Increase		9.57%	0.00%	21.67%	0.00%	19.87%	0.00%	0.00%	0.00%
51	Revenue to Cost Ratio		0.95	1.01	0.63	1.08	1.00	4.60	1.72	2.05
52	Final Increase relative to system average		1.33	-	3.00	-	2.75	-	-	-
53	LRIC Supported Customer Cost per month									
54	Cust O&M Plus Meter & Service Carrying Charge		$ 21.63	$ 35.24	$ 113.91	$ 366.26	$ 1,275.04	$ 2,937.14	$ 1,557.40	$ 940.87
55	Cust O&M		$ 2.59	$ 2.51	$ 2.22	$ 11.55	$ 27.10	$ 27.10	$ 27.10	$ 27.10

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 602

Functional Revenue Requirement

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Functionalization

No.	FERC	Description	2017 Results	Adjustments	Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains
		Plant In Service								
1		Intangible Plant	$ 12,349,255	$ 466,101	$ 12,815,356	Plant	$ -	$ -	$ 5,222,536	$ 7,592,820
2		Production Plant			-					
3		Storage Plant			-					
4		Transmission Plant	6,260,460		6,260,460					6,260,460
5		Distribution Plant			-					-
6	374	Land and Land Rights	400,567		400,567					400,567
7	375	Structures and Improvements	463,423		463,423					463,423
8	376	Mains	92,660,285	15,091,758	107,752,043					107,752,043
9	377	Compressor Station	-		-					-
10	378	M & R Station Equipment	10,342,137	539,046	10,881,183					10,881,183
11	380	Services	51,350,518	1,658,069	53,008,587				53,008,587	
12	381	Meters	14,676,176	4,289,100	18,965,276				18,965,276	
13	382	Meter Install	9,108,507	571,699	9,680,206				9,680,206	
14	383	House Regulator & Install.	2,706,169	132,901	2,839,069				2,839,069	
15	385	Industrial M & R Station Equipment	1,877,868	128,348	2,006,216				2,006,216	
16		General Plant	17,788,276	1,675,035	19,463,311	Plant	-	-	7,931,722	11,531,588
17		Subtotal Plant In Service	$ 219,983,640	$ 24,552,055	$ 244,535,695		$ -	$ -	$ 99,653,612	$ 144,882,083
18		**Accumulated Depreciation**								
19		Intangible Plant	$ (3,533,483)	$ (858,337)	$ (4,391,819)	Plant	$ -	$ -	$ (1,789,762)	$ (2,602,057)
20		Production Plant			-					
21		Storage Plant			-					
22		Transmission Plant	(3,506,629)	(113,051)	(3,619,680)					(3,619,680)
23		Distribution Plant	(88,295,492)	(5,927,499)	(94,222,992)	DistPlant	-	-	(39,564,872)	(54,658,120)
24		General Plant	(6,753,314)	(406,444)	(7,159,758)	Plant	-	-	(2,917,757)	(4,242,001)
25		Subtotal Accumulated Depreciation	$ (102,088,918)	$ (7,305,331)	$ (109,394,249)		$ -	$ -	$ (44,272,391)	$ (65,121,858)
26		**Other Ratebase Items**								
27		Contributions in Aid of Construction	$ -	$ -	$ -					
28		Customer Adv. For Construction	(408,596)	-	(408,596)				(408,596)	
29		Deferred Accumulated Income Taxes	(26,914,734)	498,717	(26,416,017)	Plant	-	-	(10,765,101)	(15,650,916)
30		Deferred Debits	-	-	-					
31		Working Capital Allowance	2,812,500	-	2,812,500	Plant	-	-	1,146,155	1,666,345
32		Subtotal Other Ratebase	$ (24,510,830)	$ 498,717	$ (24,012,113)		$ -	$ -	$ (10,027,542)	$ (13,984,571)
33		Total Ratebase	$ 93,383,892	$ 17,745,441	$ 111,129,333		$ -	$ -	$ 45,353,679	$ 65,775,654
34		Rate of Return			7.33%					
35		Return on Ratebase			$ 8,140,855		$ -	$ -	$ 3,322,415	$ 4,818,441

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Functionalization

No.	FERC	Description	2017 Results	Adjustments	Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains
36		**Operating Expenses**								
37		Production	$ 101,025	1,717	$ 102,743		$ 102,743			
38		Distribution								
39	870	Operation Supervision & Engineering	735,994		735,994	OpEx	33,849	-	272,381	429,764
40	871	Distribution Load Dispatching	112,679		112,679		112,679			
41	872	Compressor Station	-		-					-
42	874	Mains and Services Expenses	1,223,950		1,223,950					1,223,950
43	875	Meas. & Reg. Station Expenses	186,913		186,913					186,913
44	876	Meas. & Reg. Station Expenses - Ind	19,762		19,762					19,762
45	878	Meter & House Regulator Expenses	458,032		458,032				458,032	
46	879	Customer Installations Expenses	448,688		448,688				448,688	
47	880	Other Expenses	1,599,522		1,599,522	OpEx	73,564	-	591,960	933,998
48	881	Rents	33,201		33,201	Plant	-	-	13,530	19,671
49	885	Maint. Supervision & Engineering	147,320		147,320	MaintExp	-	-	101,985	45,335
50	886	Maint. of Structures & Improvements	179		179					179
51	887	Maint. of Mains	336,082		336,082					336,082
52	888	Maint. of Compressor Station Equip.	(1,269)		(1,269)					(1,269)
53	889	Maint. of Meas. & Reg. Station Expenses-General	53,968		53,968					53,968
54	890	Maint. of Meas. & Reg. Station Expenses-Indust.	8,477		8,477					8,477
55	892	Maint. of Services	476,388		476,388				476,388	
56	893	Maint. of Meters & House Regulators	417,682		417,682				417,682	
57	894	Maint. of Other Equipment	176,967		176,967	MaintExp	-	-	122,508	54,458
58	N/A	Distribution Adjustments		425,888	425,888	DistExp	14,567	-	192,153	219,167
59		Customer Accounts	1,904,929	147	1,905,077			1,905,077		
60		Customer Service	121,204	-	121,204			121,204		
61		Sales	913	(11,482)	(10,569)			(10,569)		
62		Administrative and General	6,213,010	49,491	6,262,500	O&M	151,847	1,643,446	2,133,886	2,333,321
63		Depreciation & Amortization	6,437,588	867,743	7,305,331	Plant	-	-	2,977,081	4,328,250
64		Regulatory Debits	-	-	-	Plant	-	-	-	-
65		Taxes Other Than Income	2,155,564	-	2,155,564	Plant	-	-	878,439	1,277,125
66		State & Federal Income Taxes	1,875,733	(601,819)	1,273,914	Plant	-	-	519,148	754,766
67		Total Operating Expense	$ 25,244,500	$ 731,685	$ 25,976,185		$ 489,249	$ 3,659,158	$ 9,603,862	$ 12,223,916
68		Functionalized Revenue Requirement	$ 25,244,500	$ 731,685	$ 34,117,040		$ 489,249	$ 3,659,158	$ 12,926,276	$ 17,042,357

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 603

Incremental Plant Carrying Costs

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Plant Carrying Costs

Line	Description	Unit	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Transportation non-core	902-2 Special Contract non-core	170 Interruptible core	9xx Special Contracts non-core	Source
1	**Billing Determinants**											
2	Peak Day Forecast	Dth-Day	97,866	49,348	34,175	3,188	936	10,218	-	-	-	
3	Customer Count		72,730	62,493	10,031	148	18	32	1	4	3	
4	Throughput	Dth	30,693,226	4,297,744	3,028,642	203,763	162,996	3,155,252	16,953,916	241,847	2,649,066	
5	**Service Installation**											
6	Typical Size	in.		0.5	1	2						
7	Material			Plastic	Plastic	Plastic						
8	Average Cost	$		$ 1,141	$ 1,480	$ 3,711						RJA-1
9	Total Investment	$	$ 87,579,399	$ 71,304,676	$ 14,847,627	$ 549,267	$ 119,801	$ 567,497	$ 1,060	$ 150,127	$ 39,343	RJA-5
10	Economic Carryin Charge Rate			15.56%	15.56%	15.56%	15.56%	15.56%	15.56%	15.56%	15.56%	
11	Annual Carrying Charge per customer	$		$ 177.51	$ 230.27	$ 577.38						
12	Class Annual Carrying Charge	$	$ 13,625,113	$ 11,093,183	$ 2,309,911	$ 85,452	$ 18,638	$ 88,288	$ 165	$ 23,356	$ 6,121	
13	**Meters & Regulators**											
14	Average Cost	$		$ 304	$ 969	$ 4,551						RJA-2
15	Total Investment	$	$ 32,718,449	$ 18,977,145	$ 9,724,203	$ 673,594	$ 345,837	$ 2,331,813	$ 207,315	$ 298,833	$ 159,709	RJA-5
16	Economic Carryin Charge Rate			16.76%	16.76%	16.76%	16.76%	16.76%	16.76%	16.76%	16.76%	
17	Annual Carrying Charge per customer	$		$ 50.91	$ 162.51	$ 763.01						
18	Class Annual Carrying Charge	$	$ 5,485,121	$ 3,181,445	$ 1,630,225	$ 112,925	$ 57,978	$ 390,919	$ 34,756	$ 50,098	$ 26,775	
19	**Mains Investment**											
20	Customer Mains Investment											
21	Typical Size	in.		2	2	2						
22	Material			Plastic	Plastic	Steel						
23	Avg. Mains extension per customer	ft		83.54	166.64	899.14						RJA-3C&3D
24	Average cost per ft	$/ft		$ 9.12	$ 9.12	$ 52.18						RJA-3B
25	Customer mains investment per customer	$		$ 762	$ 1,520	$ 46,919						
26	Customer Mains Investment by Class		$ 83,939,672	$ 47,628,042	$ 15,249,668	$ 6,944,062	$ 1,040,738	$ 6,812,581	$ 4,602,006	$ 1,137,667	$ 524,907	RJA-5
27	Long-Run System Replacement Investment											
28	Mains System Replacement Cost	$	$ 388,495,237									RJA-3A
29	Less: Customer Mains Investment	$	$ (83,939,672)									
30	Long-Run System Replacement Investment	$	$ 304,555,565									
31	Capacity	%	78%									
32	Investment per Peak Day Capacity	$/Dth-Day	$ 2,421									
33	Investment by Class	$	$ 236,902,113	$ 119,457,091	$ 82,726,528	$ 7,718,207	$ 2,265,701	$ 24,734,585	$ -	$ -	$ -	
34	Investment per customer	$		$ 1,912	$ 8,247	$ 52,150	$ 125,872	$ 772,956	$ -	$ -	$ -	

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Plant Carrying Costs

Line	Description	Unit	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Transportation non-core	902-2 Special Contract non-core	170 Interruptible core	9xx Special Contracts non-core	Source
35	Commodity	%	22%									
36	System Replacement Investment per Dth	$/Dth	$ 6.10									
37	Investment by Class	$	$ 67,653,451	$ 26,217,386	$ 18,475,528	$ 1,243,009	$ 994,316	$ 19,247,882		$ 1,475,330		
38	Investment per customer	$		$ 420	$ 1,842	$ 8,399	$ 55,240	$ 601,496	$ -	$ 368,832	$ -	
39	Total mains investment by class	$	$ 388,495,237	$ 193,302,520	$ 116,451,724	$ 15,905,278	$ 4,300,755	$ 50,795,049	$ 4,602,006	$ 2,612,997	$ 524,907	
40	Economic Carryin Charge Rate			14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	14.52%	
41	Class Annual Carrying Charge	$	$ 56,396,352	$ 28,060,980	$ 16,904,847	$ 2,308,908	$ 624,324	$ 7,373,721	$ 668,055	$ 379,319	$ 76,199	
42	**Total Carrying Costs**		**$ 75,506,587**	**$ 42,335,608**	**$ 20,844,983**	**$ 2,507,285**	**$ 700,940**	**$ 7,852,928**	**$ 702,976**	**$ 452,773**	**$ 109,094**	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 604

Incremental O&M Costs

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
O&M Costs

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Transportation non-core	902-2 Special Contract non-core	170 Interruptible core	9xx Special Contracts non-core	Source
1	**Billing Determinants**										
2	Peak Day Forecast	97,866	49,348	34,175	3,188	936	10,218	-	-	-	
3	Customer Count	72,730	62,493	10,031	148	18	32	1	4	3	
4	Throughput	30,693,226	4,297,744	3,028,642	203,763	162,996	3,155,252	16,953,916	241,847	2,649,066	
5	Sales	7,934,992	4,297,744	3,028,642	203,763	162,996			241,847		
6	Peak & Average	100%	32.2%	22.4%	2.0%	0.7%	10.4%	27.6%	0.4%	4.3%	
7	Customer Count (Small Customers)	72,672	62,493	10,031	148						
8	Customer Count (Large Customers)	58				18	32	1	4	3	
9	Volumes (Core)		4,297,744	3,028,642	203,763	162,996			241,847		
10	Volumes (Non-core)						3,155,252	16,953,916		2,649,066	
11	**Gas Planning**										
12	Core	$ 65,594	$ 36,617	$ 25,455	$ 2,229	$ 845			$ 448		RJA-4A
13	Non-core	$ 18,358					$ 4,497	$ 11,988		$ 1,873	RJA-4A
14	Total Core + Non-core	$ 83,952	$ 36,617	$ 25,455	$ 2,229	$ 845	$ 4,497	$ 11,988	$ 448	$ 1,873	
15	Cost per customer		$ 0.59	$ 2.54	$ 15.06	$ 46.97	$ 140.53	$ 11,988.08	$ 111.96	$ 624.38	
16	**Gas Supply**										
17	Core	$ 31,921	$ 17,289	$ 12,184	$ 820	$ 656			$ 973		RJA-4A
18	Non-core	$ 8,752					$ 2,144	$ 5,715		$ 893	RJA-4A
19	Total Core + Non-core	$ 40,673	$ 17,289	$ 12,184	$ 820	$ 656	$ 2,144	$ 5,715	$ 973	$ 893	
20	Cost per Cust		$ 0.28	$ 1.21	$ 5.54	$ 36.43	$ 67.00	$ 5,715.18	$ 243.23	$ 297.67	
21	**Gas Control**										
22	Core	$ 53,271	$ 28,852	$ 20,332	$ 1,368	$ 1,094			$ 1,624		RJA-4A
23	Non-core	$ 24,355					$ 11,036	$ 11,353		$ 1,966	RJA-4A
24	Total Core + Non-core	$ 77,626	$ 28,852	$ 20,332	$ 1,368	$ 1,094	$ 11,036	$ 11,353	$ 1,624	$ 1,966	
25	Cost per Cust		$ 0.46	$ 2.03	$ 9.24	$ 60.79	$ 344.87	$ 11,353.07	$ 405.90	$ 655.39	
26	**Total Gas Supply O&M**	**$ 202,251**	**$ 82,758**	**$ 57,971**	**$ 4,417**	**$ 2,595**	**$ 17,677**	**$ 29,056**	**$ 3,044**	**$ 4,732**	

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
O&M Costs

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Transportation non-core	902-2 Special Contract non-core	170 Interruptible core	9xx Special Contracts non-core	Source
27	**Meter Reading**										
28	Meter Reading Expense (Res, Small Comm.)	$ 254,168	$ 218,566	$ 35,085	$ 518	$ -	$ -	$ -	$ -	$ -	RJA-4B
29	Meter Reading Expense (Industrial)	$ 6,702	$ -	$ -	$ -	$ 2,080	$ 3,698	$ 116	$ 462	$ 347	RJA-4B
30	Meter Reading Expense	$ 260,870	$ 218,566	$ 35,085	$ 518	$ 2,080	$ 3,698	$ 116	$ 462	$ 347	
31	Cost per customer		$ 3.50	$ 3.50	$ 3.50	$ 115.55	$ 115.55	$ 115.55	$ 115.55	$ 115.55	
32	**Customer Acoount records and collection**										
33	Expense	$ 1,310,353	$ 1,126,528	$ 180,832	$ 2,668	$ 324					RJA-4C
34	Expense - Manual Billing	$ 8,186					$ 6,549	$ 205	$ 819	$ 614	RJA-4C
35	Cost per customer		$ 18.03	$ 18.03	$ 18.03	$ 18.03	$ 204.65	$ 204.65	$ 204.65	$ 204.65	
36	**Billing Postage & Printing**										
37	Expense	$ 367,765	$ 315,999	$ 50,725	$ 748	$ 91	$ 162	$ 5	$ 20	$ 15	RJA-4D
38	Cost per customer		$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.06	$ 5.06	
39	**Uncollectible**										
40	COMMERCIAL	$ 35,720		$ 35,720							RJA-4E
41	INDUSTRIAL	$ -			$ -						RJA-4E
42	RESIDENTIAL	$ 283,335	$ 283,335								RJA-4E
43	Total OR	$ 319,056	$ 283,335	$ 35,720	$ -	$ -	$ -	$ -	$ -	$ -	
44	Cost per customer		$ 4.53	$ 3.56	$ -	$ -	$ -	$ -	$ -	$ -	
45	**Total Customer O&M**	**$ 2,266,229**	**$ 1,944,429**	**$ 302,361**	**$ 3,934**	**$ 2,495**	**$ 10,408**	**$ 325**	**$ 1,301**	**$ 976**	
46	Gas Control O&M Allocation to Non-core						45.3%	46.6%		8.1%	RJA-4F

CNGC/605
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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 605

Summary of Revenue by Rate Class

Customer Class	Revenues			
	Pro Forma	Proposed	$ Difference	% Difference
Residential - 101				
Basic Service Charge	$ 2,999,652	$ 3,749,565	$ 749,913	25%
Delivery Charge	15,646,797	16,681,693	1,034,897	7%
Rounding Difference	-	198	198	
Total 101 Revenue	$ 18,646,449	$ 20,431,456	$ 1,785,008	10%
Commercial - 104				
Basic Service Charge	$ 481,508	$ 1,203,770	$ 722,262	150%
Delivery Charge	7,954,124	7,231,792	(722,331)	-9%
Rounding Difference	-	69	69	
Total 104 Revenue	$ 8,435,632	$ 8,435,632	$ -	0%
Industrial - 105				
Basic Service Charge	$ 21,312	$ 53,280	$ 31,968	150%
Delivery Charge	418,876	482,307	63,431	15%
Rounding Difference	-	(7)	(7)	
Total 105 Revenue	$ 440,188	$ 535,581	$ 95,393	22%
Large Volume - 111				
Basic Service Charge	$ -	$ 27,000	$ 27,000	n/a
Delivery Charge	270,442	243,450	(26,992)	-10%
Rounding Difference	-	(8)	(8)	
Total 111 Revenue	$ 270,442	$ 270,442	$ -	0%
General Distribution - 163				
Basic Service Charge	$ 192,000	$ 240,000	$ 48,000	25%
Demand Charge	$ -	$ 167,472	$ 167,472	n/a
Delivery Charge	1,974,656	2,189,528	214,872	11%
Rounding Difference	-	63	63	
Total 163 Revenue	$ 2,166,656	$ 2,597,063	$ 430,407	20%
Special Contract 902-2				
Basic Service Charge	$ 6,000	$ 7,500	$ 1,500	25%
Demand Charge	$ 1,085,999	$ 718,488	$ (367,511)	-34%
Delivery Charge	265,481	631,531	366,050	138%
Rounding Difference	-	(39)	(39)	
Total 902-2 Revenue	$ 1,357,481	$ 1,357,481	$ -	0%
Interruptible - 170				
Basic Service Charge	$ -	$ 14,400	$ 14,400	n/a
Delivery Charge	297,689	283,299	(14,390)	-5%
Rounding Difference	-	(10)	(10)	
Total 170 Revenue	$ 297,689	$ 297,689	$ -	0%
Special Contracts - 9xx				
Basic Service Charge	$ 18,000	$ 18,000	$ -	0%
Delivery Charge	274,134	274,134	-	0%
Demand Charge	82,800	82,800	-	0%
Rounding Difference	-	-	-	
Total 9xx Revenue	$ 374,934	$ 374,934	$ -	0%
TOTAL	**$ 31,989,470**	**$ 34,300,278**	**$ 2,310,808**	

CNGC/606
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 606

Analysis of Revenue by Detailed Rate Schedule

Cascade Natural Gas Corporation
Oregon Jurisdiction
Test Year Ended December 31, 2017

CNG/606
Amen/1
Analysis of Revenue by Detailed Rate Schedule

Customer Class	Pro Forma Test Year Revenues			Proposed Revenues		Difference	
	Billing Units*	Present Rate	Revenue	Proposed Rates	Revenue	$ Amount	% Amount
Residential - 101							
Basic Service Charge	749,913	$4.00	$ 2,999,652	$5.00	$ 3,749,565	$ 749,913	25%
Delivery Charge	42,977,440	$0.36407	$ 15,646,797	$0.38815	$ 16,681,693	$ 1,034,897	7%
Rounding Difference					$ 198	$ 198	
Total 101 Revenue			**$ 18,646,449**		**$ 20,431,456**	**$ 1,785,008**	10%
Commercial - 104							
Basic Service Charge	120,377	$4.00	$ 481,508	$10.00	$ 1,203,770	$ 722,262	150%
Delivery Charge	30,286,424	$0.26263	$ 7,954,124	$0.23878	$ 7,231,792	$ (722,331)	-9%
Rounding Difference					$ 69	$ 69	
Total 104 Revenue			**$ 8,435,632**		**$ 8,435,632**	**$ 0**	0%
Industrial - 105							
Basic Service Charge	1,776	$12.00	$ 21,312	$30.00	$ 53,280	$ 31,968	150%
Delivery Charge	2,037,630	$0.20557	$ 418,876	$0.23670	$ 482,307	$ 63,431	15%
Rounding Difference					$ (7)	$ (7)	
Total 105 Revenue			**$ 440,188**		**$ 535,581**	**$ 95,393**	22%
Large Volume - 111							
Basic Service Charge	216	$0.00	$ -	$125.00	$ 27,000	$ 27,000	
Delivery Charge	1,629,956	$0.16592	$ 270,442	$0.14936	$ 243,450	$ (26,992)	-10%
Rounding Difference					$ (8)	$ (8)	
Total 111 Revenue			**$ 270,442**		**$ 270,442**	**$ (0)**	0%
General Distribution - 163							
Basic Service Charge	384	$500.00	$ 192,000	$625.00	$ 240,000	$ 48,000	25%
Contract Demand Charge - proposed	1,674,720			$0.10000	$ 167,472	$ 167,472	n/a
Delivery Charge - first 10,000 therms	3,379,835	$0.12402	$ 419,167	$0.137520	$ 464,795	$ 45,628	11%
Delivery Charge - next 10,000 therms	2,565,618	$0.11188	$ 287,041	$0.124060	$ 318,291	$ 31,249	11%
Delivery Charge - next 30,000 therms	4,423,532	$0.10512	$ 465,002	$0.116560	$ 515,607	$ 50,605	11%
Delivery Charge - next 50,000 therms	4,107,177	$0.06456	$ 265,159	$0.071590	$ 294,033	$ 28,873	11%
Delivery Charge - next 400,000 therms	15,697,119	$0.03275	$ 514,081	$0.036310	$ 569,962	$ 55,882	11%
Delivery Charge - next 500,000 therms	1,379,242	$0.01755	$ 24,206	$0.019460	$ 26,840	$ 2,634	11%
Delivery Charge - over 1,000,000 therms	-	$0.01755		$0.001423	$ -	$ -	
Rounding Difference					$ 63	$ 63	
Total 163 Revenue			**$ 2,166,656**		**$ 2,597,063**	**$ 430,407**	20%
Special Contract 902-2							
Basic Service Charge	12	$500.00	$ 6,000	$625.00	$ 7,500	$ 1,500	25%
Contract Demand Charge - existing	10,800,000	$0.1005555	$ 1,085,999				
Contract Demand Charge - proposed	7,184,880			$0.10000	$ 718,488	$ (367,511)	-34%
Delivery Charge - first 10,000 therms	120,000	$0.0015659	$ 188	$0.137520	$ 16,502	$ 16,314	8682%
Delivery Charge - next 10,000 therms	120,000	$0.0015659	$ 188	$0.124060	$ 14,887	$ 14,699	7823%
Delivery Charge - next 30,000 therms	360,000	$0.0015659	$ 564	$0.116560	$ 41,962	$ 41,398	7344%
Delivery Charge - next 50,000 therms	600,000	$0.0015659	$ 940	$0.071590	$ 42,954	$ 42,014	4472%
Delivery Charge - next 400,000 therms	4,800,000	$0.0015659	$ 7,516	$0.036310	$ 174,288	$ 166,772	2219%
Delivery Charge - next 500,000 therms	6,000,000	$0.0015659	$ 9,395	$0.019460	$ 116,760	$ 107,365	1143%
Delivery Charge - over 1,000,000 therms	157,539,157	$0.0015659	$ 246,691	$0.001423	$ 224,178	$ (22,512)	-9%
Rounding Difference					$ (39)	$ (39)	
Total Special Contract 902-2 Revenue			**$ 1,357,481**		**$ 1,357,481**	**$ -**	0%
Interruptible - 170							
Basic Service Charge	48	$0.00	$ -	$300.00	$ 14,400	$ 14,400	n/a
Delivery Charge	2,418,468	$0.12309	$ 297,689	$0.11714	$ 283,299	$ (14,390)	-5%
Rounding Difference					$ (10)	$ (10)	
Total 170 Revenue			**$ 297,689**		**$ 297,689**	**$ 0**	0%

*** Delivery Charge units are in therms**

CNGC/607
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 607

Residential Impact by Month

Residential - 101

Line No.	(a)	(b)	(c)	(d)	(e)	(f)
			Present Rates	Proposed Rates		
1	Basic Service Charge		$4.00	$5.00		
2	Delivery Charge		$0.36407	$0.38815		
3	PGA Rate		$0.40660	$0.40660		

Line No.	Month	Average therms per Customer	Revenue at Present Rates	Revenue at Proposed Rates	Monthly Bill Change Amount	Monthly Bill Change Percent
4	January	112	$ 90.32	$ 94.01	$ 3.70	4.09%
5	February	90	$ 73.36	$ 76.53	$ 3.17	4.32%
6	March	77	$ 63.34	$ 66.20	$ 2.85	4.51%
7	April	53	$ 44.85	$ 47.12	$ 2.28	5.08%
8	May	34	$ 30.20	$ 32.02	$ 1.82	6.02%
9	June	21	$ 20.18	$ 21.69	$ 1.51	7.46%
10	July	16	$ 16.33	$ 17.72	$ 1.39	8.48%
11	August	16	$ 16.33	$ 17.72	$ 1.39	8.48%
12	September	21	$ 20.18	$ 21.69	$ 1.51	7.46%
13	October	47	$ 40.22	$ 42.35	$ 2.13	5.30%
14	November	83	$ 67.97	$ 70.96	$ 3.00	4.41%
15	December	118	$ 94.94	$ 98.78	$ 3.84	4.05%
16	Total	688	$ 578.22	$ 606.79	$ 28.57	
17	Monthly Average		$ 48.19	$ 50.57	$ 2.38	4.94%

CNGC/608
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 608

Impact of Recommended Rate Changes

Residential - 101

Line No.	(a)	(b)	(c)	(d)	(e)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$4.00	$5.00		
2	Delivery Charge	$0.36407	$0.38815		
3	PGA Rate	$0.40660	$0.40660		

	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$4.00	$5.00	$1.00	25.00%
5	25	$23.27	$24.87	$1.60	6.89%
6	30	$27.12	$28.84	$1.72	6.35%
7	35	$30.97	$32.82	$1.84	5.95%
8	40	$34.83	$36.79	$1.96	5.64%
9	45	$38.68	$40.76	$2.08	5.39%
10	50	$42.53	$44.74	$2.20	5.18%
11	60	$50.24	$52.69	$2.44	4.87%
12	70	$57.95	$60.63	$2.69	4.63%
13	80	$65.65	$68.58	$2.93	4.46%
14	90	$73.36	$76.53	$3.17	4.32%
15	100	$81.07	$84.48	$3.41	4.20%
16	110	$88.77	$92.42	$3.65	4.11%
17	120	$96.48	$100.37	$3.89	4.03%
18	130	$104.19	$108.32	$4.13	3.96%
19	140	$111.89	$116.27	$4.37	3.91%
20	150	$119.60	$124.21	$4.61	3.86%
21	160	$127.31	$132.16	$4.85	3.81%
22	170	$135.01	$140.11	$5.09	3.77%
23	180	$142.72	$148.06	$5.33	3.74%
24	190	$150.43	$156.00	$5.58	3.71%
25	200	$158.13	$163.95	$5.82	3.68%
26	210	$165.84	$171.90	$6.06	3.65%
27	220	$173.55	$179.85	$6.30	3.63%
28	230	$181.25	$187.79	$6.54	3.61%
29	240	$188.96	$195.74	$6.78	3.59%
30	250	$196.67	$203.69	$7.02	3.57%

Commercial - 104

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$4.00	$10.00		
2	Delivery Charge	$0.26263	$0.23878		
3	PGA Rate	$0.40660	$0.40660		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$4.00	$10.00	$6.00	150.00%
5	50	$37.46	$42.27	$4.81	12.83%
6	60	$44.15	$48.72	$4.57	10.35%
7	70	$50.85	$55.18	$4.33	8.52%
8	80	$57.54	$61.63	$4.09	7.11%
9	90	$64.23	$68.08	$3.85	6.00%
10	100	$70.92	$74.54	$3.62	5.10%
11	110	$77.62	$80.99	$3.38	4.35%
12	120	$84.31	$87.45	$3.14	3.72%
13	130	$91.00	$93.90	$2.90	3.19%
14	140	$97.69	$100.35	$2.66	2.72%
15	150	$104.38	$106.81	$2.42	2.32%
16	160	$111.08	$113.26	$2.18	1.97%
17	170	$117.77	$119.71	$1.95	1.65%
18	180	$124.46	$126.17	$1.71	1.37%
19	190	$131.15	$132.62	$1.47	1.12%
20	200	$137.85	$139.08	$1.23	0.89%
21	250	$171.31	$171.35	$0.04	0.02%
22	300	$204.77	$203.61	-$1.15	-0.56%
23	350	$238.23	$235.88	-$2.35	-0.99%
24	400	$271.69	$268.15	-$3.54	-1.30%
25	450	$305.15	$300.42	-$4.73	-1.55%
26	500	$338.62	$332.69	-$5.92	-1.75%
27	600	$405.54	$397.23	-$8.31	-2.05%
28	700	$472.46	$461.77	-$10.70	-2.26%
29	800	$539.38	$526.30	-$13.08	-2.42%
30	1,000	$673.23	$655.38	-$17.85	-2.65%
31	1,250	$840.54	$816.73	-$23.81	-2.83%
32	1,500	$1,007.85	$978.07	-$29.78	-2.95%
33	1,750	$1,175.15	$1,139.42	-$35.74	-3.04%
34	2,000	$1,342.46	$1,300.76	-$41.70	-3.11%
35	2,500	$1,677.08	$1,623.45	-$53.62	-3.20%
36	3,000	$2,011.69	$1,946.14	-$65.55	-3.26%
37	3,500	$2,346.31	$2,268.83	-$77.47	-3.30%
38	4,000	$2,680.92	$2,591.52	-$89.40	-3.33%

Industrial - 105

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$12.00	$30.00		
2	Delivery Charge	$0.20557	$0.23670		
3	PGA Rate	$0.40660	$0.40660		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$12.00	$30.00	$18.00	150.00%
5	100	$73.22	$94.33	$21.11	28.84%
6	200	$134.43	$158.66	$24.23	18.02%
7	300	$195.65	$222.99	$27.34	13.97%
8	400	$256.87	$287.32	$30.45	11.86%
9	500	$318.09	$351.65	$33.57	10.55%
10	600	$379.30	$415.98	$36.68	9.67%
11	700	$440.52	$480.31	$39.79	9.03%
12	800	$501.74	$544.64	$42.90	8.55%
13	900	$562.95	$608.97	$46.02	8.17%
14	1,000	$624.17	$673.30	$49.13	7.87%
15	1,100	$685.39	$737.63	$52.24	7.62%
16	1,200	$746.60	$801.96	$55.36	7.41%
17	1,300	$807.82	$866.29	$58.47	7.24%
18	1,400	$869.04	$930.62	$61.58	7.09%
19	1,500	$930.26	$994.95	$64.69	6.95%
20	2,000	$1,236.34	$1,316.60	$80.26	6.49%
21	2,500	$1,542.43	$1,638.25	$95.83	6.21%
22	3,000	$1,848.51	$1,959.90	$111.39	6.03%
23	3,500	$2,154.60	$2,281.55	$126.96	5.89%
24	4,000	$2,460.68	$2,603.20	$142.52	5.79%
25	5,000	$3,072.85	$3,246.50	$173.65	5.65%
26	6,000	$3,685.02	$3,889.80	$204.78	5.56%
27	7,000	$4,297.19	$4,533.10	$235.91	5.49%
28	8,000	$4,909.36	$5,176.40	$267.04	5.44%
29	9,000	$5,521.53	$5,819.70	$298.17	5.40%
30	10,000	$6,133.70	$6,463.00	$329.30	5.37%
31	12,500	$7,664.13	$8,071.25	$407.13	5.31%
32	15,000	$9,194.55	$9,679.50	$484.95	5.27%
33	17,500	$10,724.98	$11,287.75	$562.78	5.25%
34	20,000	$12,255.40	$12,896.00	$640.60	5.23%
35	25,000	$15,316.25	$16,112.50	$796.25	5.20%
36	30,000	$18,377.10	$19,329.00	$951.90	5.18%
37	35,000	$21,437.95	$22,545.50	$1,107.55	5.17%
38	40,000	$24,498.80	$25,762.00	$1,263.20	5.16%
39	45,000	$27,559.65	$28,978.50	$1,418.85	5.15%
40	50,000	$30,620.50	$32,195.00	$1,574.50	5.14%
41	60,000	$36,742.20	$38,628.00	$1,885.80	5.13%
42	70,000	$42,863.90	$45,061.00	$2,197.10	5.13%
43	80,000	$48,985.60	$51,494.00	$2,508.40	5.12%
44	90,000	$55,107.30	$57,927.00	$2,819.70	5.12%
45	100,000	$61,229.00	$64,360.00	$3,131.00	5.11%

Large Volume - 111

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$0.00	$125.00		
2	Delivery Charge	$0.16592	$0.14936		
3	PGA Rate	$0.40660	$0.40660		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$0.00	$125.00	$125.00	
5	100	$57.25	$180.60	$123.34	215.44%
6	200	$114.50	$236.19	$121.69	106.27%
7	300	$171.76	$291.79	$120.03	69.89%
8	400	$229.01	$347.38	$118.38	51.69%
9	500	$286.26	$402.98	$116.72	40.77%
10	600	$343.51	$458.58	$115.06	33.50%
11	700	$400.76	$514.17	$113.41	28.30%
12	800	$458.02	$569.77	$111.75	24.40%
13	900	$515.27	$625.36	$110.10	21.37%
14	1,000	$572.52	$680.96	$108.44	18.94%
15	1,100	$629.77	$736.56	$106.78	16.96%
16	1,200	$687.02	$792.15	$105.13	15.30%
17	1,300	$744.28	$847.75	$103.47	13.90%
18	1,400	$801.53	$903.34	$101.82	12.70%
19	1,500	$858.78	$958.94	$100.16	11.66%
20	2,000	$1,145.04	$1,236.92	$91.88	8.02%
21	2,500	$1,431.30	$1,514.90	$83.60	5.84%
22	3,000	$1,717.56	$1,792.88	$75.32	4.39%
23	3,500	$2,003.82	$2,070.86	$67.04	3.35%
24	4,000	$2,290.08	$2,348.84	$58.76	2.57%
25	5,000	$2,862.60	$2,904.80	$42.20	1.47%
26	6,000	$3,435.12	$3,460.76	$25.64	0.75%
27	7,000	$4,007.64	$4,016.72	$9.08	0.23%
28	8,000	$4,580.16	$4,572.68	-$7.48	-0.16%
29	9,000	$5,152.68	$5,128.64	-$24.04	-0.47%
30	10,000	$5,725.20	$5,684.60	-$40.60	-0.71%
31	12,500	$7,156.50	$7,074.50	-$82.00	-1.15%
32	15,000	$8,587.80	$8,464.40	-$123.40	-1.44%
33	17,500	$10,019.10	$9,854.30	-$164.80	-1.64%
34	20,000	$11,450.40	$11,244.20	-$206.20	-1.80%
35	25,000	$14,313.00	$14,024.00	-$289.00	-2.02%
36	30,000	$17,175.60	$16,803.80	-$371.80	-2.16%
37	35,000	$20,038.20	$19,583.60	-$454.60	-2.27%
38	40,000	$22,900.80	$22,363.40	-$537.40	-2.35%
39	45,000	$25,763.40	$25,143.20	-$620.20	-2.41%
40	50,000	$28,626.00	$27,923.00	-$703.00	-2.46%
41	60,000	$34,351.20	$33,482.60	-$868.60	-2.53%
42	70,000	$40,076.40	$39,042.20	-$1,034.20	-2.58%
43	80,000	$45,801.60	$44,601.80	-$1,199.80	-2.62%
44	90,000	$51,526.80	$50,161.40	-$1,365.40	-2.65%
45	100,000	$57,252.00	$55,721.00	-$1,531.00	-2.67%

Interruptible - 170

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$0.00	$300.00		
2	Delivery Charge	$0.12309	$0.11714		
3	PGA Rate	$0.40660	$0.40660		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$0.00	$300.00	$300.00	
5	500	$264.85	$561.87	$297.03	112.15%
6	1,000	$529.69	$823.74	$294.05	55.51%
7	1,500	$794.54	$1,085.61	$291.08	36.63%
8	2,000	$1,059.38	$1,347.48	$288.10	27.20%
9	2,500	$1,324.23	$1,609.35	$285.13	21.53%
10	3,000	$1,589.07	$1,871.22	$282.15	17.76%
11	3,500	$1,853.92	$2,133.09	$279.18	15.06%
12	4,000	$2,118.76	$2,394.96	$276.20	13.04%
13	4,500	$2,383.61	$2,656.83	$273.23	11.46%
14	5,000	$2,648.45	$2,918.70	$270.25	10.20%
15	6,000	$3,178.14	$3,442.44	$264.30	8.32%
16	7,000	$3,707.83	$3,966.18	$258.35	6.97%
17	8,000	$4,237.52	$4,489.92	$252.40	5.96%
18	9,000	$4,767.21	$5,013.66	$246.45	5.17%
19	10,000	$5,296.90	$5,537.40	$240.50	4.54%
20	11,000	$5,826.59	$6,061.14	$234.55	4.03%
21	12,000	$6,356.28	$6,584.88	$228.60	3.60%
22	13,000	$6,885.97	$7,108.62	$222.65	3.23%
23	14,000	$7,415.66	$7,632.36	$216.70	2.92%
24	15,000	$7,945.35	$8,156.10	$210.75	2.65%
25	17,500	$9,269.58	$9,465.45	$195.87	2.11%
26	20,000	$10,593.80	$10,774.80	$181.00	1.71%
27	22,500	$11,918.03	$12,084.15	$166.13	1.39%
28	25,000	$13,242.25	$13,393.50	$151.25	1.14%
29	30,000	$15,890.70	$16,012.20	$121.50	0.76%
30	35,000	$18,539.15	$18,630.90	$91.75	0.49%
31	40,000	$21,187.60	$21,249.60	$62.00	0.29%
32	45,000	$23,836.05	$23,868.30	$32.25	0.14%
33	50,000	$26,484.50	$26,487.00	$2.50	0.01%
34	60,000	$31,781.40	$31,724.40	-$57.00	-0.18%
35	70,000	$37,078.30	$36,961.80	-$116.50	-0.31%
36	80,000	$42,375.20	$42,199.20	-$176.00	-0.42%
37	90,000	$47,672.10	$47,436.60	-$235.50	-0.49%
38	100,000	$52,969.00	$52,674.00	-$295.00	-0.56%
39	125,000	$66,211.25	$65,767.50	-$443.75	-0.67%
40	150,000	$79,453.50	$78,861.00	-$592.50	-0.75%
41	175,000	$92,695.75	$91,954.50	-$741.25	-0.80%
42	200,000	$105,938.00	$105,048.00	-$890.00	-0.84%
43	225,000	$119,180.25	$118,141.50	-$1,038.75	-0.87%
44	250,000	$132,422.50	$131,235.00	-$1,187.50	-0.90%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 347

RONALD J. AMEN
Exhibit No. 609

Ronald J. Amen Statement of Qualifications

Ronald J. Amen

Mr. Amen has over 38 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing and sales, and systems administration. He has advised both investor-owned and public gas, electric and water utility clients in the following areas: regulatory policy, strategy and analysis; cost of service studies (embedded and marginal cost analyses); rate design and pricing issues, including time-of-use rates, revenue decoupling, weather normalization and other cost tracking mechanisms; resource strategy, planning and financial analysis; and business process design, evaluation and organizational structures. Mr. Amen has provided expert testimony in numerous state and provincial regulatory agencies, and the Federal Energy Regulatory Commission. Prior to joining Black & Veatch, Mr. Amen's consulting experience included Vice President of Concentric Energy Advisors, Inc. and Director with Navigant Consulting, Inc. His prior utility experience includes Manager of Federal Regulatory Affairs at Puget Sound Energy, Inc., Director of Rates at Washington Natural Gas Company, Regional Director - Operations and Director – Rates for Indiana Energy (now Vectren), and management positions in Information Systems and Distribution Operations at Ohio Valley Gas Corporation.

DIRECTOR

Specialization:
Financial analysis, regulatory support, strategy, operations, litigation support

Office Location
Redmond, Washington

Education
- B.S., Business Administration (Finance and Economics), College of Business Administration, University of Nebraska, 1978

Professional Associations
- American Gas Association
- Southern Gas Association

Year Career Started
1978

Year Started with B&V
2013

PROJECT EXPERIENCE

REGULATORY POLICY, STRATEGY AND ANALYSIS

CPS Energy (2017 – Present)

Provided an overall review of the client's Strategic Roadmap to prioritize its multi-year regulatory initiatives. (e.g., changes in product and service offerings, restructuring of current rate classes, introduction of new rate structures, rate levels, and tariff provisions). Current pricing processes and platforms assessed to identify recommended enhancements to enable the development and implementation of dynamic pricing concepts. Assisted client with preparation of next rate case (e.g., costing and pricing analyses, load forecasting, internal communications, and stakeholder engagement).

FortisBC Energy, Inc. (2016 – 2017)

Performed an overall review of the client's Transportation Service Model. Analyzed the client's various midstream transportation and storage capacity resources used in providing balancing of transportation customers' loads. Review included the physical diversity, functionality and flexibility provided by the various capacity resources, and the cost impact caused by transportation customers' imbalance levels. Conducted an industry-wide benchmarking study of current industry-wide best practices, by regulatory jurisdiction, related to transportation balancing tariff provisions.

McDowell Rackner & Gibson Law Firm (2015 – 2016)

Provided due diligence services to the law firm in connection with a state utility commission investigation into the law firm client's gas storage and optimization activities. Provided an independent opinion as to the likely outcome of the Commission's ongoing investigation.

Gulfport Energy Corporation (2016)

Provided regulatory analysis and support to Gulfport Energy Corporation in the ANR Pipeline Company Natural Gas Act §4 rate proceeding before the Federal Energy Regulatory Commission (FERC). Analyzed as-filed cost of service and rate design to identify key cost of service, cost allocation, rate design and service related/tariff issues. Developed an integrated cost of service and rate design model to prepare studies on client issues. Prepared best/worst case litigation outcomes, discovery and evaluations of discovery of other parties. Analyzed FERC staff top sheets and settlement offers; and assisted in the preparation of settlement positions.

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009 – 2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Confidential Energy Company (2007)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Public Service Electric & Gas (2004)

Provided management with an evaluation of its line extension practices for both its gas and electric services and an earnings impact assessment using a proprietary evaluation model. Conducted a workshop for management on the results of the evaluation and recommendations for consideration in the areas of revenue enhancements, modification of internal policies and procedures, and construction cost control areas.

Washington Gas Light (2004)

Provided management with an evaluation of the policies, procedures and tools presently used in its new customer addition process, an assessment of the impact of new customer growth on net operating income, and regulatory solutions to accelerate recovery of new customer costs that best meet the regulatory requirements of its three state jurisdictions.

Confidential Energy Company (2003)

Performed due diligence on behalf of a confidential energy company client related to the acquisition of a U.S. interstate pipeline, involving a market assessment related to its customer contracts and their prospective alternatives.

Terasen Gas (now FortisBC) (2002 – 2003)

Engaged to assist with the development of a gas transmission asset ownership strategy. The project included researching examples from other jurisdictions in North America for transmission ownership structures, the supporting rationale and the resulting regulatory treatment.

Chesapeake Utilities (2001 – 2002)

Provided expert witness testimony on the subject of new area expansion programs in the United States for the client's general rate case proceeding in Delaware. As part of a negotiated settlement of the case, the client was permitted to establish a new area expansion pilot program.

Puget Sound Energy (1997, 2001)

Redesigned gas line extension policy based on financial investment criteria, standardized construction costs, and revenue contributions derived from the client's residential end-use data (building type/size/vintage, appliance type, etc.). Introduced a new customer rate option for customers whose facilities extensions did not meet the target rate of return requirement, which significantly reduced earnings attrition caused by rapid customer growth. In a later general rate proceeding, testimony support was provided regarding the modifications and revisions to the facilities extension program.

RESOURCE PLANNING, STRATEGY AND FINANCIAL ANALYSIS

Fortis BC Energy, Inc. (2011)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Avista Utilities (2005)

As part of a review of a gas procurement strategy and hedging analytics, provided gas local distribution company (LDC) case studies for gas procurement and risk management practices, including identification of risk management best practices across the industry.

Puget Sound Energy (2003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts.

Puget Sound Energy (2002 – 2003)

Engaged as a member of a consulting team serving as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for and evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition in a subsequent power cost rate proceeding.

Central Illinois Light Company (Ameren Utilities) (2002 – 2003)

Provided an evaluation of the functions provided by the utility's underground storage facilities for the purpose of assigning cost responsibility to the various customer groups, which had been challenged by parties in the company's general rate proceeding.

Confidential European Electric Utility (1999)

Provided strategy and analysis support, including a review of the natural gas value chain in the United States, as part of an overall project scope focusing on the evaluation of retail multi-energy strategies for the client.

Austin Energy (1997 – 1998)

Engaged as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process.

COST ALLOCATION, PRICING ISSUES AND RATE DESIGN

Florida Public Utilities (Chesapeake Utilities) (2017 – 2018)

Provided a rate stratification study of the utility's commercial and industrial customer classes to facilitate the reconfiguration of the classes by size of service facilities, annual volume, and load factor. Reviewed the cost allocation bases and recommended alternatives for recovery of capital investments related to the utility's Gas Reliability Investment Program (GRIP).

BC Hydro (2016)

Provided research and analysis of the line extension policies of a select group of peer utilities in Canada with similar regulatory regimes as well as U.S. utilities based on their geographic relationship to the client. Conducted interviews with peer utilities to gather comparative information regarding their line extension policies and related internal procedures. Performed a comparative analysis of the various line extension policies from the selected peer group.

Tacoma Power (2016 – Present)

Provided cost of service and rate design support for the electric utility's general rate case filings, including support for recovery of fixed costs through fixed charges and impacts on low income customers. Provided recommendations as to specifications in the client's cost of service analysis (COSA) model for deriving Open Access Transmission Tariff rates, using FERC approved standards to guide the evaluation. Conducted an electric utility costing and pricing workshop for the PUB in October 2017; and participated with Tacoma Utilities staff in a comprehensive electric and water Rates and Financial Planning workshop in February 2018. Engagement was extended for the 2019 – 2020 rate filing, which will incorporate the Black & Veatch municipal COSA model for costing and ratemaking purposes. Currently working with Tacoma Power for the potential incorporation of financial forecasting capabilities and revenue requirements development into the COSA model. Future project work involves working on the re-design of the general service and industrial rate schedules, economic development rate strategies, demand response rates, and other innovative rate programs, such as Electric Vehicle charging and carbon free rate options.

Tacoma Power (2017)

Engaged to review and assess current rates for 3rd Party Pole Attachments (PA), and more specifically, to determine and recommend if any rate adjustments were needed. Performed several tasks:

- Performed a market survey of rates charged by comparable utilities;
- Reviewed current regulations on rate setting and practice for 3rd Party Pole Attachments as set forth by the Federal Communications Commission (FCC) and the State of Washington (WA), and the interpretation of such regulations in court decisions;

- Reviewed industry best practices under the FCC, WA, and the American Public Power Association (APPA);
- Collected and reviewed data for cost based fees including:
  - Application Fees
  - Non-Compliance Fees
- Reviewed cost data supplied by the City of Tacoma as relates to determining pole costs; and
- Performed modeling of rates under the FCC Model, the APPA model and the State of Washington shared model (50 % FCC Rate/ 50% APPA Rate).

Cascade Natural Gas Corporation (2015 – Present)

Provided cost of service and rate design support for the company's six general rate case filings in its two state jurisdictions, Oregon and Washington. Conducted Long-run Incremental Cost Studies in the Oregon jurisdiction and embedded class allocated cost of service studies in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general (A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discuss accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013, 2017 – 2018)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in three general rate cases before the Indiana Utility Regulatory Commission.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. Canada.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric operations. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

NW Natural (2008)

Provided cost of service and rate design support for the utility's Washington general rate case, including expert witness testimony. Assisted the client with an earlier revenue neutral reconfiguration of its Oregon commercial/industrial sales and transportation service offerings. The earlier initiative included collaborative work with an industrial customer stakeholder group.

Integrys Energy (2007)

Assisted the client with the pursuit of alternative regulatory initiatives in conjunction with company's expansion of its energy efficiency and conservation programs. Supported the research, design, and selection of revenue decoupling mechanisms for its two Illinois regulated gas utility subsidiaries, Peoples Gas Light & Coke Utility and North Shore Gas Company. Served as the cost of service witness in two general rate case filings.

Puget Sound Energy (2001 – 2002, 2006 – 2007)

In two Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, electric power cost adjustment mechanisms and gas supply pricing options of utilities in North America.

Southern Union Company (2006, 2007)

Engagement director for cost of service and rate design support for the general rate proceedings of the company's Midwestern (Missouri Gas Energy) and northeastern Pennsylvania (PG Energy) gas utilities, including expert witness testimony on cost of service, rate design and declining use-per-customer. Rate design support included a proposed 10-year weather normal, and the introduction of straight-fixed variable rates (Midwestern LDC). This was the third consecutive rate case engagement for the Northeastern LDC.

Vectren Energy Delivery Ohio (2004 – 2005)

Assisted the company with the preparation of a retail customer choice filing for one of its gas distribution jurisdictions. Provided support for the development ancillary service costs, the design of program cost recovery mechanisms, and tariff structure for service offerings.

Connecticut Natural Gas (1999 – 2000, 2002 – 2003, 2005)

Served as engagement manager for cost of service and rate design support, including expert witness testimony, for the client's participation in a statewide gas unbundling proceeding. Subsequent projects included analysis of the client's demand forecasting capability, implementation of an algorithm-based balancing service and a cost of service studies related to transportation-related administrative costs, resources supporting system reliability and recovery of potentially stranded costs.

Sempra Energy (2001 – 2002)

Provided case strategy and cost of service support for the biennial cost allocation proceedings of its two utility subsidiaries, Southern California Gas and San Diego Gas & Electric.

BC Gas Utility Ltd. (now FortisBC) (2000 – 2001)

Served as engagement manager for cost of service and rate design support. Represented the client in its capital investment recovery proceeding for a major pipeline project, a cross-provincial (British Columbia) transmission pipeline. The three-phase project included regulatory strategy support for executive management regarding the integration of the pipeline proposal with the utility's Performance Based Ratemaking and unbundling initiatives and a global rate design proceeding. Cost of service support included a review of its gas cost portfolio allocation to firm sales customer classes, a survey of the trends in gas cost allocations and incentive mechanisms in North America, and serving as a facilitator for an all-party cost allocation and rate design workshop.

Oklahoma Natural Gas Company (ONEOK) (1999 – 2000)

Served as engagement manager for cost of service and rate design support, including expert witness testimony, for client's asset separation and unbundling proceeding as well as a subsequent general rate case. Integrated gas utility (wellhead to burner-tip) unbundled upstream services (production and gathering, storage, and intra-state transmission) from its distribution business.

Confidential South American Gas Utility (1999)

For an affiliate of a major U.S. energy company, conducted a cost of service and rate design training for management personnel engaged in the planned restructuring of the rate-setting processes for three gas utilities in Brazil.

Confidential Canadian Energy Marketer (1999)

Provided consulting support and position paper on cost allocation and pricing issues for Canadian gas marketer's participation in a restructuring collaborative sponsored by the intra-provincial pipeline and local distribution utility in Saskatchewan.

Washington Natural Gas (1995)

Negotiated and obtained regulatory approval of a 20-year contract with the company's largest industrial customer, which avoided bypass of 14 primary plant facilities within the service territory, prevented loss of annual throughput, and maintained contribution to system costs.

Washington Natural Gas (1995)

Obtained regulatory approval of unbundled, cost-based transportation services to meet large commercial and industrial customer needs and redesigned rates of other classes to better align with new cost of service methodology. The project required the facilitation of a collaborative working group of key industrial customers, customer associations, commission staff, and consumer advocacy agencies.

UTILITY SYSTEM OPERATIONS AND ORGANIZATIONAL DEVELOPMENT

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

California Water Service Company (2007 – 2008)

Engaged to manage the implementation of a new revenue decoupling mechanism into its 24 separate rate areas. Changes to the following processes and related procedures were required: rate setting, meter reading, billing, revenue and financial reporting. Microsoft Project was used to manage and track the implementation throughout the following organizations: Rates, Accounting, Information systems, Communications, and Customer Service.

Puget Sound Energy (2007)

Conducted an evaluation of the company's key accounts (Top 100) and business account services organization. Work included compilation of "best practices" from peer group utilities, recommendations related to staffing levels, roles and responsibilities, and the interrelationships with the customer service (call center), revenue management and community relations organizations of the utility.

Washington Gas Light (2006)

Provided market monitoring strategies and action plans based on an analysis of competitive threats and discussions with the client's customers and other utilities facing similar issues. Intent of recommended monitoring strategies and corresponding action plans to result in increased customer growth (meters) and/or customer retention, including a prioritized implementation approach to the monitoring strategies and action plans, based on benefits to the client and time to implement.

Entergy New Orleans / Entergy Gulf States (2004 – 2005)

Conducted an evaluation of the two gas operating subsidiaries' capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.

Austin Energy (1997 – 1998)

Engaged as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process, which involved establishing the organization structure, span of control, job descriptions, qualifications, and salary ranges. The team worked closely with the head of the new organization, the municipal utility management, and the relevant municipal government agencies. Also facilitated numerous management and stakeholder meetings.

TXU Energy (1997)

Provided research and consulting support to establish performance metrics and benchmarks from peer group companies for the client's performance management system.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Kansas Corporation Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

PROFESSIONAL HISTORY

Black & Veatch (Present)

Director – Advisory & Planning

Concentric Energy Advisors, Inc. (2007 – 2013)

Vice President

Navigant Consulting, Inc. (1997 – 2007)

Director

Puget Sound Energy, Inc. (1997)

Manager – Federal Regulatory Affairs

Washington Natural Gas Company (1993 – 1997)

(Merged with Puget Power & Light to form Puget Sound Energy in 1997)
Director – Rates

Indiana Energy (now Vectren) (1984 – 1993)

Regional Director – Distribution Operations
Director – Rates

Ohio Valley Gas Corporation (1978 – 1984)

Information Systems
Distribution Operations

SELECTED PUBLICATIONS/PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014