BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 390

Cascade Natural Gas Corporation

Direct Testimony of Nicole A. Kivisto

EXHIBIT 100

March 2020

EXHIBIT 100 – DIRECT TESTIMONY

TABLE OF CONTENTS

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"), Intermountain Gas Company, and Montana-Dakota Utilities Co. ("Montana-Dakota"), all subsidiaries of MDU Resources Group, Inc. ("MDU Resources") as well as Great Plains Natural Gas Co. a division of Montana-Dakota, collectively the MDU Utilities Group.

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. Please briefly describe your educational and professional background.

A. 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. 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;
- Summarize the Company's rate request in this filing and the primary drivers of the need for rate relief, provide background on increasing costs facing the Company, and provide context for the timing of this rate case filing;
- Describe measures the Company has taken to control costs and increase operating efficiencies;
- Present Cascade's overall proposed Rate of Return, Return on Equity, and Capital Structure;
- Describe the Company's customer support programs, and
- 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. As of December 31, 2019, Cascade has 299,000 customers, of which 77,000 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 331 dedicated employees. Cascade became a subsidiary of MDU Resources in 2007.

IV. REASONS FOR RATE INCREASE REQUEST

Q. Please summarize Cascade's requested increase in this filing.

A. The rate increase request is largely driven by increased investment in the safety of our system. Cascade is requesting a base rate increase of $4,507,842 or 6.67 percent. This increase is based on an overall rate of return of 7.08 percent, with a capital structure common equity component of 50 percent, and a return on equity of 9.40 percent. The Company is also seeking an increase in the amortization of deferred Environmental Remediation costs of $363,765 or an additional 0.54 percent, which is independent from the proposed increase to base rates. The combined increase would be $4,871,607 or 7.21 percent. The Company is using a partially forecasted test period of the calendar year 2020 ("Test Year"), and the base year is the twelve months ended December 31, 2019 ("Base Year"). The partially forecasted Test Year was selected as the most appropriate and supportable for the period during which rates will be in effect, and Maryalice Peters provides further discussion regarding the Test Year 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 witness, Pamela Archer, 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 58 therms per month, the average residential customer will see a bill increase of $4.25 per month from, $50.23 to $54.48. This equates to an average increase on a residential customer bill of 8.46 percent.

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

A. The primary driver is the Company's investment associated with pipeline replacement projects. In 2011, as required by the Department of Transportation, Cascade developed 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 nine of a multi-year plan to completely replace the original system. Cascade has also initiated or recently completed several other similar safety-related replacement projects, such as its Pendleton, Baker City, and Madras pipeline replacement projects.

Q. Are there other capital additions planned for 2020 and beyond that will also apply pressure on rates?

A. Yes. Cascade's projected capital investment for each of the next five years focuses on the replacement of our highest risk of failure systems. Our capital investment in each year is expected to far exceed our annual depreciation expense which places tremendous pressure on the need for continual rate relief in the form of general rate cases.

Q. How much of the current base rate requested increase of $4.5 million is due to 2020 capital investments?

A. The revenue requirement associated with the 2020 capital investments account for $3.16 million of the total requested increase.

Q. Was capital investment in 2019, the base year in this case, also a significant driver?

A. Absolutely. Cascade's last general rate case had 2018 as its test year. In 2019 Cascade added over $17 million of new investment which was a major driver for Cascade under earning in 2019.

Q. Please identify any other drivers of the proposed increase.

A. The other major cost drivers are wage increases, depreciation expense due to added investment and new proposed depreciation rates from the depreciation study in UM 2073. These costs combine for approximately $360,000 of the proposed increase.

Q. How has Cascade controlled costs in order to mitigate the impact of 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 allows the Company to scrutinize and prioritize 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 aggressive cost management approach is also demonstrated in the adjustments included in Exhibit CNGC/304, which shows that the primary increases are safety investment and employee costs.

Q. Please explain the timing for the Company's rate case filing.

A. As I mentioned above, Cascade is facing significant rate pressure on account of the capital projects investments incurred since the last rate case and capital projects that are planned for 2020, in addition to increased expense attributable to the wage and salary increases and increased expense resulting from the Company's proposed revised depreciation rates. Cascade has been working on and planning this rate case filing for the past several months and targeted the end of March 2020 for its filing to allow for rates to become effective on February 1, 2021.

Q. Have any major events occurred since Cascade began planning this rate case filing?

A. Yes. Between the time we began preparing this case and the time of filing, the novel infectious coronavirus ("COVID-19") pandemic has taken hold across the country, and in Cascade's Oregon service territory. Governor Kate Brown declared a state of emergency over the COVID-19 pandemic and has closed schools and certain businesses to prevent the spread of infection. For the businesses that remain open, many workplaces have shifted to remote working or implementing social distancing protocols. These closures and changes to work practices, while vital to protecting to the public health, have also resulted in business disruptions and volatility in the market.

Q. Do you expect that the business disruptions and market volatility resulting from the COVID-19 pandemic will impact the rate increase proposed in this case?

A. At this time, it is difficult to predict with any certainty the impacts that may result from the COVID-19 pandemic during the pendency of this rate case. To the extent that

Cascade discovers that changed circumstances resulting from the COVID-19 pandemic impact any key components of the Company's proposed rate increase, Cascade will update the Commission and the parties to this case. Cascade has filed a deferral request with the Commission (UM 2072) to capture uncontrollable costs that may occur as a result of the COVID-19 pandemic. However, Cascade is not including any impacts of the event in this case.

Q, How is the COVID-19 pandemic impacting Cascade and its customers?

A. Cascade is implementing appropriate measures to ensure that it can continue to operate safely and ensure that the Company's customers can continue to receive essential gas service during this challenging time. To that end, the Company has temporarily suspended the collection of late payment charges for its customers and has implemented a moratorium on service disconnections for non-payment related to hardships incurred from COVID-19.

Q. Has Cascade considered the impact of filing a general rate case during these trying times?

A. We understand that our customers may now (or soon) be experiencing economic hardship resulting from the COVID-19 pandemic, and that the prospect of a rate increase may be difficult for the Company's customers. We carefully considered the appropriate timing for our filing and ultimately determined that the rate increase is necessary in order to meet our customers' needs in regards to maintaining a safe, reliable service as well as provide timely recovery of our investments and costs. While there is uncertainty regarding how long Cascade and its customers will be impacted by the COVID-19 pandemic and the magnitude of the impacts, Cascade is optimistic that the situation will be improved by the time rates go into effect on February 1, 2021.

V. RATE OF RETURN, RETURN ON EQUITY, CAPTITAL STRUCTURE

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 7.08 percent with a capital structure of 50 percent equity and 50 percent 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%	4.75%	2.375%
	100%		7.075%

Q. Why does the Company believe a capital structure of 50 percent equity and 50 percent 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 December 31, 2019, Cascade's actual capital structure was at 54.7 percent 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/101.

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

A. The Company is proposing a 9.40 percent ROE in order to reduce costs to all parties and ultimately rate payers in the form of consultant fees and administrative time involved in determining the proper ROE. For purposes of meeting this objective Cascade believes 9.40 percent is reasonable and adequate, and is consistent with the Commission's recent determination for ROE in Cascade's last general rate case which was effective April 1, 2019,[1] as well as the most recent general rate case for another natural gas utility.[2]

VI. 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.

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

---

[1] *See in the Matter of Cascade Natural Gas Corp., Application for a Gen. Rate Revision*, Docket No. UG 347, Order No. 19-088 (Mar. 14, 2019).

[2] *See In the Matter of Avista Corp., dba Avista Utils., Request for a Gen. Rate Revision,* Docket No. UG 366, Order No. 19-331 (Oct. 8, 2019).

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, 2019, 5,792 or 7.5 percent of Oregon customers participate in the Budget Payment Plan.

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. Patrick Darras, Vice President – Engineering & Operations Services, will support the Company's proposed plant additions.

Ms. Maryalice Peters, Regulatory Analyst, will discuss the Revenue Requirement model and each of the associated adjustments to the Base Year and related exhibits that were used to derive the revenue requirement for the Test Year.

Mr. Isaac Myhrum, Regulatory Analyst, discusses the Base Year revenue proof and the proposed revenue increase.

Ms. Pamela Archer, Senior Regulatory Analyst, presents the Company's long-run incremental cost study for the Oregon service territory. Ms. Archer discusses her study results and how each rate schedule's present and proposed rate compares to the indicated costs. Ms. Archer also presents the Company's proposal to update its current tariff, P.U.C. Or. No. 10.

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

A. Yes.

CNGC/101
Kivisto

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Nicole A. Kivisto
Exhibit No. 101

Cascade's Actual Capital Structure
2014-2019

Cascade Natural Gas Corp
Actual Capital Structure

	12/31/2014	12/31/2015	12/31/2016	12/31/2017	12/31/2018	12/31/2019	Average	Projected End of 2020
Total Debt	49%	53%	52%	50.8%	48.9%	45.3%	49.8%	49.8%
Common Equity	51%	47%	48%	49.2%	51.2%	54.7%	50.2%	50.2%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 390

Cascade Natural Gas Corporation

Direct Testimony of Patrick C. Darras

EXHIBIT 200

March 2020

EXHIBIT 200 – DIRECT TESTIMONY

TABLE OF CONTENTS

I. INTRODUCTION

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

A. My name is Patrick C. Darras and my business address is 400 North Fourth Street, Bismarck, North Dakota 58501. I am the Vice President – Engineering & Operations Services for Cascade Natural Gas Corporation ("Cascade" or "Company"), Intermountain Gas Company ("Intermountain"), Montana-Dakota Utilities Co. ("Montana-Dakota"), and Great Plains Natural Gas Co. ("Great Plains").

Q. Please describe your duties and responsibilities with Cascade.

A. I have executive responsibility for the development, coordination, and implementation of Company strategies and policies relative to areas of engineering and operations including design, construction, compliance, and pipeline integrity and safety.

Q. Please outline your educational and professional background.

A. I am a graduate of North Dakota State University with a Bachelor of Science Degree in Construction Engineering. I also hold an MBA along with a Master's Degree in Management, both from the University of Mary. In June of 2014 I attended the Utility Executive Course at the University of Idaho.

I began my career in 2002 as a gas engineer with Montana-Dakota in Bismarck, ND. I held that position for four years primarily working with the construction and service group in day to day operations. In 2006, I was promoted into the role of Region Gas Superintendent where I was responsible for the overall gas engineering, construction, and service of the Dakota Heartland Region of Montana-Dakota. I worked in that capacity for two years and was then promoted to Region Director for Montana-Dakota's Dakota Heartland Region and Great Plains. My responsibility in this role was oversight of all gas and electric operations for the Region. In January 2015, I accepted the promotion to Vice

President of Operations for Montana-Dakota and Great Plains. My responsibilities in this role included gas and electric distribution operations and engineering across the five states of North Dakota, South Dakota, Montana, Wyoming, and Minnesota. In June of 2018, I accepted my current role of Vice President – Engineering and Operations Services.

Prior to joining Montana-Dakota, I worked for a local industrial contractor specializing in refinery and power plant maintenance along with turn-key construction of industrial facilities such as refineries and food processing plants. I spent seven years with this group in various capacities in engineering, construction, and project management.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) provide an overview of the Company's project selection and budgeting process; (2) provide an overview of the Company's major capital projects that have been completed since the last rate case or are currently in progress—which include the Bend 6" HP Line Replacement project, the Bend 6" Shevlin Park project, the Bend 6" PE Ponderosa St. Reinforcement, the Bend 2" Phase 8 Sec 2 project, the Redmond 6" HP Line and Regulator Station, and the Madras 4" HP Replacement; (3) describe the Company's blanket funding projects; and (4) describe the Company's Customer Care and Billing System Upgrade.

II. OVERVIEW OF PROJECT SELECTION AND BUDGETING PROCESS

Q. What types of major capital projects does the Company typically perform?

A. The bulk of Cascade's major capital projects are pipeline replacement projects that have been identified for safety reasons and to reduce risk on Cascade's system, or system reinforcements or system expansions that have been identified as needed to ensure system reliability and to accommodate growth on the Company's system. A reinforcement is an upgrade to existing infrastructure or new system additions, which increases system capacity, reliability, and safety. An expansion is a new system addition to accommodate an increase in demand. Collectively, these are known as distribution enhancements.

Distribution system enhancements do not reduce demand, nor do they create additional supply. Instead, enhancements can increase the overall capacity of a distribution pipeline system while utilizing existing gate station supply points. The two broad categories of distribution enhancement solutions are pipelines and regulators.

Q. How does the Company identify safety-related projects?

A. The Company uses the Distribution Integrity Management Program ("DIMP") and the expertise of its own engineers and district managers to identify areas of risk on its system and to develop the safety projects required to remediate risk. The DIMP supports Cascade's understanding of the system and material characteristics and are used to identify, assess, and prioritize integrity risks to Company-owned and operated infrastructure. The Company reviews and analyzes the DIMP risk model outputs after each model run to identify areas of highest risk and those areas where risk increased from the last model run.

Additionally, because the DIMP model does not perfectly capture all risk factors, the Company also considers input from its system engineers, district managers, and other subject matter experts ("SMEs") who have intimate knowledge of specific portions of Cascade's system to identify other areas of potential concern.

The Company then considers and analyzes existing and proposed measures to address the threats to Cascade's pipeline system. The prioritization and selection of the appropriate remediation actions depends on the type of threat being addressed, whether the threat is current or potential, and the viability of the remedial action in managing the relevant risk factors.

Q. What types of projects are typically performed to address safety-related concerns?

A. Pipeline replacement is typically the most viable option to remediate risks associated with corrosion, natural forces, material, weld, joint, and/or equipment. If Cascade determines that replacement is an appropriate action to reduce the risk, the Company establishes a replacement project.

Q. How does the Company prioritize and select safety-related projects?

A. Once pipe segments requiring replacement have been identified via the DIMP, the Company plans and prioritizes specific projects within these segments. This process ensures that higher risk threats are mitigated in a timely manner.

Q. Please provide an overview of Cascade's identification and selection process for distribution enhancement projects.

A. The engineering department works closely with energy services representatives and district management to ensure the system is safe and reliable. As towns develop and add new homes and businesses, the need for pipeline expansions and reinforcements increases. The system expansion projects are historically driven by new city developments or new housing plats. Before expansions and installation can be constructed to serve these new customers, engineering analysis is performed. Using system modeling software to represent cold weather scenarios, predictions can be made about the capacity of the system. As new groups of customers seek natural gas service, the models provide feedback on how best to serve them reliably.

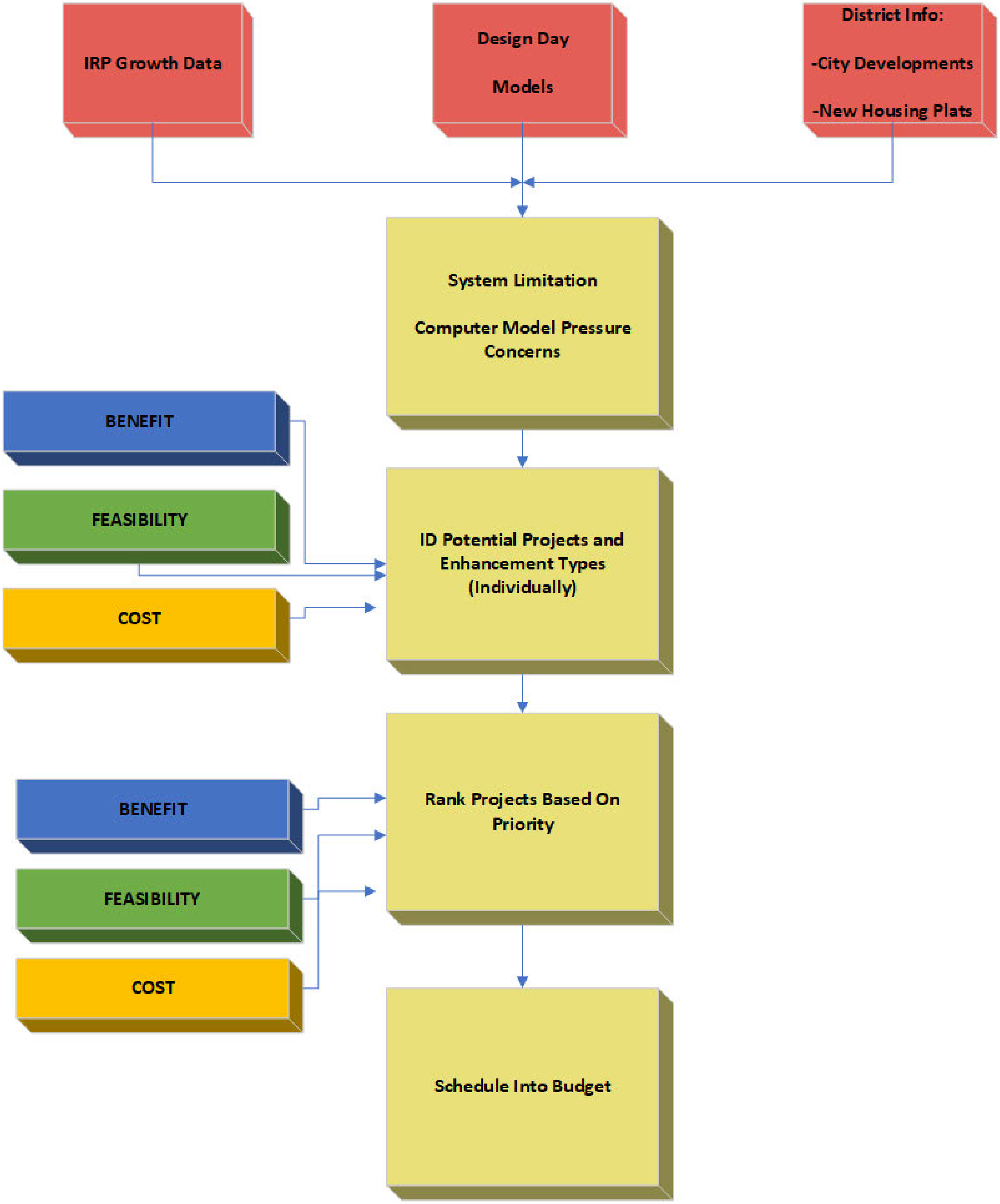
Another aspect of system planning involves gate capacity analysis and forecasting. Over time, each gate station will take on more and more demand and it is Cascade's goal to stay ahead of potential reliability issues by predicting and identifying constraints on its system. The IRP growth data, along with design day modeling, allows Cascade to forecast necessary gate upgrades. SCADA technology utilized by Cascade allows verification of numbers with real time and historic gate flow and pressure data.

Demand studies facilitate modeling multiple demand forecasting scenarios, constraint identification, and corresponding optimum combinations of pipe modification, and pressure modification solutions to maintain adequate pressures throughout the network. After developing a working demand study, the Company analyzes every system at design day conditions to identify areas where potential outages may occur. These constraint areas are then risk-ranked against each other to ensure the highest risk areas are corrected first and that others are properly addressed. Within a given area, projects/reinforcements are selected using the following criteria:

- The shortest segment(s) of pipe that improves the deficient part of the distribution system.
- The segment of pipe with the most favorable construction conditions, such as ease of access or rights or traffic issues and minimal to no water, railroad, major highway crossings, etc.
- The segment of pipe that minimizes environmental concerns including minimal to no wetland involvement, and the minimization of impacts to local communities and neighborhoods.
- The segment of pipe that provides opportunity to add additional customers.
- Total construction costs including restoration.

Once a project/reinforcement is identified, the design engineer or energy services representative begins a more thorough investigation by surveying the route and filing for permits. This process may uncover additional impacts such as moratoriums on road excavation, underground hazards, discontent among landowners, etc., resulting in another iteration of review of the above project/reinforcement selection criteria. Figure 1, below, provides a schematic representation of the distribution project process flow.

Figure 1. Distribution Planning Project Process Flowchart



Q. Does the Company also consider demand side management alternatives?

A. Yes. The Company also reviews the impacts of proposed conservation resources on anticipated distribution constraints. Although Cascade provides utility-sponsored conservation programs throughout its Oregon service territory, there may be instances where a more targeted approach could reduce or delay the estimated reinforcement for a specific area. While Cascade attempts to influence these decisions through its conservation programs, the consumer is still the ultimate decision maker regarding the purchase and use of a conservation measure. Therefore, in the short term, Cascade does not anticipate that the peak day load reductions resulting from incremental conservation will be adequate to eliminate distribution system constraint areas at this time. However, over the longer term, the Company plans to continue to explore opportunities for targeted conservation programs to provide a cumulative benefit that offsets potential constraint areas.

Q. How does the Company's Integrated Resource Planning ("IRP") process inform project selection?

A. Cascade's IRP includes the evaluation of safe, economical, and reliable full-path delivery of natural gas from basin to the customer meter. Securing adequate natural gas supply and ensuring sufficient pipeline transportation capacity to Cascade's city gates are necessary elements for providing gas to the customer. The other essential element is ensuring the distribution system growth behind the city gates is not constrained. Important parts of the distribution planning process include forecasting local demand growth, determining potential distribution system constraints, analyzing possible solutions, and estimating costs for distribution system enhancements.

Analyzing resource needs in the IRP ensures adequate upstream capacity is available to the city gates, especially during a peak event. Distribution planning focuses on determining if adequate pressure will be available during a peak hour. Given this nuance, distribution planning addresses many of the same goals, objectives, risks, and solutions as resource planning.

Q. Are all of the major projects identified in the Company's IRP?

A. No. Safety-related projects are not typically included in the IRP due to the nature of safety-related projects being required by Federal and State Pipeline Safety regulations and to ensure we are operating our gas system in the safest means possible. Generally, the projects that are included in the IRP are distribution enhancement projects, which address system capacity and growth.

Q. Please provide an overview of Cascade's capital project budgeting process.

A. Capital additions and changes are planned through the annual budget process using PowerPlan ("PP"). The budget process begins with an individual (originator) creating specific funding projects in PP for all new projects to be included in the five-year capital budget. Originators are generally managers at the district level or engineering staff at the corporate level. Sources of information for capital projects include the IRP, DIMP, TIMP, state and local government agencies, and internal Cascade personnel. Funding projects are used to hold the capital budget estimates and will be linked to the capital work orders to be created when actual costs commence. A Fixed Asset Financial Analyst reviews the funding projects for proper setup. If the project is not considered a capital expenditure as it was submitted, it is rejected and sent back to the originator for revision, cancelled, or it is moved to Operations and Maintenance ("O&M") Expense. After the review has been completed; the Fixed Asset Financial Analyst will add appropriate overheads and approve the funding project. Blanket funding projects are used year after year to budget for high volume mass property work orders typically under $100,000 each.

Once all the funding projects have been updated with expenditures, various Company operating managers generate reports to show estimated expenditures and justification for each project. The managers perform the review of funding projects and see that any necessary changes are made to the estimate and that the project is supported. Reports are then generated by the budgeting personnel for review and approval by the Directors and Vice Presidents of the Utility Group. Any final budget changes are made, and the budgets are then presented to the Utility Group's President for review and approval. The final Utility Group budget is then presented to the MDU Resources CEO for review and approval. If the budget is approved by the MDU Resources CEO, the final review and approval occurs with the Board of Directors. At each stage of review and approval process a project (or projects) can be challenged for appropriateness and removed from the capital budget or moved to another year within the five-year budget. The addition or removal of projects can also be impacted by other factors such as available capital and/or borrowing capacity.

After final approval, an approved budget version is created in PP and locked for entry and the funding projects and estimated amounts in the approved budget version are copied back to the working budget version. Project managers are notified that the budget has been approved and the funding projects are open for work order creation. Projects are monitored and updated throughout the year as part of the review process and to insure, as best as possible, that projects are completed on time and within the approved budget.

Q. Have there been any changes to these processes since the Company's last rate case?

A. Yes. Beginning in January 2019, the Company's parent, MDU Resources has moved toward a "one utility" model. As a result, the engineering department was reorganized, and more consistent tasks and processes were defined. Within this effort, there is a new internal requirement to develop a more robust analysis for any project with a cost estimate over $1 million dollars. As part of the that analysis, the Company develops documentation supporting the project, including a substantial executive summary, Synergi model snapshots, alternatives considered, and timing and justification. The engineering managers and directors collaboratively review all projects and determine which are the most important from a risk standpoint and what the timing of the projects should be to best mitigate risks.

Q. For work that will be performed in 2020, does the Company anticipate that its actual investment may vary from the budgeted amounts?

A. Yes. The Company's capital budgets were developed in November 2019, and the Company expects that its actual investment may differ from the budgeted amounts for the projects that are not yet complete. Additionally, while currently ongoing construction work is still being performed during the COVID-19 pandemic, and Cascade is not aware of any immediate impacts to the construction schedules for its capital projects, it is possible that there could be delays to certain projects resulting from the COVID-19 pandemic. The Company will provide updates regarding changes to budgeted amounts or actual investments, and any relevant changes in schedule, through discovery (as requested) and through the Company's rebuttal testimony.

III. MAJOR CAPITAL PROJECTS

Q. Please provide a brief description of the significant capital projects that are included for recovery in this case.

A. The Company is requesting recovery for the following significant capital projects:

- **Bend 6" HP Line Replacement ("Bend 6" HP – Phase 2").** The Bend 6" HP – Phase 2 is part of a multi-year high-pressure pipeline replacement project that began in 2017 with anticipated completion in 2024. The project will address safety and reliability concerns by replacing existing segments of pipe that had areas of minimal or no cover, which increases risk of damage. Phase 2 was designed in 2019 and intended for construction in 2019, however delays due to permit requirements with the City of Bend have pushed construction of Phase 2 to begin late spring 2020 with an anticipated in-service date of

June 2020.

- **Bend 6" Shevlin Park ("Shevlin Park Project").** The Shevlin Park Project is a reinforcement project designed to eliminate the need for the district to bypass during cold weather events and to address the supply issues presented by the ongoing accelerated growth in the western area of Bend. Design for the pipeline is currently underway, and construction is scheduled to for 2020 and 2021. The Company expects to complete a discrete 250-foot portion of the project in 2020.
- **Bend 6" PE Ponderosa Street Reinforcement ("Ponderosa Reinforcement Project").** The Ponderosa Reinforcement Project is a reinforcement project to address supply shortage during peak usage and eliminate the need to bypass. Design for the pipeline will be complete in April 2020. The Company anticipates that construction will begin in early July 2020 to utilize the lower summer flows and two-way feeds by installing the new pipe while removing the old pipe, a City of Bend requirement. The Ponderosa Reinforcement Project is expected to be completed in August 2020.
- **Bend 2" Pipe Replacement Project - Phase 8 Section 2A ("Bend 2" Pipe Replacement Project – Phase 8 – 2A").** This is Phase 8 Section 2A of a multi-year pipe replacement project in Bend. The project is designed to replace aging pipe and enhance system reliability. Construction started in October 2019 and was completed in March 2020.
- **Redmond 6" HP Line and New Regulator Station ("Redmond Project").** The Redmond Project is a system reinforcement project designed to address reliability problems and to provide service to increasing existing customer loads and proposed residential and commercial growth. Design for the pipeline is currently underway, and construction is planned to begin April 2020. The Company estimates that the Redmond Project will be complete and in-service by May 2020.

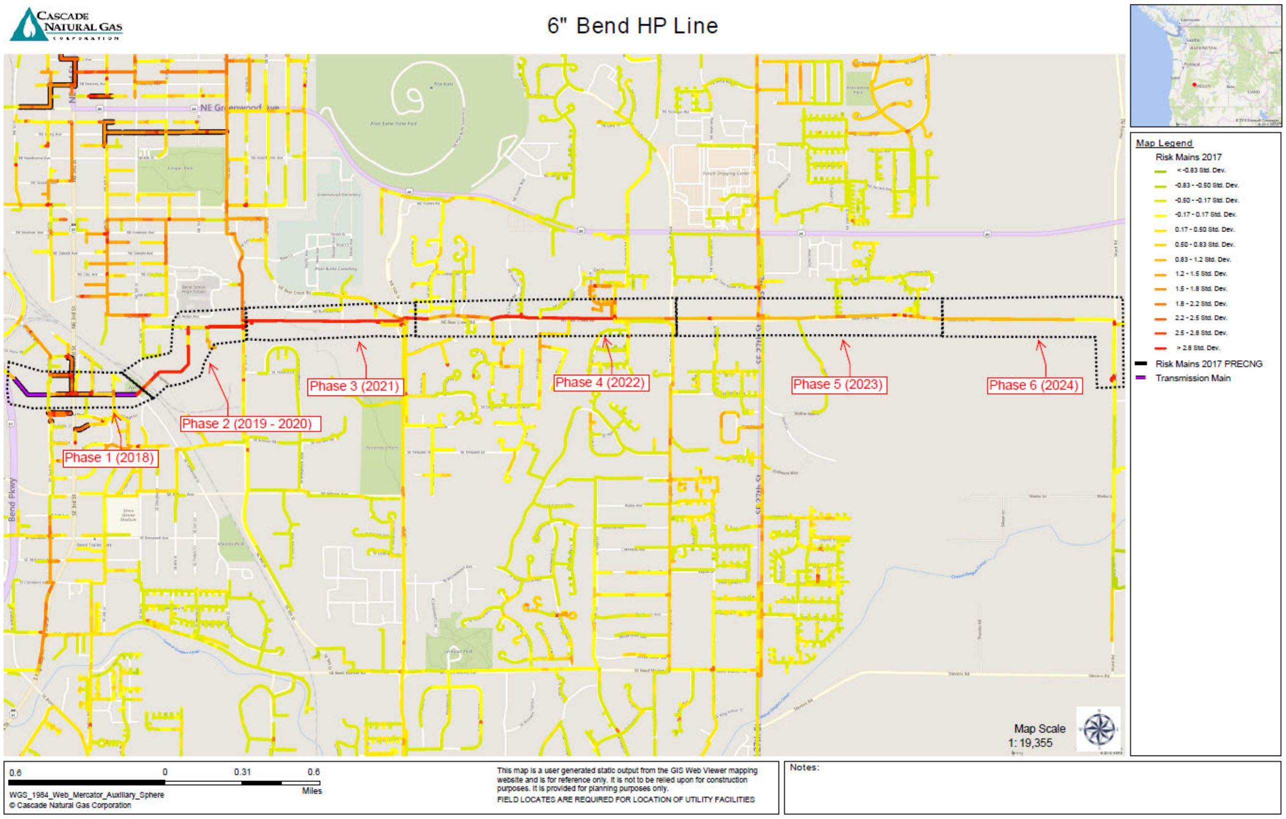
- **Madras Phase 3 - 4" HP Replacement ("Madras Phase 3").** Madras Phase 3 is the continuation of a multi-year high pressure pipeline replacement project that began in 2017 and will end with this phase. Madras Phase 3 will increase the safety and reliability of the Company's pipeline system in the Madras area by replacing the single feed line with known several integrity concerns. Design is near complete and construction is estimated to begin early summer with an anticipated in-service date of November 2020.

A. <u>Bend 6" HP – Phase 2</u>

Q. Please describe the Bend 6" HP Line and the Bend 6" HP Replacement Project.

A. The 6" Bend HP Line was installed in 1961 from the Bend Gate Station on Ward Road, following Bear Creek Road, until it terminates west of Bend Parkway and Highway 97 in Bend. The company began a multi-year project in 2017 to replace the high-risk sections of the 6" Bend HP Line with new 12" steel pipe to a depth of cover meeting current standards. The Bend 6" HP Replacement Project was split into phases, and each phase consists of replacing approximately 2500' – 4000' of existing 6" steel pipeline with new 12" steel pipeline. Phase 1 is complete, and Phase 2 was originally planned for 2019, but was delayed and is now scheduled for 2020. The Company is planning additional project phases in the future, and expects to complete all phases in 2024. The overall replacement project area is shown on the map below in Figure 2.

Figure 2. Bend 6" HP Replacement Project



Q. Why is the Company undertaking the Bend 6" HP Replacement?

A. The 6" Bend HP Line has many areas with minimal or no cover, which increases the risk of the pipe being damaged by excavation or from outside forces. This line currently has a high risk score in the Company's DIMP model and presents a safety issue with not having sufficient cover on a HP line that operates at a maximum allowable operating pressure ("MAOP") of 300 psig.

Q. What work was performed in prior phases of the Bend 6" HP Replacement?

A. The Company has completed Phase 1 of the Bend 6" HP Replacement, which was replacing 2,000 feet of 6" HP steel main with 12" HP steel main.

Q. What work will be performed in Phase 2?

A. For Phase 2 the Company will be replacing 2,700 feet of 6" HP steel main with 12" HP steel main.

Q. How will Cascade's customers benefit from this project?

A. This project gives Cascade an opportunity to replace old piping and, combined with the other projects in Bend, help improve capacity to areas experiencing low pressure during peak usage, along with providing additional capacity for new growth.

Q. Did the Company consider alternative ways to meet the need for this project?

A. No other alternatives adequately addressed the pipeline safety integrity risk or continued to provide the capacity needs for the City of Bend that this pipeline provides.

Q. What is the timing of the project?

A. Design is complete, and the Company is anticipating completing construction for this project by June 2020.

Q. What are the estimated costs for the project?

A. This project is anticipated to cost $2,064,240 in 2020.

B. Shevlin Park Project

Q. Please describe the Shevlin Park Project.

A. The Shevlin Park Project is a system reinforcement project that includes approximately 1.8 miles of 6" HP pipeline and a new regulator station.

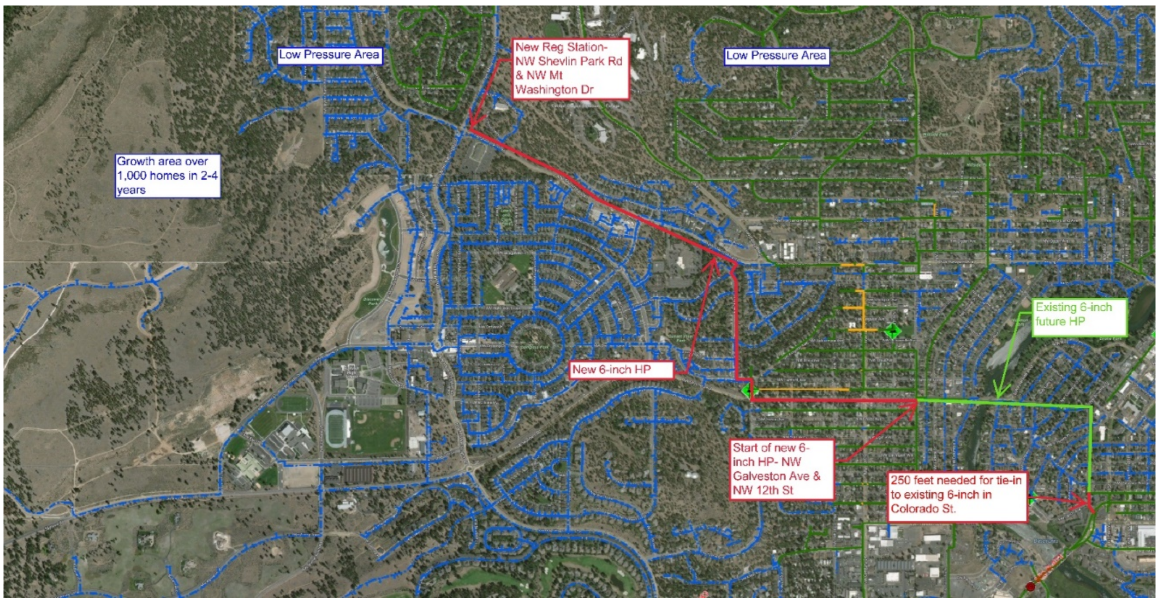
In 2012, in conjunction with replacement of aging main, 4,000 feet of 6-inch future HP steel main was installed from NW Broadway St and NW Delaware Ave to the intersection of NW 12th St and NW Galveston Ave, and this main was placed on nitrogen. An additional 250-feet segment of pipe needs to be installed from Delaware Ave to Colorado Ave to tie into the existing HP 6-inch main and gas up the future HP main.[1] Additionally, extending the 6-inch future HP main west and installing a regulator station is necessary to relieve

[1] Future HP main is defined as any gas facility designed and tested to operate at any pressure above 60 psig but currently has a Maximum Allowable Operating Pressure ("MAOP") specified as being 60 psig or below.

the low-pressure areas and accommodate for the growth in the western area of Bend.

The project site starts at NW Galveston Ave and NW 12th St and heads northwest to end at NW Shevlin Park Road and NW Mt Washington Drive. The location is shown on the map below in Figure 3.

Figure 3. Shevlin Park Project



Q. Why is the Company undertaking the Shevlin Park Project?

A. The pressure in the Bend northwestern distribution system during peak usage is below design criteria, which requires the Bend District to bypass during cold weather events. This area is located on the outer edge of the Bend distribution system, farthest from existing high-pressure pipelines and regulation. Though the customers in northwestern Bend are primarily residential, most are large homes with higher gas demand. The existing system cannot accommodate the ongoing accelerated growth in the western area of Bend that is contemplated over the next four years, taking into account the development that is currently in progress and already permitted by the City.[2]

---

[2] In October 2018, four developers on Bend's westside successfully negotiated a development agreement for the planning and development of more than 1,000 homes on 383 acres.

Q. How will Cascade's customers benefit from the Shevlin Park Project?

A. The new HP pipeline and regulator station will bring the northwestern Bend distribution system above design criteria during peak usage and cold weather events, eliminating the need for bypass operations. Additionally, this project allows Cascade to bring high pressure gas closer to the areas of Bend with larger residential gas load and allowing for gas service to be offered to new growth occurring in this area of accelerated development. The Synergi diagrams below in Figures 4 and 5 illustrate the anticipated improvements to the Bend system resulting from this project.

Figure 4. Synergi Model: NW Bend – Current Model

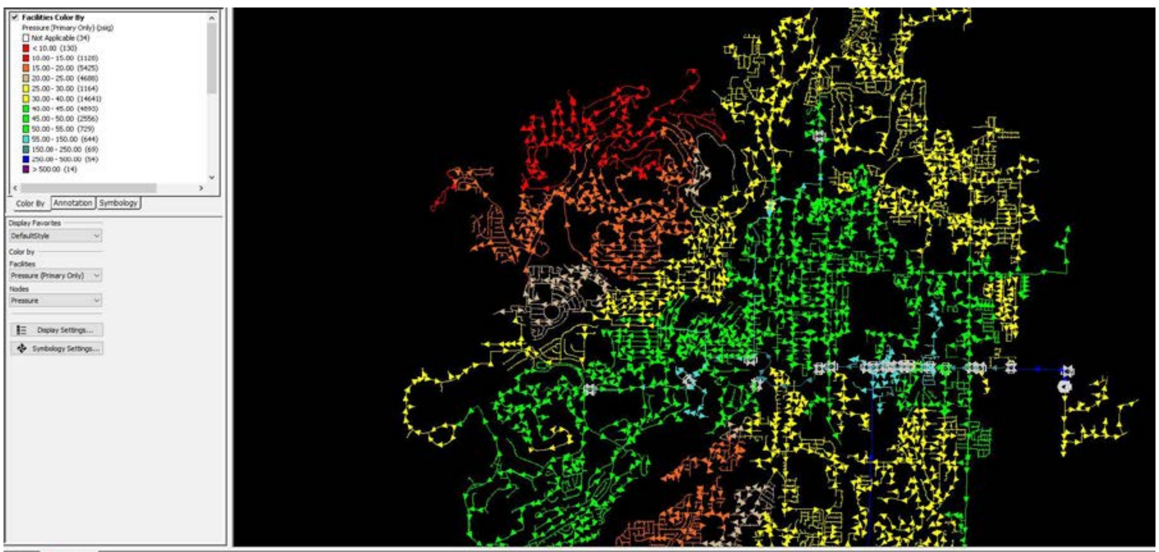


Figure 5. Synergi Model: NW Bend – Improved Model Upon Project Completion

As indicated in the legends for both diagrams, the areas of the map in red and orange indicate pressures below 20 psig. Operating at pressures below 20 psig can result in outages especially during cold weather events. The improved model after the reinforcement is completed (Figure 5) show these areas now operating at pressures above 20 psig (as shown by the yellow and green colors), therefore providing adequate pressure for new gas load and removing needs for remedial action during cold weather events.

Q. Did the Company consider alternative ways to meet the need for system reinforcement in the western Bend area?

A. Yes. In addition to the Shevlin Park Project as described above, the Company considered the following alternatives to address the system reinforcement needs:

1. **No reinforcement:** Under this alternative, the Company would not perform any reinforcement.
2. **Postponing reinforcement:** Under this alternative, Cascade would postpone reinforcement for 5 years.
3. **Shorter reinforcement:** Under this alternative, Cascade considered changing the route and making the new pipe installation shorter (3,000-4,000 feet), which would put

the high pressure pipeline and new regulator station farther away from the existing and new load.

Q. Why did the Company reject these alternatives and select the Shevlin Park Project?

A. None of the alternatives that the Company considered would adequately meet the Company's need to provide reliable service in the western Bend area and accommodate future load growth.

The Company determined that it could not pursue the first alternative (no reinforcement) because it would not address the Company's need to bypass during cold weather events to keep system pressures in the northwestern Bend system deliverable to customers. There are many factors that affect the decision to bypass regulation, some of these factors are dependent on current temperatures, inlet pressure from the transmission company, time of day, and flow rates. Due to these fluctuating variables, it is difficult to make a concrete rule on when bypass needs to occur and instead requires close on-site system observation often occurring in extreme weather conditions. There are risks involved with bypass operations with personnel required to manually bypass regulation and closely monitor system pressures to prevent over pressuring the downstream pipeline systems and customer services and meters. Other risks include not performing bypass operations soon enough and potentially losing gas service to thousands of customers.

The Company determined that it could not pursue the second alternative (postponement) because it would require Bend District personnel to continue to bypass during cold weather events until a reinforcement is in place. Additionally, Cascade needs to bring higher pressure and regulation closer to the load to provide service to new gas customers and developers building homes in the western Bend area. There are efficiencies and cost savings that can be achieved by installing gas mains while developments and construction are in progress, and it can be more difficult and expensive to install main and services at a later date when the system capacity is increased and new neighborhoods are built out with finished infrastructure (roads, sidewalks, storm, sewer, water, phone, cable, and power).

The Company determined that it could not pursue the third alternative (shorter reinforcement) because this option would not adequately meet the Company's needs for reliability. While the Company's modeling showed that a shorter reinforcement option would provide some improvements in the northern Bend distribution system, there were still customers in the western Bend distribution system that experienced pressures below design criteria and would result in continuing to need to bypass during peak usage and cold weather events.

As a result, the Company determined that the Shevlin Park Project was the best option to meet the Company's need for reinforcement in the area and accommodate future growth.

Q. Was the Shevlin Park Project included in the Company 2018 IRP analysis?

A. No. This project is being proposed to address growth associated with new proposed development in northwestern Bend, which was not yet known at the time the Company prepared its most recent IRP. The Company will analyze the Shevlin Park Project in its 2020 IRP, which will be filed in July 2020.

Q. What is the timing of the project?

A. Design for the pipeline is currently underway, and is scheduled to be completed in November 2020. Additionally, construction of the 250-feet pipe segment to tie-into the 6-inch HP on Colorado Ave is planned for 2020. The majority of the construction is planned to begin February 2021 and estimated to be complete and in-service by September 2021.

Q. What are the estimated costs of the project?

A. The estimated costs for the total project to be completed in 2020 and 2021, including pipeline and regulator station, are summarized below:

Materials	$	302,935.88
CNGC Labor	$	51,236.02
Contractor Costs	$	2,260,398.75
Resources	$	97,889.00
Subtotal	**$**	**2,712,459.64**
Corporate Overhead	**$**	**220,200.00**
Total Estimated Project Costs	**$**	**2,932,659.64**

Q. What are the estimated costs associated with the portion of the Shevlin Park Project that will be completed in 2020?

A. The estimated costs for the portion of the project that will be complete in 2020 are approximately $400,000.

Q. Is Cascade seeking cost recovery for the work to be performed in 2021 in this case?

A. No. The Company's request for cost recovery is limited to the discrete portion of the project that will be completed in 2020.

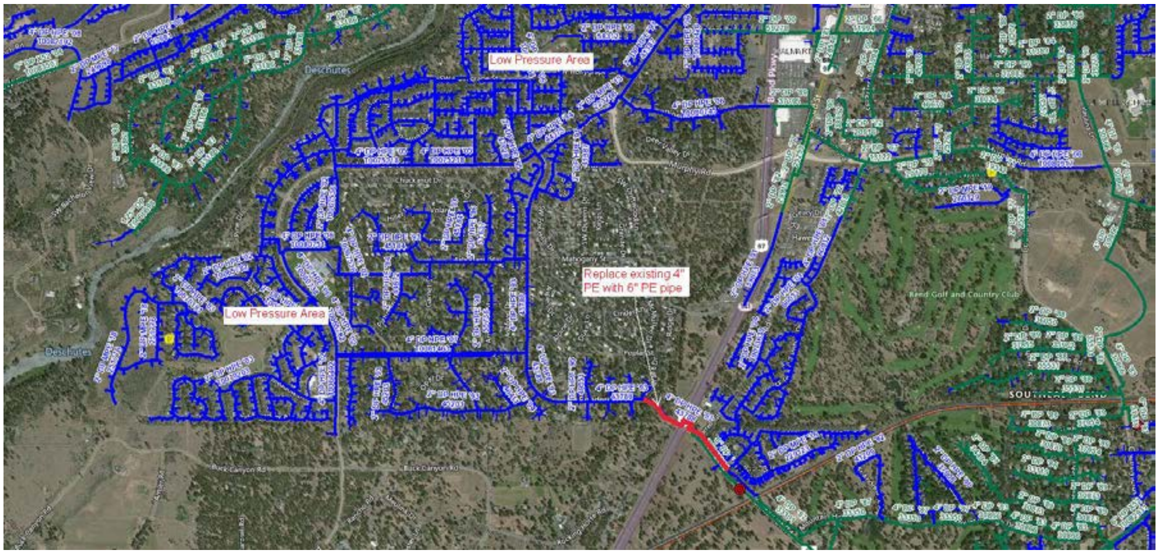
C. <u>Ponderosa Reinforcement Project</u>

Q. Please describe the Ponderosa Reinforcement Project.

A. The Ponderosa Reinforcement Project involves increasing the size of approximately 1,200 ft of existing 4-inch PE[3] in Ponderosa Street coming out of R-84, the regulator station that feeds this area. The project site starts at China Hat Road and Stonegate Drive and heads northwest to end at Ponderosa Street and Emigrant Drive. The location is shown on the map below in Figure 6.

[3] PE is polyethylene (plastic) pipe only used for distribution pressure, operating less than 60 psig.

Figure 6. Ponderosa Reinforcement Project.



Q. Why is the Company undertaking the Ponderosa Reinforcement Project?

A. The pressure in the Bend southcentral distribution system during peak usage is below design criteria and the system is isolated due to the river on the west and the highway to the east. This scenario results in the district needing to perform bypass during cold weather events and restricts the Company's ability to install reinforcement loops from areas of the system above design criteria.

Q. How will Cascade's customers benefit from the Ponderosa Reinforcement Project?

A. The new 6-inch pipeline will bring the southcentral Bend distribution system above design criteria and eliminate the need to bypass during peak usage and cold weather events. The Synergi diagrams below in Figures 7 and 8 illustrate the anticipated improvements to the Bend system resulting from this project.

Figure 7. Synergi Model: SC Bend – Current Model

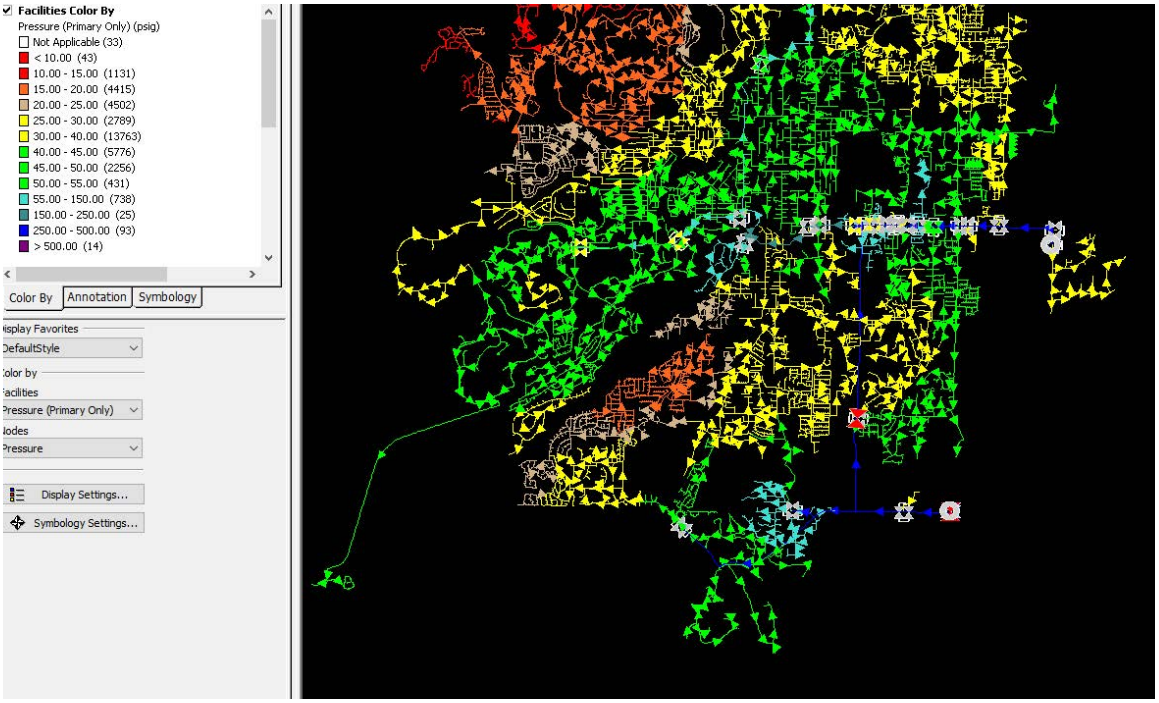
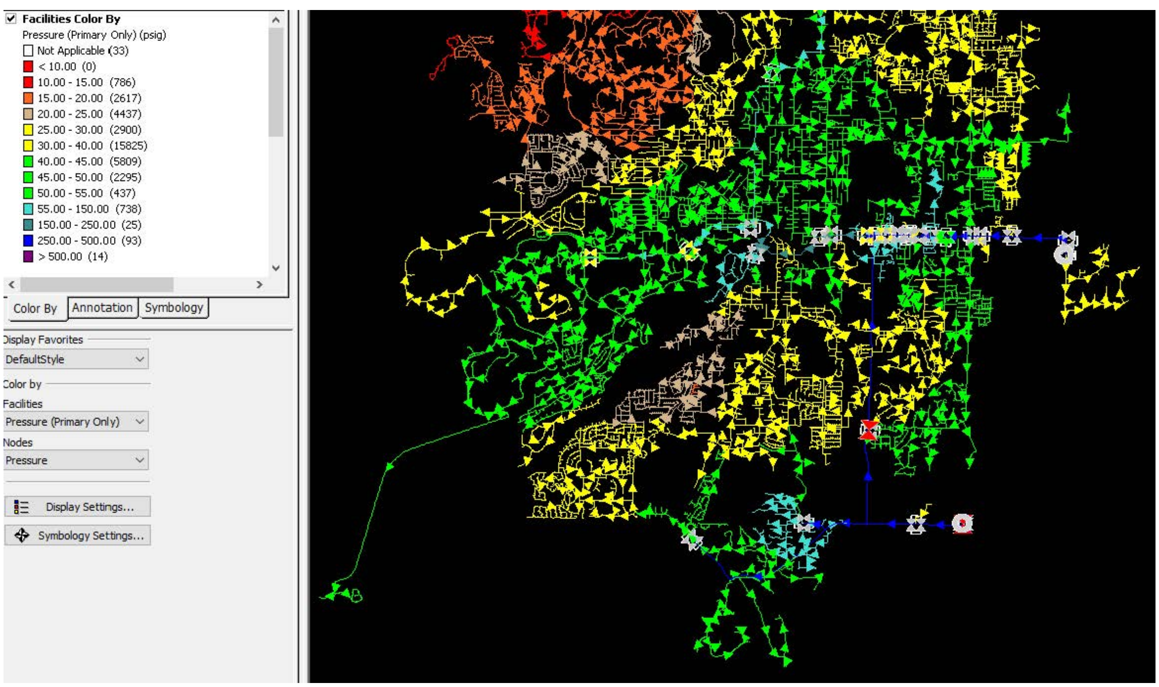


Figure 8. Synergi Model: SC Bend – Improved Model Upon Project Completion



As indicated in the legends for both diagrams, the areas of the map in red and orange indicate pressures below 20 psig. Operating at pressures below 20 psig can result in outages especially during cold weather events. The improved model after the reinforcement is completed (Figure 8) shows these areas now operating at pressures above 20 psig (as shown by the gray, yellow and green colors), therefore providing adequate pressure for new gas load and removing needs for remedial action during cold weather events.

Q. Did the Company consider alternative ways to meet the need for this project?

A. Yes. In addition to the Ponderosa Reinforcement Project described above, the Company considered several additional reinforcement alternatives for this area to determine which option offers the greatest system improvement, and is constructible, for the least cost.

1. **No reinforcement:** Under this alternative, the Company would not perform any reinforcement.
2. **Alternate Route 1:** Under Alternate Route 1, the Company evaluated the feasibility of installing 600 feet of 4-inch PE pipe under Highway 97 to connect the distribution system on SE Hayes Avenue.
3. **Alternate Route 2:** Under Alternate Route 2, the Company evaluated the feasibility of replacing approximately 1,500 feet of 2-inch steel pipe with 4-inch steel pipe in SE Badger Road.

Q. Why did the Company reject these alternatives and select the Ponderosa Reinforcement Project?

A. The alternatives that the Company considered would either not adequately meet the Company’s needs to provide reliable service in the southcentral Bend distribution area or were determined to be infeasible.

The Company determined that it could not pursue the first alternative (no reinforcement) because it would require district personnel to continue to need to bypass during cold weather events to keep system pressures in the southcentral Bend system deliverable to the customer. As explained above, there are numerous factors that affect the decision to bypass regulation, some of these factors are dependent on current temperatures, inlet pressure from the transmission company, time of day, and flow rates. Due to these fluctuating variables, is difficult to make a concrete rule on when bypass needs to occur and instead requires close on-site system observation often occurring in extreme weather conditions. Additionally, there are risks involved with bypass operations because district personnel must manually bypass regulation and closely monitor system pressures to prevent over pressuring the downstream pipeline systems and customer services and meters. Other risks include not performing bypass operations soon enough and potentially losing gas service to thousands of customers.

The Company determined that it could not pursue the second alternative (Alternate Route 1) because the route was not practical for construction due to other utility conflicts and the widened highway in the area. In addition, where the connections occur and feed into the system, this option would not provide the greatest improvement in system capacity.

The Company determined that it could not pursue the third alternative (Alternate Route 2) because due to the permitting requirements from the City of Bend to remove all abandoned pipe when installing new pipe in its place, the project was determined to be too costly for the amount of system benefit that could be achieved.

As a result, the Company determined that the Ponderosa Reinforcement Project was the best and most cost-effective option to meet the Company's need for reinforcement in the area.

Q. Was the Ponderosa Reinforcement Project analyzed in Cascade's 2018 IRP?

A. The need for the Ponderosa Reinforcement Project was analyzed and presented in the Company's 2018 IRP. However, at that time, the Company's analysis contemplated developing the Alternate Route 1, described above, which was later determined to be infeasible due to construction challenges. The Company has updated its analysis for its

2020 IRP to include the Ponderosa Reinforcement Project as described above.

Q. What is the timing of the Ponderosa Reinforcement Project?

A. Design for the pipeline will be complete in April 2020. The Company anticipates that construction will begin in early July 2020 to utilize the lower summer flows and two-way feeds by installing the new pipe while removing the old pipe, a City of Bend requirement. The Ponderosa Reinforcement Project is expected to be completed in August 2020.

Q. What are the estimated costs for the Ponderosa Reinforcement Project?

A. The estimated costs for the total project are summarized below:

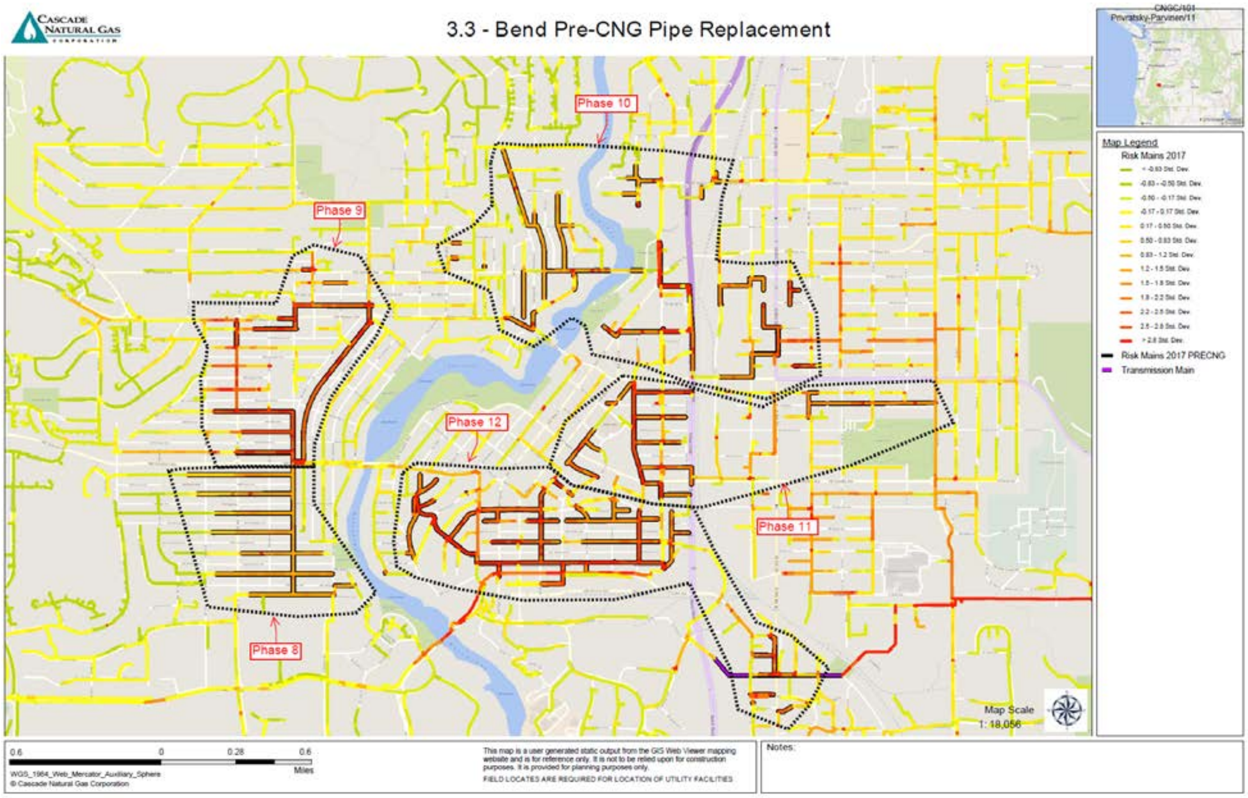
Materials	**$**	**10,941.04**
CNGC Labor	**$**	**4,719.94**
Contractor Costs	**$**	**186,688.20**
Other Direct Costs	**$**	**2,275.20**
Total Direct Costs	**$**	**204,624.37**
Corporate Overhead	**$**	**27,405.83**
Total Estimated Costs	**$**	**232,030.20**

D. Bend 2" Pipe Replacement Project – Phase 8 Section 2 A

Q. Please describe the Bend 2" Pipe Replacement Project.

A. In 2012 the Company started a multi-year pipeline replacement project in Bend, which involves the installation of new 2" pipe to replace 1930 vintage pre-manufactured gas main ("Pre-CNG pipe") in downtown Bend. The overall replacement project area is shown on the map below in Figure 9.

Figure 9. Bend 2" Pipe Replacement Project



Q. What is Pre-CNG pipe?

A. Pre-CNG pipe is pipe that was constructed to distribute manufactured gas or natural gas prior to 1955, and was installed, owned, operated, and maintained by other companies purchasing it in the late 1950's and the 1960's. Pre-CNG pipe tends to be bare or coal tar-wrapped steel pipe. The integrity of Pre-CNG pipe is concerning because it is at least 60 years old and had no, or inadequate, cathodic protection until the early 1970s, which means the pipe had a higher susceptibility to corrosion during the timeframe it was without cathodic protection. Pre-CNG pipe also has a higher missing value risk associated with the unknowns from purchasing the pipe from another company, and higher equipment risks due to age of the pipe and increased likelihood of failure.

Q. Why is the Company undertaking this project?

A. The Company has been working on the Bend 2" Pipe Replacement Project to replace older pipe, which is more susceptible to leaking, and to improve system reliability. The core of the downtown Bend Intermediate Pressure ("IP") Distribution System consists of areas of 1930's pipe that was purchased by Cascade from the City of Bend.

The Pre-CNG pipe in Bend has been found to be in poor condition with extensive corrosion due to the overall vintage of pipe. Areas have been discovered with wall loss in excess of 70 percent and is commonly referred to as "swiss cheese" by Cascade Bend District employees, who have worked on this system.

The Company's subject matter experts ("SMEs") have identified the Downtown Bend Pre-CNG pipe has one of Cascade's systems with the highest overall risk due to vintage of pipe, leaks, and severe corrosion concerns. Downtown Bend Pre-CNG pipe is also identified in the model as high risk based on the combination of high threat and high consequence factor.

Q. What work on the Bend 2" Pipe Replacement Project has already been completed?

A. Cascade started the Bend Pipe Replacement project to begin replacing Pre-CNG pipe with a new a PE and Steel system and an Accelerated Action is setup for the replacement of the Pre-CNG pipe. Since 2012 Cascade has completed eight phases of this pipe replacement project, totaling approximately 107,000' of main and services, and currently there is approximately 55,000' remaining to replace. Most recently, Phase 8 Section 1 was completed in 2019.

Q. What work is planned for Phase 8, Section 2?

A. Phase 8 Section 2 will continue off of Phase 7 and 8 Section 1 to replace the alleyways east and west of West 14th Street from Galveston to Commerce Ave. The project will consist of the retirement of approximately 2,500 feet of Pre-CNG pipe, installing approximately 2,500 feet of new 2" PE main, and replacing 43 steel services with PE (polyethylene) pipe and tie-over of 15 existing services.

Q. What additional work is planned for the future?

A. Currently there are five phases remaining to complete the Bend Pre-CNG pipe replacement project by the end of 2023. Each future phase will target approximately 11,000' of Pre-CNG main each year, along with connected service lines. The boundary of each phase can vary each year depending on construction challenges, planned municipal projects, resource availability, and permitting requirements. Cascade has been able to coordinate replacement work with City of Bend municipal projects to be able to reduce the overall costs needed for restoration.

Q. How will the Company's customers benefit from this project?

A. The benefits of the project are increased system and safety reliability by removing 1930 pre-manufactured gas pipe purchased from the City of Bend and replacing it with a new PE System. Additionally, completing the project will help reduce costs associated with leak repairs as well as upgrading an aging system to provide a safer gas distribution system.

Q. Did the Company consider alternative ways to meet the need for this project?

A. No alternative was identified. Given the age and poor condition of the pipe, the only option was to replace the existing pipe. Replacing this aging system allows us to provide a safer gas distribution system and eliminate costs involved with leak repairs on this system that needs to be replaced.

Q. What is the timing of the Bend 2" Replacement Project Phase 8 Section 2A?

A. Construction started in October 2019 and was completed in March 2020.

Q. What are the estimated costs of the project?

A. The estimated costs are as follows:

Phase 8 Section 2 A Mains Replacement - $612,119

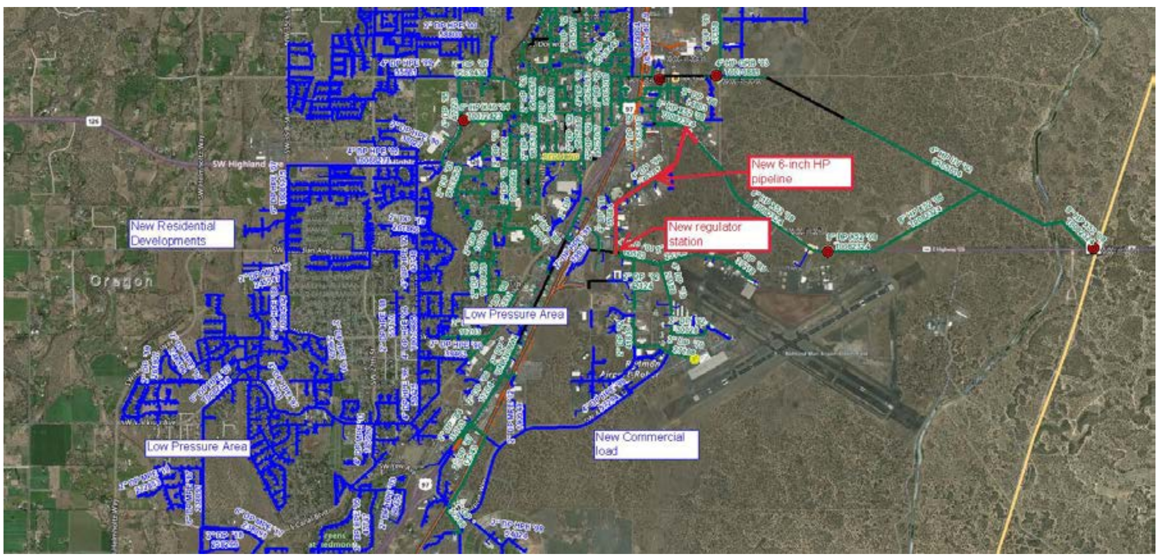
Phase 8 Section 2 A Service Replacement - $246,109

E. <u>Redmond Project</u>

Q. Please describe the Redmond 6" HP Line and New Regulator Station.

A. The Redmond Project is a system reinforcement project that consists of installation of approximately 1 mile of new 6" HP pipeline and a new regulator station in the Redmond area. This pipeline will operate at 300 psig. Considering the location and the site conditions, much of the pipeline will be installed via open trench with 3 bores across roadways and to maintain separation from conflicting utilities. The project site starts at E Highway 126 and SE Lake Road and heads southwest to end at Veterans Way. The location is shown on the map below in Figure 10.

Figure 10. Redmond Project



Q. Why is the Company undertaking the Redmond Project?

A. The pressure in the Redmond southern distribution system during peak usage is below design criteria. The existing system does not allow for residential and commercial growth, and the Company is now seeing increased commercial loads requested in the southern area of Redmond.[4]

[4] Redmond continues to be one of the strongest housing markets in Central Oregon. Home sales volume in Redmond increased by over 12 percent in the second quarter of 2019 year over year. The City's

While Cascade has several large volume industrial customers within the City of Redmond, the gas loads of industrial customers on an interruptible rate are not used in distribution planning modeling of the gas system. Cascade only includes core customer loads in determining if reinforcements of the system are necessary on a peak design day. Even with the interruptible customer loads removed, the southern Redmond system, being farthest from the existing high-pressure mains and regulation, consistently experiences low pressures during cold weather events.

Q. How will Cascade's customers benefit from the Redmond Project?

A. The new HP pipeline and regulator station will bring the southern Redmond distribution system above design criteria during peak usage and cold weather events. Additionally, this project allows for new commercial and residential growth occurring in the area. The Synergi diagrams below in Figures 11 and 12 illustrate the anticipated improvements to the Redmond system resulting from this project.

Planning Commission recently completed a Housing Grant Project for the Redmond Housing Needs Analysis and Buildable Lands Inventory, according to the analysis, approximately 7,000 housing units are needed over the next 20 years.

Figure 11. Synergi Model: Redmond – Current Model

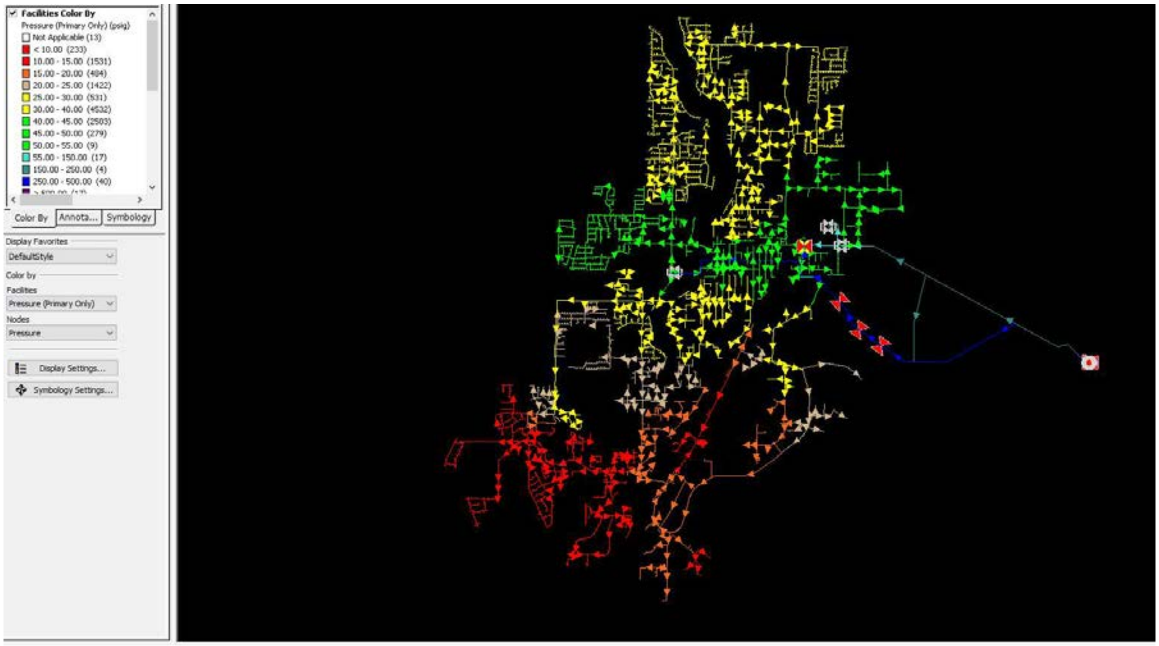
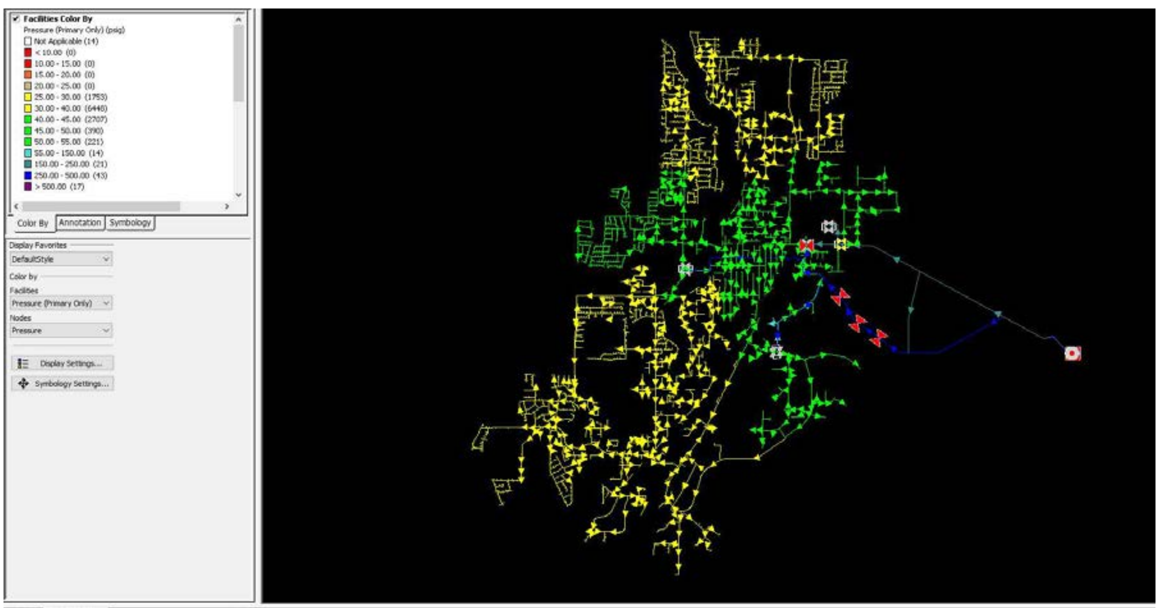


Figure 12. Synergi Model: Redmond – Improved Model Upon Project Completion



As indicated in the legends for both diagrams, the areas of the map in red and orange indicate pressures below 20 psig. Operating at pressures below 20 psig can result in outages especially during cold weather events. The improved model after the reinforcement is completed (Figure 12) shows these areas now operating at pressures above 20 psig (as shown by the yellow and green colors), therefore providing adequate pressure for new gas load and removing needs for remedial action during cold weather events.

Q. Did the Company consider alternative ways to address the need for system reinforcement in the Redmond area?

A. Yes, in addition to the Redmond Project as described above, the Company considered the following alternatives:

1. **No reinforcement:** Under this alternative, the Company would not perform any reinforcement.
2. **Postponing reinforcement:** Under this alternative, Cascade would postpone reinforcement for 2 years.
3. **Shorter reinforcement:** Under this alternative, Cascade considered making the new pipe installation shorter (2,000 feet), which would put the high-pressure system and regulator station farther from the existing and new load.

Q. Why did Cascade reject these alternatives and select the Redmond Project as the best way to meet the Company's needs in the Redmond area?

A. None of the alternatives that the Company considered would adequately meet the Company's need to provide reliable service in the Redmond area.

The Company determined that it could not pursue the first alternative (no reinforcement) because the southern Redmond distribution system would continue to experience low pressures during peak usage and cold weather events, and by not installing a reinforcement, Cascade would be unable to provide gas service to new residential and commercial customers and existing customers wanting to increase their commercial gas load in the southern Redmond distribution system.

The Company determined that it could not pursue the second alternative (postponement) because residential and commercial growth is occurring in the City of

Redmond currently and growth is anticipated to continue to increase. By not bringing higher pressure and regulation closer to the load, Cascade would not have the ability to provide service to new residential and commercial customers and existing customers wanting to increase their commercial gas load in the southern Redmond distribution system. Moreover, it is more efficient and cost-effective to install gas main while developments and construction are in progress, and it can be more difficult and expensive to install gas main and services at a later date when the system capacity is increased and new neighborhoods are built out with finished infrastructure (roads, sidewalks, storm, sewer, water, phone, cable, and power).

The Company determined that it could not pursue the third alternative (shorter reinforcement) because the Synergi modeling for this option showed some improvements in the southern Redmond distribution system, but did demonstrate adequate reinforcement for the remaining areas experiencing low pressure and did not provide adequate reinforcement to accommodate requests for additional load.

As a result, the Company determined that the Redmond Project was the best option to meet the Company's need for reinforcement in the area and accommodate future growth.

Q. Was the Redmond Project included in the Company's 2018 IRP?

A. No, the need for this project was not yet identified at the time the Company prepared its 2018 IRP. The analysis supporting this project will be included in the Company's 2020 IRP, which will be filed in July 2020.

Q. What is the timing of the project?

A. Design for the pipeline is currently underway, and construction is planned to begin April 2020. The Company estimates that the Redmond Project will be complete and in-service by May 2020.

Q. What are the estimated costs of the Redmond Project?

A. The estimated costs for the total project, including pipeline and regulator station, are summarized below:

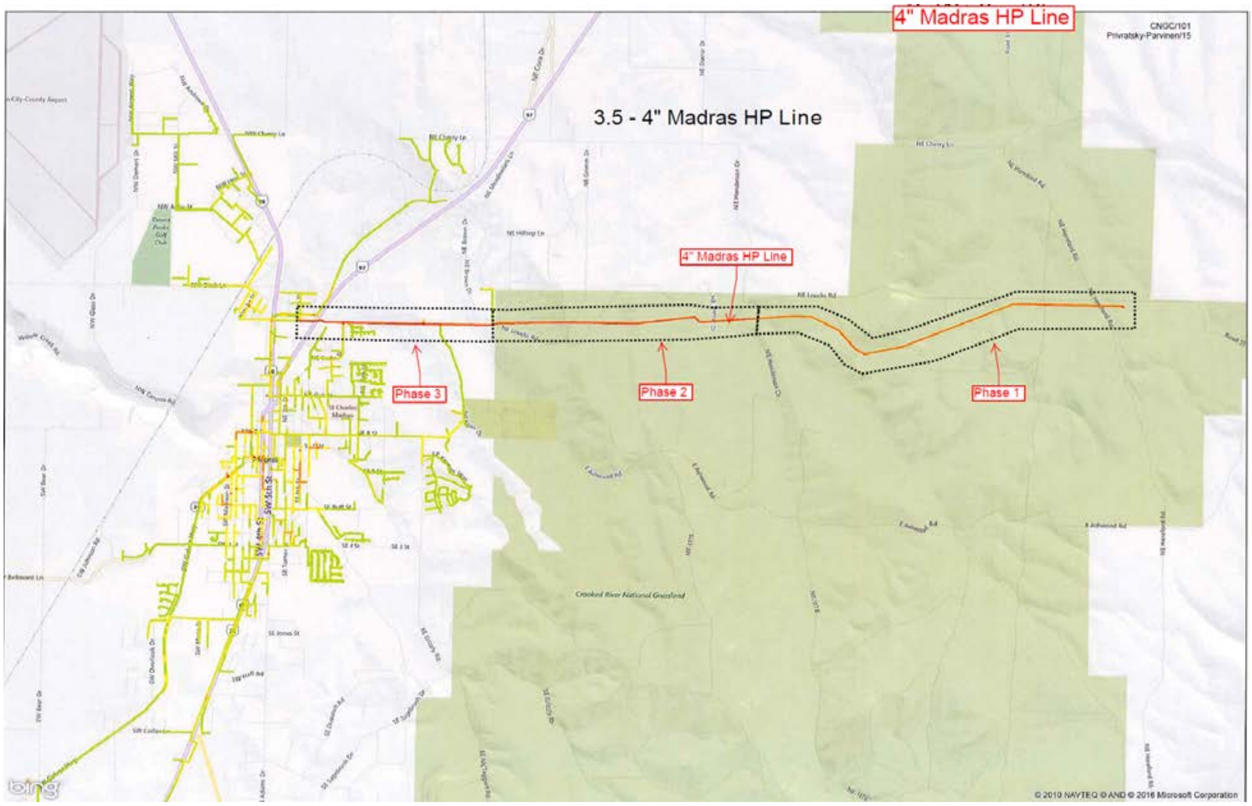
Materials	$	193,755.58
CNGC Labor	$	45,076.02
Contractor Costs	$	919,455.43
Resources	$	42,009.00
Total Direct Costs	**$**	**1,200,296.03**
Corporate Overhead	**$**	**176,203.46**
Total Estimated Project Costs	**$**	**1,376,499.49**

F. Madras Phase 3

Q. Please describe the Madras HP Replacement Project.

A. The Madras HP Replacement Project is a multi-year, HP pipeline replacement project. The existing 4" Madras High-Pressure ("HP") Line ("Madras Line") was installed in 1962 from the Madras Gate Station, east of Madras near NE Loucks Road and NE Hereford Road, and runs through the Crooked River National Grassland, until it terminates in Madras. The Madras HP Replacement Project will replace the existing 4" steel installed in 1962 with a new 6" steel pipeline. The overall replacement project area is shown on the map below in Figure 13.

Figure 13. Madras HP Replacement Project



Q. Why is the Company undertaking the Madras HP Replacement Project?

A. The Company's Subject Matter Experts ("SMEs") in the Bend District have identified multiple integrity concerns for the Madras Line, including a history of multiple seam leaks resulting in leak repairs, two electrically shorted casings, poor quality of welds that have been exposed, shallow depth of cover, poor existing backfill and trench conditions where pipe was installed in rock with no padding, and insufficient material and construction records.

Q. What work was performed in prior phases of the Madras HP Replacement Project?

A. The Madras HP Replacement Project began in 2017. Phase 1 was completed in September of 2018 and replaced the pipe from the Madras Gate Station to Regulator Station R-75. Phase 2 was completed in 2019 and consisted of replacing pipe from Regulator Station R-75 to Regulator Station R-74.

Q. What work will be performed in Phase 3 of the Madras HP Replacement Project?

A. The final phase, Phase 3 is planned for 2020 and will replace pipe from Regulator Station R-74 to Regulator Station R-19.

Q. How will this project benefit customers?

A. The Madras HP Replacement Project increases the safety and reliability of the Company's pipeline system in the Madras area by replacing a single feed with known integrity concerns.

Q. Did the Company consider alternative ways to meet the need for this project?

A. No other alternatives adequately addressed the pipeline safety integrity risk or continued to provide the capacity needs for the City of Madras that this pipeline provides.

Q. What is the timing of the Madras Phase 3 Project?

A. Design is near complete and construction is estimated to begin early summer with an anticipated in-service date of November 2020.

Q. What are the estimated costs of the Madras Phase 3 Project?

A. The Madras Phase 3 Project is anticipated to cost $1,950,000.

IV. BLANKET FUNDING PROJECTS

Q. Please describe the Company's use of "blanket" funding for capital projects.

A. Blanket funding is used for certain types of capital work that historically occurs every year but is not specifically known at time of budgeting. Examples of blanket funding projects include: 1) replacement of regulator stations due to location, damage or capacity; 2) new regulator stations due to growth; and 3) distribution pipe replacement projects in city, state or county roadways due to road widening projects. Replacement of pipe in roadways is heavily dependent upon funding from various state and federal agencies and it is not known what projects may be required or how much funding will be available from these agencies at the time the Company creates its capital budget. Work Orders are created within a Funding Project that are estimated at less than $100,000. Work Orders greater than $100,000 require their own Funding Project number.

Q. How does the Company budget for blanket funding?

A. The Company reviews certain types of capital work that historically occurs each year in each state and also communicates with some local governing agencies to help determine what projects are planned and/or scheduled locally. The Company would then estimate a reasonable budget cost for each state based on current known or scheduled work and historical average annual costs.

Q. In total, how much of the Company's Oregon capital budget is attributable to blanket funding projects?

A. Out of the Company's Oregon capital budget of $22.1 million, approximately $13 million is attributable to blanket funding projects.

V. CUSTOMER CARE AND BILLING SYSTEM UPGRADE

Q. Please describe the Company's Customer Care and Billing System Upgrade ("CC&B Upgrade").

A. Currently the Utility Group is running Oracle's Customer Care & Billing ("CC&B") v2.4 as its Customer Information and Billing System. This project involves upgrading the CC&B to a newer version, v2.6. This is primarily a technical upgrade to the base architecture of CC&B.

Q. Why is the Company performing the CC&B Upgrade?

A. We are in the process of preparing the billing system for the next version of Oracle CC&B. Our current version of CC&B is written in COBOL which is an outdated application development language. The majority of our custom modules were also written in COBOL when CC&B was implemented. We are converting these modules into Java which is a modern high-level programming language that is primary used for creating web-based applications. The next version of CC&B will only support Java modifications thus, we need to convert our COBOL custom modifications to the Java platform. This will be accomplished as an "In-place upgrade," which means we will deploy the new code into our existing environment while we test it in both v2.4 and v2.6 environments thus greatly reducing the time it will take to do actual CC&B version changes later. In addition to the code changes, we will be re-configuring all the billing rates in the system since v2.6 introduces a new rate engine methodology.

Q. Did the Company consider alternatives to the CC&B Upgrade?

A. There were no other options available to us unless we no longer wish to stay current with the vendor's upgrade cycle. As a result, Cascade decided to pursue the upgrade to keep current with the vendors version releases in order to take advantage of new features and functions, continued vendor technical support and, more importantly, vendor security patch management.

Q. How will customers benefit from the CC&B Upgrade?

A. Customer benefits will include continual access to future enhancements, improved performance, continual vendor support and security patches that protect their personally identifiable information data.

Q. What is the total cost for the CC&B Upgrade?

A. On an Oregon-allocated basis, the total cost of the CC&B Upgrade is estimated to be $255,481.71.

Q. When will the CC&B Upgrade be complete?

A. The current plan is to go into production with the CC&B upgrade in May 2020.

Q. Does this complete your direct testimony?

A. Yes, it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 390

Cascade Natural Gas Corporation

Direct Testimony of Maryalice C. Peters

EXHIBIT 300

March 31, 2020

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 West Grandridge Blvd., Kennewick, Washington 99336-7166. My e-mail address is maryalice.peters@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 a Regulatory Analyst III in the Regulatory Affairs Section. Among my duties, I am responsible for preparing Cascade’s regulatory reports, tariff and compliance filings, and other regulatory filings that are filed with the Public Utility Commission of Oregon (“Commission”) and Washington Utilities and Transportation Commission (“WUTC”). I also provide regulatory advice and knowledge to others within the Company.

Q. How long have you been employed by Cascade?

A. I have been employed by the Company since December 2010.

Q. Please state your educational and professional qualifications.

A. I graduated from the Washington State University in 2009, receiving a Bachelor of Arts degree in Management and Operations. Since joining Cascade, I have attended several regulatory courses and conferences, including the American Gas Association regulatory studies program held at the University of Chicago in 2012, 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 previously filed testimony on the Company's natural gas revenue requirement before this Commission in Docket UG 347, and before the WUTC in Dockets UG-170929 and UG-190210.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present the Company's calculation of the revenue requirement increase requested in this proceeding.

Q. Please summarize Cascade's requested net revenue change.

A. The Company is seeking to increase revenues from base rates by $4,507,842 for its Oregon service territory plus an additional $363,765 for increased amortization of environmental remediation expense associated with the Eugene Environmental Remediation Site ("Environmental Remediation"). The combined increase to base rates and increased amortization for Environmental Remediation expense results in a 7.209 percent increase to revenues collected from customers.

As shown in Exhibit CNGC/301, without the requested increase in base rates, Cascade's natural gas operations would expect to earn a return of only 4.68 percent in the 2020 Test Year ("Test Year"), well below the Company's authorized rate or return ("ROR") of 7.08 percent. Therefore, the Company needs to increase its rates in order to allow the opportunity to earn a reasonable return and to allow the Company to attract capital essential for operating the utility for the benefit of its customers.

Q. Do you sponsor any exhibits in support of the Company's proposal in this proceeding?

A. Yes, I sponsor the following exhibits in support of 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 2020 Plant Additions
- Exhibit CNGC/306 Calculation of Rate for Schedule 197, Environmental Remediation Cost Adjustment

III. <u>REVENUE REQUIREMENT</u>

Q. What is the purpose of this section of your testimony?

A. In this portion of my testimony, I describe the Company's financial results for its Oregon operations for the Test Year.

Q. What period is included in the Company's Test Year for this case?

A. The Test Year in this case is the 12 months ending December 31, 2020.

Q. What period is included in the Company's Base Year?

A. The Base Year in this case is the 12 months ending December 31, 2019.

Q. Why was the twelve months ended December 31, 2019, chosen as the Base Year?

A. This period was chosen because it provided a full calendar year of accounting information and provided the most recent available data for the preparation of our rate case.

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 2021, Cascade is opting to keep this filing as simple as possible by excluding such projections.

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

A. Exhibit CNGC/301 presents Cascade's results of operations for the Test Year. Cascade anticipates that, after accounting for the adjustments shown in Exhibit CNGC/301, it would achieve a ROR of 4.68 percent. The incremental revenue necessary to achieve the Company's currently authorized ROR of 7.08 percent is $4,507,842, as shown in Exhibit CNGC/301.

The figures shown in Exhibit CNGC/301, column (1) are the actual Oregon booked figures for the Base Year. Column (2) is the summation of all adjustments, both restating and forecasted, to achieve the Test Year results. Each adjustment that is included in column (2) is identified separately in Exhibit CNGC/304, Proposed Adjustments to Base Year Results, 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 Year absent any rate change. Column (4) identifies the proposed revenue change and the net income impact of the revenue increase. The calculation of the incremental revenue is also provided in Exhibit CNGC/302. Column (5) is the results of operation expected during the Test Year with proposed rates.

Q. What is your total revenue requirement?

A. Our total revenue requirement is $72,086,038, which includes the proposed revenue increase of $4,507,842 necessary to achieve the Company's authorized rate of return of 7.08 percent. The proposed increase of $4,507,842 results in an overall base revenue increase of 6.67 percent. The Company's calculation of its revenue requirement is found in Exhibit CNGC/302.

IV. <u>ADJUSTMENTS AND SUPPORTING CALCULATIONS</u>

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I describe the adjustments Cascade has made to the Base Year results to annualize, remove, and include known and measurable changes expected to occur during the Test Year. I have prepared an explanation for each adjustment and describe the net effect of these adjustments.

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

A. This figure is the total operation revenues from Exhibit CNGC/301, column (3), line 4.

Q. Please explain the conversion factor used in this filing.

A. The conversion factor is used to adjust the natural gas net operating income deficiency for revenue sensitive items and taxes to determine the total natural gas requested net revenue change. The revenue sensitive items and taxes are uncollectibles, franchise fees, Commission fees, Oregon state income tax, and federal income taxes. The conversion factor is 0.70584 for natural gas operations, as shown on Exhibit CNGC/303.

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

A. Yes. Exhibit CNGC/304 presents the impact of each of the adjustments being made to the results of operations for the Base Year. 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 $1,130.

Column (b), entitled “Removal 50% Membership Fees” adjusts 50 percent 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 $34,435.

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.[1]

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

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 $5,634.

Column (d), entitled “Interest Coordination Adjustment” adjusts federal income taxes for the effect of the average long-term debt rate used to calculate the ROR applied to the proposed rate base as 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 a decrease in net income of $185,802.

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 $907,676 during 2018, 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 $662,567.

Column (f), entitled “Annualizing Wage Rate Adjustment” reflects the full year impact for 2019 of the union contract wage increase that was effective April 1, 2019. This adjustment reduces net income by $20,851.

Column (g), entitled “2020 Revenue Adjustment’ adds margin revenue to account for the additional customers at weather normalized loads to be added during 2020. This adjustment reflects final rates authorized in docket UG 347 on projected loads, which increases net income by $359,222.

Column (h), entitled “2020 Wage Adjustment” reflects the actual wage adjustment applied to non-union and union employees. The non-union wage increase was four percent and was effective January 1, 2020. The union increase was three percent and is effective on April 1, 2020. This adjustment decreases net income by $168,365.

Column (i), entitled “Incentive Comp Adj” removes all incentive compensation paid to the executive group. This adjustment also removes 50 percent of non-officer incentives based on non-financial metrics. This adjustment is consistent with the Type I adjustment in Cascade’s annual earnings report. The result is an increase in net income of $484,599.

Column (j), entitled “2020 Plant Additions” provides the Company’s board approved budgeted level of capital additions expected to go into service during 2020. Many 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. In fact, several projects have been updated in the testimony of Mr. Darras that will be reflected later in the case. The starting point for the plant addition adjustment is the approved capital budget. The net income effect of the rate base additions, for depreciation expense and property taxes, is a decrease of $719,316. The rate base impact is an increase of $21,367,038.

Column (k), entitled “Inflation Factor Adj” shows the impact of applying a consumer price index inflation factor to non-labor related expenses. The net income effect is a decrease of $106,842.

Column (l), entitled “Depreciation Expense Adj” shows the impact of the new proposed depreciation rates in the Company’s depreciation study filed on March 26, 2020, in Docket UM 2073. Cascade’s previous depreciation study was filed in Docket UM 1727 and resulted in depreciation rates effective January 1, 2016. The impact of applying the authorized depreciation rates from UM 1727 to actual plant balances as of December 31, 2019, is $703,112 and then applying the new proposed depreciation rates results in a monthly increase of $22,365. In sum, the adjustment results in an increase to depreciation expense of $725,477. This results in a decrease to net income of $680,859.

Column (m), entitled “A&G Adjustment” removes certain miscellaneous administrative and general expenses that are not appropriate for recovery through customer rates. To develop its response for Standard Data Request 57 and determine booked expenses that are inappropriate for rate recovery, Cascade performed an analysis for Non-Labor costs recorded in all FERC accounts for the Base Year. This adjustment increases net income by $4,712.

Column (n), entitled “Rate Case Costs” reflects the impacts of incremental costs associated with filing this general rate case and includes the remaining previous rate case expenses yet to be collected. These costs will be updated later in the case as they become known and better estimated. The net income impact is a decrease of $129,973.

Column (o), entitled “D&O Insurance Premiums” removes 50 percent of all levels of Director and Officer Liability insurance premiums, resulting in an increase of $11,585 to net income.

Column (p), entitled “Special Contracts” is an adjustment placeholder for an anticipated contract agreement, to be filed in an upcoming application during this proceeding, between the Company and a firm distribution transportation service customer.

V. 2020 PLANT ADDITIONS

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

A. Yes. Cascade’s 2020 plant additions account for $3,160,817 of the total revenue requirement increase of $4,507,842—which is approximately 70 percent of the proposed increase.

Q. What plant additions are planned for 2020?

A. A list of all the projects planned for 2020, which includes a brief project description and cost estimates, are shown in Exhibit CNGC/305. These projects, cost estimates, and schedules are from the approved capital budget and will be updated to only include actual costs and projects in service by the end of 2020 as they become known. Company witness Patrick Darras provides a detailed explanation and support for the Company’s major capital additions and includes any updated information on individual projects that is known since the capital budget was approved.

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

A. Yes. The rate effective date in this case is February 1, 2021, and the projects included in Exhibit CNGC/305 are all scheduled to be completed and in-service by the end of 2020--one month prior to the rate effective date.

VI. <u>EUGENE ENVIRONMENTAL REMEDIATION</u>

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. Cascade, along with PacifiCorp and EWEB performed initial studies to determine cleanup project objectives, with oversight from the Oregon Department of Environmental Quality ("DEQ"). In January 2015, the DEQ issued a Record of Decision ("ROD") identifying the measures to remediate the site.[2]

The total remediation project consists of primarily four phases: investigation, design, remediation, and long-term management of the site. The investigation and design phases have been completed, and the actual remediation is almost completed. The completion date has been delayed due to cold weather at the end of 2019 and beginning of 2020, but the Company

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

anticipates the completion of remediation by summer 2020. After the remediation activities are complete, inspection and maintenance of the remedy is critical for ensuring that the long-term objectives for the constructed remedy are being met. A Site Management Plan ("SMP") is being developed which will describe the best management practices, inspection frequency, procedures and protocols necessary to ensure the long-term integrity and function of the remedial actions completed under the ROD.

Q. Is Cascade wholly responsible for the costs associated with the Eugene Remediation Site?

A. No. Cascade entered into a cost sharing agreement with two other responsible parties, EWEB and PacifiCorp. As provided in the cost sharing agreement, Cascade is responsible for 50 percent of the costs for all investigation, remedial design, and remediation. Cascade is also pursuing recovery from its insurance provider to help offset Cascade's share of the costs.

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.[3]

---

[3] 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*

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

A. Yes. In Cascade's last general two rate cases, Dockets UG 305 and UG 347, the settlements 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 settlements in its prior rate cases 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 $0.000303 per therm.

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.

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

Remediation, Docket No. UM 1636, Order No. 19-427 (Dec. 6, 2019) (most recent order approving Cascade's request for reauthorization of deferred accounting for environmental remediation expenses).

A. Yes. In total Cascade has received just over $377,000 of insurance proceeds through February 2020 related to the investigation phase of the project. The insurance proceeds are also included in the net deferred balance. Although no insurance proceeds were available for the design phase of the remediation project, Cascade is currently working to determine the best strategy to recover costs associated with 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 be approximately $1.5 million prior to the application of any additional 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 estimated to be $84,858 by the February 1, 2021, effective date of this case, with the incremental deferred balance accruing since the last rate case, which is approximately $1 million. This total estimated balance of $1,167,812 will be amortized over three years, which is consistent with the approach applied in the last two rate cases. The Company proposes to update Schedule 197 to reflect a three-year amortization of the total balance, collecting $401,530 per year. These figures and the calculation of the amortization rate are shown in Exhibit CNGC/306.

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. However, the total revenue increase from customers reflects both the change in revenue requirement and the increase associated with the change in the amortization rate for Environmental Remediation Amortization.

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

A. Schedule 197 is proposed to increase from $0.000303 per therm to $0.00322 per therm for the existing tracker, as shown in Exhibit CNGC/306.

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

A. Yes, Cascade expects to continue to defer additional costs for future recovery, which include the remediation work performed through summer 2020, on-going costs associated with monitoring and reporting, and costs associated with litigating the insurance provider’s obligations for the site. While Cascade does not anticipate significant additional costs, Cascade does propose to continue the deferral in order to capture these costs and to also capture future insurance proceeds for the benefit of customers.

Q. Does this conclude your testimony?

A. Yes.

CNGC/301
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

MARYALICE C. PETERS
Exhibit No. 301

Results of Operation Summary Sheet

Cascade Natural Gas Corporation
RESULTS OF OPERATION OF SUMMARY SHEET
UG 390
Twelve Months Ended December 31, 2019

	SUMMARY SHEET	2019 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	62,668,726	268,828	62,937,554	4,507,842	67,445,396
2	Gas Transportation Revenue	4,432,276	238,781	4,671,057		4,671,057
3	Other Operating Revenues	(30,415)	0	(30,415)		(30,415)
4	SUBTOTAL	67,070,587	507,609	67,578,196	4,507,842	72,086,038
5	LESS: Nat. Gas/Production Costs	31,489,133	(907,676)	30,581,457		30,581,457
6	placeholder	0	0	0		0
7	**OPERATING MARGIN**	35,581,455	1,415,285	36,996,740	4,507,842	41,504,581
	Operating Expenses					
8	Production	110,977	1,998	112,974		112,974
9	Distribution	6,651,691	59,116	6,710,807		6,710,807
10	Customer Accounts	1,907,206	34,510	1,941,716	15,357	1,957,073
11	Customer Service	307,924	0	307,924		307,924
12	Sales	2,074	(7,718)	(5,644)		(5,644)
13	Administrative and General	6,254,289	(245,178)	6,009,112		6,009,112
14	Depreciation & Amortization	7,772,990	1,664,373	9,437,362		9,437,362
15	Regulatory Debits	0	0	0		0
16	Taxes Other Than Income	5,734,175	267,549	6,001,723	122,271	6,123,994
17	State & Federal Income Taxes	191,406	88,759	280,165	1,180,133	1,460,298
18	**Total Operating Expenses**	28,932,731	1,863,409	30,796,140	1,317,760	32,113,900
19	**Net Operating Revenues**	6,648,724	(448,124)	6,200,600	3,190,082	9,390,681
	Rate Base					
20	Total Plant in Service	254,933,050	22,119,221	277,052,271		277,052,271
21	Total Accumulated Depreciation	(109,428,349)	(9,437,362)	(118,865,711)		(118,865,711)
22	Contributions in Aid of Construction	0	0	0		0
23	Customer Adv. For Construction	(440,037)	0	(440,037)		(440,037)
24	Deferred Accumulated Income Taxes	(27,470,311)	(20,545)	(27,490,856)		(27,490,856)
25	Deferred Debits		0	0		0
26	Working Capital Allowance	2,358,018	0	2,358,018		2,358,018
27	**TOTAL RATE BASE**	119,952,371	12,661,313	132,613,684	0	132,613,684
28	**Rate of Return**	5.54%		4.68%		7.08%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

MARYALICE C. PETERS
Exhibit No. 302

Revenue Requirement Calculation

Cascade Natural Gas Corporation
REVENUE REQUIREMENT CALCULATION
UG 390
Twelve Months Ended December 31, 2019

1	Adjusted Rate Base	$132,613,684
2	Rate of Return	7.08%
3	Required Return (ln 1 x ln 2)	$9,382,418
4	Adjusted Net Income	$6,200,600
5	Required Net Income Increase (ln 3 - ln 4)	$3,181,819
6	Conversion Factor	0.70584
7	Revenue Increase Required (ln 5 / ln 6)	**$4,507,842**
8	Test Year Adjusted Revenue	$67,578,196
9	Overal Revenue Increase	**6.671%**
10	Exh. 306 Environmental Rem. Revenue Increase	$ 363,765
11	Total Revenue Increase	$4,871,607
12	Total Increase	7.209%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

MARYALICE C. PETERS
Exhibit No. 303

Conversion Factor Calculation

Cascade Natural Gas Corporation
CONVERSION FACTOR CALCULATION
UG 390
Twelve Months Ended December 31, 2019

1	Revenues	1.00000
2	Operating Revenue Deductions	
3	Uncollectible Accounts	0.00341
4	Taxes Other - Franchise	0.02412
5	OPUC Fees	0.00300
6	Interest expense	
7	State Taxable Income	0.96947
8	State Income Tax	0.07600
9	Federal Taxable Income	0.89347
10	Federal Income Tax @ 21%	0.18763
11	Total Income Taxes	0.26363
12	Total Revenue Sensitive Costs	0.29416
13	Net-to-Gross Factor	**0.70584**
14	Combo-State & Federal Income Tax	
15	State	0.07600
16	Federal	0.21000
17	State and Federal Effective Tax Rate	0.27004

CNGC/304
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

MARYALICE C. PETERS
Exhibit No. 304

Proposed Adjustments to Base Year Results

Cascade Natural Gas Corporation
PROPOSED ADJUSTMENTS TO BASE YEAR RESULTS
UG 390
Twelve Months Ended December 31, 2019

		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)	2020 Revenue Adjustment (g)	2020 Wage Adjustments (h)	Incentive Comp Adj (i)	2020 Plant Additions (j)	Inflation Factor Adj (k)	Depreciation Expense Adj (l)	A&G Adjustment (m)	Rate Case Costs (n)	D&O Insurance Premiums adj (o)	Special Contracts adj (p)	**Total Adjustments (Base Rates) (q)**
1	**Operating Revenues**																	
2	Natural Gas Sales							$268,828				$0	$0	$0				268,828
3	Gas Transportation Revenue							238,781				0	0	0				238,781
4	Other Operating Revenues											0	0	0				0
5	SUBTOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$507,609**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$507,609**
6	LESS: Nat. Gas/Production Costs					(907,676)												($907,676)
7	placeholder					0												$0
8	**OPERATING MARGIN**	**$0**	**$0**	**$0**	**$0**	**$907,676**	**$0**	**$507,609**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	$1,415,285
9																		$0
10	**Operating Expenses**																	$0
11	Production											1,998						$1,998
12	Distribution											59,116						$59,116
13	Customer Accounts	($1,549)				$0		$1,729				34,330						$34,510
14	Customer Service											0						$0
15	Sales			(7,718)														($7,718)
16	Administrative and General		(47,174)				28,565		230,650	(663,871)		50,923		(6,455)	178,055	(15,870)	0	($245,178)
17	Depreciation & Amortization										731,637		932,735					$1,664,373
18	Regulatory Debits																	$0
19	Taxes Other Than Income							13,768			253,780							$267,549
20	State & Federal Income Taxes	418	12,739	2,084	185,802	245,109	(7,714)	132,890	(62,285)	179,272	(266,102)	(39,525)	(251,876)	1,743	(48,082)	4,286	0	$88,759
21	**Total Operating Expenses**	(1,130)	(34,435)	(5,634)	185,802	245,109	20,851	148,387	168,365	(484,599)	719,316	106,842	680,859	(4,712)	129,973	(11,585)	0	$1,863,409
22	**Net Operating Revenues**	$1,130	$34,435	$5,634	($185,802)	$662,567	($20,851)	$359,222	($168,365)	$484,599	($719,316)	($106,842)	($680,859)	$4,712	($129,973)	$11,585	$0	($448,124)
24	**Rate Base**																	
25	Total Plant in Service										22,119,221							$22,119,221
26	Total Accumulated Depreciation										(731,637)		(8,705,725)					($9,437,362)
27	Contributions in Aid of Construction																	$0
28	Customer Adv. For Construction																	$0
29	Deferred Accumulated Income Taxes										(20,545)							($20,545)
30	Deferred Debits																	$0
31	Working Capital Allowance																	$0
32	**TOTAL RATE BASE**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$21,367,038	$0	($8,705,725)	$0	$0	$0	$0	$12,661,313
33																		
34	**Revenue Requirement Effect**	**($1,601)**	**($48,786)**	**($7,982)**	**$263,235**	**($938,692)**	**$29,541**	**($508,927)**	**$238,531**	**($686,556)**	**$3,160,817**	**$151,368**	**$91,989**	**($6,675)**	**$184,139**	**($16,412)**	**$0**	**$1,903,988**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

MARYALICE C. PETERS
Exhibit No. 305

2020 Plant Additions

Cascade Natural Gas Corporation
2020 PLANT ADDITIONS
UG 390
Twelve Months Ended December 31, 2019

Line No.	Function	Description	Account No.	2020 Total - Figures exported from "Power Plan" the company's budget and plant accounting software	OR Alloc	OR
1	Gas Intangible	FP-200064 UG-Customer Self Service Web/IVR	303.00	178,531.96	24.83%	44,329.49
2	Gas Intangible	FP-200663 UG-GIS Enhancements	303.00	87,032.79	24.83%	21,610.24
3	Gas Intangible	FP-302621 UG-LV Customer Website-CNG	303.00	50,930.43	24.83%	12,646.03
4	Gas Intangible	FP-316019 UG-GIS ESRI System Upgrade	303.00	346,857.72	24.83%	86,124.77
5		FP-316047 UG-GIS Landbase Repl and Enhanc	303.00	315,348.35	24.83%	78,301.00
6	Gas Intangible	FP-316102 UG-GIS Pipeline Inspection System	303.00	158,747.54	24.83%	39,417.01
7	Gas Intangible	FP-316182 UG-CC&B Upgrade to 2.6+	303.00	1,028,923.52	24.83%	255,481.71
8	Gas Intangible	FP-316284 GIS High Acc Trans Line Surv Enhanc	303.00	155,972.76	24.83%	38,728.04
9	Gas Intangible	FP-316361 UG-GAS SCADA System Enhancements	303.00	69,223.05	24.83%	17,188.08
10	Gas Intangible	FP-317617 UG-Migrate Aligne CNG Direct	303.00	8,476.31	24.83%	2,104.67
11	Gas Intangible	FP-317101 UG-JDEdwards AS400 to Oracle DB	303.00	63,738.72	24.83%	15,826.32
12	Gas Intangible	FP-318822 Impl myWorld Leak Survey-CNG	303.00	5,492.14	24.83%	1,363.70
13	Gas Intangible	FP-318846 UG-Impl 2Ring Dashboard for CSC-CNG	303.00	26,509.60	24.83%	6,582.33
14	Gas Intangible	FP-318893 UG-Impl GIS Offline Mobile Maps-CNG	303.00	27,529.20	24.83%	6,835.50
15		**Total Intangible Plant**		2,523,314.09		626,538.89
16	RESULTS OF OPERATIONS SUMMARY SHEET					
17	Gas Distribution	FP-101170 MAIN-GROWTH-OREGON	376.30	642,990.10		642,990.10
18	Gas Distribution	FP-101171 MAIN-REINFORCE-OREGON	376.10	23.44		23.44
19	Gas Distribution	FP-101172 MAIN-RELO-REPL-OREGON	376.10	15,952.83		15,952.83
20	Gas Distribution	FP-101175 R STA-RELO-REPL-OREGON	378.00	7,978.81		7,978.81
21	Gas Distribution	FP-101177 SERV-RELO-REPL-OREGON	380.30	38,600.78		38,600.78
22	Gas Distribution	FP-101180 IND M&R-GROWTH-OREGON	385.00	25,609.27		25,609.27
23	Gas Distribution	FP-101181 IND M&R-REMOVE&REPLACE-OREGO	385.00	1,711.29		1,711.29
24	Gas Distribution	FP-101210 Gas Meters-Total Company CNGC	381.00	3,919,185.28	24.83%	973,133.71
25	Gas Distribution	FP-101259 Gas Regulators-Total Company CNGC	383.00	1,320,143.48	24.83%	327,791.63
26	Gas Distribution	FP-302370 Gas Cathodic Protection - OR	376.10	275,478.16		275,478.16
27	Gas Distribution	FP-306980 ERT Replacement 2020	381.00	363,466.80	24.83%	90,248.81
28	Gas Distribution	FP-306990 PENDLETON 4" IP REINFORCEMENT	376.30	-		0.00
29	Gas Distribution	FP-306991 PENDLETON 4" HP REINFORCEMENT	376.20	-		0.00
30	Gas Distribution	FP-312013 RP; REG STA R-9 Weston	378.00	-		0.00
31	Gas Distribution	FP-316432 RP; 2" BRIDGE XING, MILTON FREEWA	376.10	189,446.76		189,446.76
32	Gas Distribution	FP-316479 Bend River Mall Main RPL Bend	376.30	10,604.80		10,604.80
33	Gas Distribution	FP-316574 RPL; 4" HP, MADRAS PH3	376.20	2,066,432.99		2,066,432.99
34	Gas Distribution	FP-316575 MAOP; 12" HP; BEND; 5,500' PHASE 2	376.20	726,189.91		726,189.91
35	Gas Distribution	FP-316576 RPL; 6" HP, BEND HP PH3	376.20	1,800,952.04		1,800,952.04
36	Gas Distribution	FP-317586 RF-REDM-6"S-4,750'-VETERANS WY	376.20	1,295,377.66		1,295,377.66
37	Gas Distribution	FP-317660 MAIN-GROWTH-EASTERN OREGON DI	376.30	43,216.92		43,216.92
38	Gas Distribution	FP-317661 MAIN-REPL-EASTERN OREGON DISTR	376.30	153,389.44		153,389.44
39	Gas Distribution	FP-317662 SERV-GROWTH-EASTERN OREGON DI	380.30	146,926.20		146,926.20
40	Gas Distribution	FP-317663 SERV-REPL-EASTERN OREGON DISTR	380.30	74,576.30		74,576.30
41	Gas Distribution	FP-317664 MAIN-GROWTH-PENDLETON DISTRIC	376.30	280,881.48		280,881.48
42	Gas Distribution	FP-317665 MAIN-REPLACE-PENDLETON DISTRIC	376.30	153,389.44		153,389.44
43	Gas Distribution	FP-317666 SERV-GROWTH-PENDLETON DISTRIC	380.30	659,001.00		659,001.00
44	Gas Distribution	FP-317667 SERV-REPLACE-PENDLETON DISTRIC	380.30	74,576.30		74,576.30
45	Gas Distribution	FP-317754 MAIN-GROWTH-BEND DISTRICT	376.30	1,242,358.08		1,242,358.08
46	Gas Distribution	FP-317755 MAIN-REPLACE-BEND DISTRICT	376.30	153,389.44		153,389.44
47	Gas Distribution	FP-317756 SERV-GROWTH-BEND DISTRICT	380.30	2,538,751.44		2,538,751.44
48	Gas Distribution	FP-317757 SERV-REPLACE-BEND DISTRICT	380.30	74,576.30		74,576.30
49	Gas Distribution	FP-318091 HPSS Replacements CNG OR	376.30	772,070.00		772,070.00
50	Gas Distribution	FP-318099 Reg Station Growth CNG OR	378.00	593,900.00		593,900.00
51	Gas Distribution	FP-318174 Reg Station Replace CNG OR	378.00	188,170.00		188,170.00
52	Gas Distribution	FP-318184 Sys Safety & Integ Main Repl CNG OR	376.30	1,717,615.00		1,717,615.00
53	Gas Distribution	FP-318185 Sys Safety & Integ Svcs Rpl CNG OR	380.30	1,480,055.00		1,480,055.00
54	Gas Distribution	FP-318682 RF-BEND-6"S-1100'-SHEVLIN PK	376.20	772,070.00		772,070.00
55	Gas Distribution	FP-318684 RF-Umat-2" River Crossing	376.30	137,983.98		137,983.98
56	Gas Distribution	FP-318741 RF-BEND-6"PE-1200'-PONDEROSA ST	376.30	235,682.00		235,682.00
57	Gas Distribution	FP-318770 RF-REDM-R-VETERANS WAY-2" STD	378.00	130,658.00		130,658.00
58	Gas Distribution	FP-318785 GR-REDM-R-THORNBURG DEV-2"STD	378.00	1.00		1.00
59	Gas Distribution	FP-318790 GR-REDM-4"S-7.7MI-THORNBURG DEV	376.20	1.00		1.00
60	Gas Distribution	FP-319230 RP; 2" ST; BEND; 2,528' PH 8 SEC 2	376.30	155,849.25		155,849.25
61	Gas Distribution	FP-319231 RP; 3/4" SL; BEND; PH 8 SEC 2 A SER	380.30	52,653.41		52,653.41
62	Gas Distribution	FP-319249 Westgate Phase 1,2,3,4 NW MN Bend	376.30	73,130.31		73,130.31
63		**Total Distribution Plant**		23,590,516.20		20,393,394.27

Cascade Natural Gas Corporation
2020 PLANT ADDITIONS
UG 390
Twelve Months Ended December 31, 2019

Line No.	Function	Description	Account No.	2020 Total - Figures exported from "Power Plan" the company's budget and plant accounting software	OR Alloc	OR
64	Gas General	FP-101163 Gas Work Equipment-CNGC	396.20	481,087.24	24.83%	119,453.96
65	Gas General	FP-101164 IT Network Equipment-CNG	397.20	290,586.04	24.83%	72,152.51
66	Gas General	FP-101215 Gas Vehicles-CNGC	392.20	2,180,374.04	24.83%	541,386.87
67	Gas General	FP-200662 Personal Computers & Peripherals	391.30	54,854.48	24.83%	13,620.37
68	Gas General	FP-306967 District Office Access Control Sys	391.30	27,223.01	24.83%	6,759.47
69	Gas General	FP-316445 Toughbook Replacements-CNG	391.30	176,798.64	24.83%	43,899.10
70	Gas General	FP-316832 Office Structure & Eq-Kennewick GO	391.50	50,980.00	24.83%	12,658.33
71	Gas General	FP-316915 Pur replacement display devices	391.30	17,333.20	24.83%	4,303.83
72	Gas General	FP-317078 Itron Mobile Radio (IMR)-CNG	397.40	76,470.00	24.83%	18,987.50
73	Gas General	FP-317743 Tools & Minor Work Equip CNG OR	394.10	31,706.50		31,706.50
74	Gas General	FP-318192 Fixed Network Equipment-CNG	397.20	509,800.00	24.83%	126,583.34
75	Gas General	FP-318197 Gas SCADA Equipment-CNG	397.20	1,223.52	24.83%	303.80
76	Gas General	FP-318706 Repl Cisco VoIP Telephone-CNG	397.30	158,321.16	24.83%	39,311.14
77	Gas General	FP-318956 Upgrade transfer prover Bend	394.10	23,450.80		23,450.80
78	Gas General	FP-319043 Mueller Equipment	394.10	76,238.35	24.83%	18,929.98
79	Gas General	FP-319045 TAP TRUCK HYDRAULIC SYSTEM	394.10	11,422.98	24.83%	2,836.33
80	Gas General	FP-319048 Mueller Equipment	394.10	13,240.14	24.83%	3,287.53
81	Gas General	FP-319052 BUILDING UPGARDES	390.10	67,673.91	24.83%	16,803.43
82	Gas General	FP-319053 NEW WELDER YAK FAB SHOP	394.10	5,955.01	24.83%	1,478.63
83	Gas General	FP-319284 12" Mueller Shell Cutter and Stoppe	394.10	5,534.02	24.83%	1,374.10
84		**Total Distribution Plant**		4,260,273.04		1,099,287.54
85		**Total**		30,374,103.33		**22,119,220.69**

Line No.	FERC Acct	Budgeted 2020 Investment	Depr. Rate Order 15-315	Depreciation Expense	
86	**FERC**	**Budgeted 2020**	**Depr. Rate**	**Depreciation**	
87	**Acct**	**Investment**	**Order 15-315**	**Expense**	
88	303	626,538.89	10.00	62,653.89	
89	376.1	480,901.19	2.95	14,186.59	
90	376.2	6,661,023.60	1.39	92,588.23	
91	376.3	5,772,550.24	3.15	181,835.33	
92	378	920,707.81	1.97	18,137.94	
93	380.3	5,139,716.73	4.26	218,951.93	
94	381	1,063,382.51	2.72	28,924.00	
95	383	327,791.63	2.42	7,932.56	
96	385	27,320.56	1.87	510.89	
97	390.1	16,803.43	1.44	241.97	
98	391.3	68,582.78	44.02	30,190.14	
99	391.5	12,658.33	19.00	2,405.08	
100	392.2	541,386.87	5.89	31,887.69	
101	394.1	83,063.86	10.66	8,854.61	
102	396.2	119,453.96	9.63	11,503.42	
103	397.2	199,039.65	5.53	11,006.89	
104	397.3	39,311.14	21.62	8,499.07	
105	397.4	18,987.50	6.99	1,327.23	
106		22,119,220.69		731,637.46	0.033077

CNGC/306
Peters

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

MARYALICE C. PETERS
Exhibit No. 306

ENVIRONMENTAL REMEDIATION AMORTIZATION

Cascade Natural Gas Corporation
Environmental Remediation Amortization
UG 390
Twelve Months Ended December 31, 2019

3 Year Amortization of January 31, 2021 Balances		
UG 347 Balance to Amortize	$ 247,000	
Started Amortizing 4/1/2019		
Remaining Balance at January 1, 2021		$ 84,858
Current Deferred Balance from UM 1636		
Balance @ February, 2020 with interest		
through January 31, 2021		$ 1,082,954
Total to be amortized		$ 1,167,812
Three year Amortization		$ 389,271
Grossed up for Revenue Sensitive		$ 401,530

Schedule 197, Environmental Remediation Costs Adjustment Rate

Rate Class	Volumes
101	47,916,047
104	30,931,912
105	3,196,788
111	3,015,329
163	37,657,289
170	1,917,597
Total	124,634,962

Schedule 197 Rate $0.00322

$	0.000303	$ 37,764.39
$	0.00322	$ 401,529.62
Increase Rev		$ 363,765.22
		0.54%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 390

Cascade Natural Gas Corporation

Direct Testimony of Isaac D. Myhrum

EXHIBIT 400

March 31, 2020

EXHIBIT 400 – DIRECT TESTIMONY

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Isaac D. Myhrum. My business address is 8113 West Grandridge Blvd., Kennewick, WA 99336. My e-mail address is isaac.myhrum@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 a Regulatory Analyst II in the Regulatory Affairs Section. Among my duties, I am responsible for preparing regulatory reports, tariff and compliance filings, and other regulatory filings for Cascade that are filed with the Public Utility Commission of Oregon ("Commission") and the Washington Utilities and Transportation Commission ("WUTC"). I also provide regulatory advice and knowledge to others within the Company.

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 state your educational background and professional qualifications?

A. I graduated from the Washington State University with a Bachelor of Arts degree, in Business Administration with an emphasis in Accounting in 2014; and a Bachelor of Science degree in Political Science with an emphasis in Economics from the University of Idaho in 2005. Prior to joining the Company, I was employed as an Accountant for Nilson & Oord PLLC and Clifton Larsen Allen LLP public accounting firms.

Since joining Cascade, I have attended several regulatory courses and conferences, including Center for Public Utilities Rate School held at the New Mexico State University in 2016, as well as, other National Association of Regulatory Utility Commissioners sponsored events. I have previously filed testimony before this Commission in the Company's most recent rate case, Docket UG 347, and before the WUTC in Docket UG-190210.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present the Company's proof of revenue, margin per customer for the decoupling mechanism, and customer bill impacts associated with the rate increase proposed in this proceeding.

Q. Do you sponsor any exhibits in support of the Company's proposal in this proceeding?

A. Yes, I sponsor the following exhibits in support of my testimony:

- Exhibit CNGC/401 Proof of Revenue
- Exhibit CNGC/402 Calculation of Baseline Monthly Commodity Margin Per Customer

III. PROOF OF REVENUE

Q. What is the purpose of this section of your testimony?

A. This section of my testimony describes the Company's proof of revenue results for its Oregon operations.

Q. Would you please describe the Company's proof of revenue?

A. Yes. The Company's proof of revenue provides a comparison of revenues at current rates with revenues at the rates proposed in this case. Exhibit CNGC/401 presents the Company's per books revenue, in column D, for the twelve months ending December 31, 2019 ("Base Year"), broken out by rate schedule. 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 revenues total matches the 2019 total operating revenues subtotal presented in Company witness Maryalice Peters' testimony.[1] The test period in this case is the twelve months ending December 31, 2020 ("Test Year").

In order to provide an "apples-to-apples" comparison between current and proposed rates, Cascade adjusted per books revenue to true-up to future Test Year conditions, in column H. The revenue adjustment is derived by annualizing 2019 revenues to reflect the rate changes that were effective April 1, 2019, for rate schedules 101 (residential), 104 (commercial), 105 (industrial), 111 (large volume general service), 163 (transportation), and 170 (interruptible) and the rate changes that were effective November 1, 2019, for Special Contract rate schedules 902, 903, 904, and 905. Additionally, billing determinants (both 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 2019 revenue adjustment subtotal presented in Company witness Maryalice Peters' testimony.[2]

[1] CNGC/301, "2019 Results Per Company Filing" Column (1)
[2] CNGC/304, "2020 Revenue Adjustment" column (g), row 5 Subtotal

Both current and proposed rates are applied to these forecasted billing determinants for comparison purposes, in column J (current) and column L (proposed). The revenue impacts resulting from these changes, by rate schedule, are presented in column M. This final column represents the amount of the revenue increase or decrease required in rates for each customer class.

Q. Will you further describe the revenue adjustment in Column H?

A. Yes. As mentioned previously, changes to volumetric delivery and basic service charges went into effect for many Oregon customers on April 1, 2019. The rate revisions were the result of Company's last general rate case in Oregon.[3] In order to annualize 2019 revenues for the months after the rate revision of April 1, 2019, the associated billing determinants are adjusted up to future Test Year amounts. To achieve this restatement, the revenues from January through March 2019 are decremented from the per books revenue in column H and the revenues associated with the remaining months (*i.e.,* April through December 2019) are adjusted to proforma Test Year values. This is done by adjusting billing determinants to the forecasted number of bills and weather normalized volumes, then applying them to the respective basic service charges and volumetric rates effective April 1, 2019. The net effect of these calculations is the total revenue adjustment.

Q. What is shown in the Pro Forma section (Columns I & J) of the revenue proof?

[3] *See In the Matter of Cascade Natural Gas Corporation Application for a General Rate Revision*, Docket No. UG 347, Order No. 19-088 (March 14, 2019)

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

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. For most rate schedules, the forecasted volumes and number of bills (customers) used in this proof of revenue were produced by the Company's Integrated Resource Planning ("IRP") department and were based on the IRP projections available as of August 2019.

Q. Did the Company use any other inputs to forecast volumes?

A. Yes, for Rate Schedule 111 (Large Volume General Service), in addition to using the IRP projections from mid-2019, the Company also included projections for two new large volume customers, which were added after the initial forecast was modeled. By adding estimated volumes for these two large volume customers the Company was able to determine expected volumes for Rate Schedule 111 in 2020.

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

A. Yes. The use of the forecasted billing determinants forms the basis of an adjustment to the revenue requirement, which is addressed further in Company witness Maryalice Peters' testimony.[4]

[4] CNGC/300, PAGE 7 AT 20-23.

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 requirement increase the Company is requesting in this filing.

IV. DECOUPLING

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I provide an update on issues pertaining to the Company's Conservation Alliance Plan ("CAP" or "Decoupling Mechanism") and describe the Company's decoupling mechanism's allowed margin per customer for its Oregon operations.

Q. Please provide a brief overview of the Company's Decoupling Mechanism.

A. The Company's CAP Mechanism allows the Company to track changes in customer usage and revenues due to conservation and weather. The Company therefore maintains two deferral accounts within the mechanism, with the combined activities of schedules 101 (residential) and 104 (commercial) recorded. The first deferral account, related to conservation, records the difference of non-weather related margin from expected commodity margin. The second deferral account, related to weather, tracks differences in margin due to natural variances from normalized weather.

To arrive at the weather variation deferral, the Company multiplies a weather coefficient (which is calculated for each calendar month by Oregon weather zone) by the difference between weather-normalized Heating Degree Days (HDDs) and Actual HDDs and by the number of customers. The product is a therm value that is then multiplied by the Company's commodity margin rate (shown on the Company's tariff sheet as the delivery charge) to arrive at the weather variation deferral in dollars.

The conservation deferral is simply the difference between the expected commodity margin (number of customers multiplied by the baseline margin per customer) and weather variation deferral.

Historically, the Company has imputed interest on its CAP deferral accounts at its authorized rate of return, whereas Cascade's amortization accounts accrued interest at the Modified Blended Treasury ("MBT) Rates. Each year the deferral balances are transferred to an amortization account and are collected from or returned to customers at an annual rate based on forecasted therm values for Schedules 101 and 104.

Q. Did the Company recently review its Decoupling Mechanism?

A. Yes. In 2015, as part of the Stipulation in Docket UG 287, Cascade committed to initiate a review of its Decoupling Mechanism by September 30, 2019. Consistent with that commitment, on September 30, 2019, Cascade submitted an informational compliance filing[5] to begin that review process. The parties to Docket UG 287 were invited to participate in the review process, and the review process involved several meetings via conference calls, which occurred on October 18, 2019, November 1, 2019, and November 15, 2019. The parties also exchanged electronic communications and data files to share proposed changes. The parties who participated represented the Alliance of Western Energy

[5] UG 287 Oregon Decoupling Mechanism Review, Compliance Filing, September 30, 2019

Consumers ("AWEC"), the Oregon Citizens' Utility Board ("CUB"), Commission Staff and Cascade.

Q. What issues were considered by the parties during the review process?

A. The review centered on topics raised by parties in the Company's preceding general rate cases, UG 287, UG 305 and UG 347. These included topics such as non-linear computation of weather co-efficients, adjustments for new customers, a cap on the surcharge and interest accrual methods and rates.

Q. What changes were adopted for the Decoupling Mechanism?

A. In the Advice Filing No. 1071 submitted on November 27, 2019, Cascade proposed the following changes to its Decoupling Mechanism:

1. Implement an annual three percent CAP surcharge limit, with amounts in excess of three percent to be deferred to the next period. Previously there was no surcharge limit. Consistent with the existing practices, there is no cap on the amount of customer rebates.

2. Change the interest rate applied to CAP deferral balances from the Company's Authorizes Rate of Return to the MBT Rate, with any deferral amounts in excess of the three percent limit accruing interest at a rate equal to the Company's Authorized Rate of Return.

3. Provide that the Company will initiate a review of the CAP Mechanism on September 30, 2024, with any proposed changes to be effective January 1, 2025.

At the public meeting on December 17, 2019 the Commission adopted Staff's recommendation to support the changes as docketed in ADV 1071. The changes went into effect on January 1, 2020.

Q. Is the Company proposing any additional changes to its Decoupling Mechanism as part of this case?

A. No. Since the Company and stakeholders recently performed a review of the Decoupling Mechanism, and the changes resulting from that review have only been in effect for three months, the Company is proposing no additional changes to the Decoupling Mechanism at this time.

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/402 shows the allowed margin per customer.

Q. Please describe Exhibit CNGC/402 and how it will be used after the conclusion of this docket?

A. The monthly average margin per customer shown on Exhibit CNGC/402 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 in Docket No. ADV 1071.

Q. Does this conclude your testimony?

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

ISAAC D.
MYHRUM
Exhibit No. 401

Proof of Revenue

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	Therms/Bills Merge	Remove/Add 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)	(G)	(H) = (C)*(G)	(I) = (B)+(G)	(J) = (C)*(I)	(K)	(L) = (I)*(K)	(M) = (L)-(J)
1	**Rate Schedule 101 - General Residential Service**												
2	Basic Service Charge: Jan'19 - Mar'19	198,568	$4.00	$794,272			(198,568)	-$794,272					
3	Basic Service Charge: Apr'19 - Dec'19	592,955	$5.00	$2,964,776			219,494	$1,097,469	812,449	$4,062,245	$6.00	$4,874,694	
4	Delivery Charge: Jan'19 - Mar'19	23,008,471	$0.364070	$8,376,694			(23,008,471)	-$8,376,694					
5	Delivery Charge: Apr'19 - Dec'19	27,467,990	$0.369970	$10,162,332			20,448,057	$7,565,167	47,916,047	$17,727,500	$0.412460	$19,763,453	
6	Total Margin			$22,298,074				-$508,329		$21,789,745		$24,638,147	$2,848,402
7	Average Cost of Gas			$16,019,479									
8	Non-Gas Revenue												
9	Adjustment Dollars			-$78									
10	Franchise Tax			$861,310									
11	OR Unprotected Excess Deferred Income Tax			-$98,804									
12	CNG OR INTERIM PERIOD EDIT			-$150,426									
13	Public Purpose Fund R/S 31			$2,336,608									
14	PPC and Adjustments			-$4									
15	Subtract out PPC Fund & Adjustments			-$2,336,605									
16	Current Month Unbilled +			$24,856,757				-$24,856,757					
17	Previous Month Unbilled -			-$24,920,820				$24,920,820					
18	CAP Adjustment			-$2,056,561				$2,056,561					
19	Deferrals Revenue			$839,169				-$839,169					
20	Deficiency Billings			$0				$0					
21	Total Non-Gas Revenue			-$669,453				$1,281,455					
22	**Total Rate Schedule 101 Revenue**			**$37,648,100**				**$773,126**					
			check	$0									
23	**Rate Schedule 104 - General Commercial Service**												
24	Basic Service Charge: Jan'19 - Mar'19	30,697	$4.00	$122,788			(30,697)	-$122,788					
25	Basic Service Charge: Apr'19 - Dec'19	87,126	$10.00	$871,255			35,607	$356,075	122,733	$1,227,330	$12.00	$1,472,796	
26	Delivery Charge: Jan'19 - Mar'19	14,798,458	$0.262630	$3,886,519			(14,798,458)	-$3,886,519					
27	Delivery Charge: Apr'19 - Dec'19	18,719,123	$0.253770	$4,750,352			12,212,789	$3,099,240	30,931,912	$7,849,591	$0.267310	$8,268,409	
28	Total Margin			$9,630,914				-$553,993		$9,076,921		$9,741,205	$664,284
29	Average Cost of Gas			$10,534,803									
30	Non-Gas Revenue												
31	Adjustment Dollars			-$46,432									
32	Franchise Tax			$480,564									
33	OR Unprotected Excess Deferred Income Tax			-$41,006									
34	CNG OR INTERIM PERIOD EDIT			-$60,598									
35	Public Purpose Fund R/S 31			$1,231,543									
36	PPC and Adjustments			-$2,857									
37	Subtract out PPC Fund & Adjustments			-$1,228,686									
38	Current Month Unbilled +			$14,683,303				-$14,683,303					
39	Previous Month Unbilled -			-$14,567,161				$14,567,161					
40	CAP Adjustment			-$870,920				$870,920					
41	Deferrals Revenue			$584,303				-$584,303					
42	Deficiency Billings			$36,017				-$36,017					
43	Total Non-Gas Revenue			$198,071				$134,457					
44	**Total Rate Schedule 104 Revenue**			**$20,363,788**				**-$419,536**					
			check	$0									
45	**Rate Schedule 105 - General Industrial Service**												
46	Basic Service Charge: Jan'19 - Mar'19	442	$12.00	$5,304			(442)	-$5,304					
47	Basic Service Charge: Apr'19 - Dec'19	1,274	$30.00	$38,232			538	$16,128	1,812	$54,360	$35.00	$63,420	
48	Delivery Charge: Jan'19 - Mar'19	1,212,715	$0.205570	$249,298			(1,212,715)	-$249,298					
49	Delivery Charge: Apr'19 - Dec'19	2,047,657	$0.225820	$462,402			1,149,131	$259,497	3,196,788	$721,899	$0.329590	$1,053,629	
50	Total Margin			$755,236				$21,023		$776,259		$1,117,049	$340,791
51	Average Cost of Gas			$1,100,666									
52	Non-Gas Revenue												
53	Adjustment Dollars			-$112									
54	Franchise Tax			$45,215									
55	OR Unprotected Excess Deferred Income Tax			-$3,703									
56	CNG OR INTERIM PERIOD EDIT			-$5,422									
57	Public Purpose Fund R/S 31			$113,916									
58	PPC and Adjustments			-$5									
59	Subtract out PPC Fund & Adjustments			-$113,911									
60	Deferrals Revenue			-$2,076				$2,076					
61	Deficiency Billings			$0				$0					
62	Total Non-Gas Revenue			$33,902				$2,076					
63	**Total Rate Schedule 105 Revenue**			**$1,889,804**				**$23,099**					
			check	$0									
64	**Rate Schedule 111 - Large Volume Firm Commercial Service**												
65	COMMERCIAL				*Merged from CNGOR011LV*								
66	Basic Service Charge: Jan'19 - Mar'19	27	$0.00	$0	0		(27)	$0					
67	Basic Service Charge: Apr'19 - Dec'19	87	$125.00	$10,863	3	375	54	$6,763	144	$18,000	$144.00	$20,736	
68	Delivery Charge: Jan'19 - Mar'19	344,921	$0.165920	$57,229	0	0	(344,921)	-$57,229					
69	Delivery Charge: Apr'19 - Dec'19	572,643	$0.158280	$90,638	345,487	54,684	727,618	$115,167	1,645,748	$260,489	$0.169080	$278,263	
70	Total Margin			$158,730		55,059		$64,701		$278,489		$298,999	$20,510
71	Average Cost of Gas			$307,218									
72	Non-Gas Revenue												
73	Adjustment Dollars			$0									
74	Franchise Tax			$9,280									
75	OR Unprotected Excess Deferred Income Tax			-$819									
76	CNG OR INTERIM PERIOD EDIT			-$1,080									
77	Public Purpose Fund R/S 31			$28,711									
78	PPC and Adjustments			$0									
79	Subtract out PPC Fund & Adjustments			-$28,711									
80	Deferrals Revenue			-$844				$844					
81	Deficiency Billings			$0				$0					
82	Total Non-Gas Revenue			$6,538				$844					

Cascade Natural Gas Corporation
Revenue Proof

CNGC/401
Myhrum/2

Line	Rate Description	Billing Determinants (Therms/Bills)	Current Rate	Per Books Revenue	Therms/Bills Merge	Remove/Add Revenue	Billing Determinants (Therms/Bills)	Revenue Adjustment	Billing Determinants (Therms/Bills)	Revenue at Current Rates	Proposed Rates	Revenue at Proposed Rates	Increase
		Current					Future Test Year Adjustments		Pro Forma		Proposed		
	(A)	(B)	(C)	(D) = (B)*(C)	(E)	(F)	(G)	(H) = (C)*(G)	(I) = (B)+(G)	(J) = (C)*(I)	(K)	(L) = (I)*(K)	(M) = (L)-(J)
								$125	*Merged from CNGOR011LV*				
83	COMMERCIAL CNGOR011LV				*Merge with RS 111 Commercial*			$969					
84	Basic Service Charge: Jan'19 - Oct'19		$0.00	$0	-								
85	Basic Service Charge: Nov'19 - Dec'19	3	$125.00	$375	(3)	-$375							
86	Delivery Charge: Jan'19 - Oct'19	-	$0.165920	$0	-	$0							
87	Delivery Charge: Nov'19 - Dec'19	345,487	$0.158280	$54,684	(345,487)	-$54,684							
88	Total Margin			$55,059		-$55,059							
89	Average Cost of Gas			$121,796									
90	Non-Gas Revenue												
91	Adjustment Dollars			$8									
92	Franchise Tax			$0									
93	OR Unprotected Excess Deferred Income Tax			-$797									
94	CNG OR INTERIM PERIOD EDIT			-$871									
95	Public Purpose Fund R/S 31			$11,002									
96	PPC and Adjustments			$0									
97	Subtract out PPC Fund & Adjustments			-$11,002		*Merge with RS 111 Commercial*							
98	Deferrals Revenue			$0		$0		$0					
99	Deficiency Billings			$0		$0		$0					
100	Previous Month CA1501A -			-$181,729		$181,729		$0					
101	Current Month CA1501A +			$181,854		-$181,854		$0					
102	Total Non-Gas Revenue			-$1,535		-$125		$0					
103	Total COMMERCIAL CNGOR011LV Revenue			$ 175,319.18									
				$ (0.01)	Off due to O91 in RR								
104	INDUSTRIAL												
105	Basic Service Charge: Jan'19 - Mar'19	27	$0.00	$0			(27)						
106	Basic Service Charge: Apr'19 - Dec'19	73	$125.00	$9,075			23	$2,925	96	$12,000	$144.00	$13,824	
107	Delivery Charge: Jan'19 - Mar'19	592,817	$0.165920	$98,360			(592,817)	-$98,360					
108	Delivery Charge: Apr'19 - Dec'19	1,140,842	$0.158280	$180,572			228,739	$36,205	1,369,581	$216,777	$0.169080	$231,569	
109	Total Margin			$288,008				-$59,230		$228,777		$245,393	$16,615
110	Average Cost of Gas			$576,647									
111	Non-Gas Revenue												
112	Adjustment Dollars			$0									
113	Franchise Tax			$8,933									
114	OR Unprotected Excess Deferred Income Tax			-$1,360									
115	CNG OR INTERIM PERIOD EDIT			-$1,734									
116	Public Purpose Fund R/S 31			$53,544									
117	PPC and Adjustments			$0									
118	Subtract out PPC Fund & Adjustments			-$53,544									
119	Deferrals Revenue			-$1,022				$1,022					
120	Deficiency Billings			$0				$0					
121	Total Non-Gas Revenue			$4,816				$1,022					
122	**Total Rate Schedule 111 Revenue**			**$1,341,956**				**$7,461**					
			check	$0									
123	**Rate Schedule 170 - Interruptible Service**												
124	Basic Service Charge: Jan'19 - Apr'19	16	$0.00	$0			(16)	$0					
125	Basic Service Charge: May'19 - Dec'19	32	$300.00	$9,600			16	$4,800	48	$14,400	$345.00	$16,560	
126	Delivery Charge: Jan'19 - Apr'19	1,333,593	$0.123090	$164,152			(1,333,593)	-$164,152					
127	Delivery Charge: May'19 - Dec'19	1,311,685	$0.123760	$162,334			605,912	$74,988	1,917,597	$237,322	$0.122630	$235,155	
128	Total Margin			$336,086				-$84,364		$251,722		$251,715	-$7
129	Average Cost of Gas			$873,067									
130	Non-Gas Revenue												
131	Adjustment Dollars			$0									
132	Franchise Tax			$12,427									
133	OR Unprotected Excess Deferred Income Tax			-$1,265									
134	CNG OR INTERIM PERIOD EDIT			-$1,515									
135	Public Purpose Fund R/S 31			$73,591									
136	PPC and Adjustments			$0									
137	Subtract out PPC Fund & Adjustments			-$73,591									
138	Deferrals Revenue			-$1,826				$1,826					
139	Deficiency Billings			$0				$0					
140	Previous Month CA1501A -			-$1,218,801				$1,218,801					
141	Current Month CA1501A +			$1,251,585				-$1,251,585					
142	Total Non-Gas Revenue			$40,605				-$30,957					
143	**Total Rate Schedule 170 Revenue**			**$1,249,758**				**-$115,322**					
			check	$0									

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	Therms/Bills Merge	Remove/Add 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)	(G)	(H) = (C)*(G)	(I) = (B)+(G)	(J) = (C)*(I)	(K)	(L) = (I)*(K)	(M) = (L)-(J)
144	**Rate Schedule 163 - Interruptible Transportation**												
145	Basic Service Charge: Jan'19 - Apr'19	132	$500.00	$66,000			(132)	-$66,000					
146	Basic Service Charge: May'19 - Dec'19	271	$625.00	$169,375			173	$108,125	444	$277,500	$719.00	$319,236	
147	Commodity Charge												
148	First 10,000 Therms: Jan'19 - Mar'19	1,068,431	$0.124020	$132,507			(92,641)	-$11,489	975,790	$125,221	$0.157470	$153,658	
149	Next 10,000 Therms: Jan'19 - Mar'19	927,727	$0.111880	$103,794			(114,074)	-$12,763	813,652	$94,193	$0.142050	$115,579	
150	Next 30,000 Therms: Jan'19 - Mar'19	1,657,110	$0.105120	$174,195			(203,124)	-$21,352	1,453,986	$158,152	$0.133470	$194,064	
151	Next 50,000 Therms: Jan'19 - Mar'19	1,541,742	$0.064560	$99,535			(154,495)	-$9,974	1,387,246	$92,672	$0.081970	$113,713	
152	Next 400,000 Therms: Jan'19 - Mar'19	5,231,775	$0.032750	$171,341			(873,978)	-$28,623	4,357,797	$147,677	$0.041580	$181,197	
153	Next 500,000 Therms: Jan'19 - Mar'19	318,286	$0.017550	$5,586			37,752	$663	356,038	$6,466	$0.022280	$7,933	
154	First 10,000 Therms: Apr'19 - Dec'19	2,417,759	$0.128328	$310,266			682,813	$87,624	3,100,573	$397,890	$0.157470	$488,247	
155	Next 10,000 Therms: Apr'19 - Dec'19	1,897,613	$0.115766	$219,679			535,294	$61,969	2,432,907	$281,648	$0.142050	$345,594	
156	Next 30,000 Therms: Apr'19 - Dec'19	3,405,475	$0.108771	$370,417			943,601	$102,636	4,349,077	$473,053	$0.133470	$580,471	
157	Next 50,000 Therms: Apr'19 - Dec'19	3,670,449	$0.066803	$245,197			848,394	$56,675	4,518,843	$301,872	$0.081970	$370,410	
158	Next 400,000 Therms: Apr'19 - Dec'19	11,655,885	$0.033888	$394,995			1,266,837	$42,931	12,922,722	$437,925	$0.041580	$537,327	
159	Next 500,000 Therms: Apr'19 - Dec'19	1,248,131	$0.018160	$22,666			(259,473)	-$4,712	988,658	$17,954	$0.022280	$22,027	
160	Total Margin			$2,485,553				$305,709		$2,812,224		$3,429,455	$617,231
161	Average Cost of Gas			$0									
162	Non-Gas Revenue												
163	Adjustment Dollars			$6,980									
164	Franchise Tax			$30,700									
165	OR Unprotected Excess Deferred Income Tax			-$10,255									
166	CNG OR INTERIM PERIOD EDIT			-$8,874									
167	Gross Revenue Fee			$72,639									
168	Deferrals Revenue			-$20,607				$20,607					
169	Previous Month CA1501A -			-$2,576,743				$2,576,743					
170	Current Month CA1501A +			$2,602,471				-$2,602,471					
171	Total Non-Gas Revenue			$96,312				-$5,122					
172	**Total Rate Schedule 163 Revenue**			**$2,581,865**				**$300,587**					
			check	$0									
173	**Rate Schedule 902 - Interruptible Transportation**												
174	Dispatch Service Charge	12	$500.00	$6,000			-	$0	12	$6,000	$500.00	$ 6,000	
175	Contract Demand Charge	10,800,000	$0.1005555	$1,085,999			-	$0	10,800,000	$1,085,999	$0.1005555	$ 1,085,999	
176	Delivery Charge: Jan'19 - Sep'19	147,781,586	$0.0016113	$238,120			(147,781,586)	-$238,120	-				
177	Delivery Charge: Oct'19 - Dec'19	63,421,532	$0.0016371	$103,827			102,579,270	$167,933	166,000,802	$271,760	$0.0016371	$ 271,760	
178	Total Margin			$1,433,947				-$70,188		$1,363,759		$1,363,759	$0
179	Non-Gas Revenue												
180	Adjustment Dollars			-$22,139									
181	Franchise Tax			$0									
182	Gross Revenue Fee			$41,904									
183	Previous Month CA1501A -			-$1,453,713				$1,453,713					
184	Current Month CA1501A +			$1,453,860				-$1,453,860					
185	Total Non-Gas Revenue			$19,912				-$147					
186	**Total Rate Schedule 902 Revenue**			**$1,453,860**				**-$70,335**					

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	Therms/Bills Merge	Remove/Add 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)	(G)	(H) = (C)*(G)	(I) = (B)+(G)	(J) = (C)*(I)	(K)	(L) = (I)*(K)	(M) = (L)-(J)
			check	$0									
187	**Rate Schedule 903 - Interruptible Transportation**												
188	Dispatch Service Charge: Jan'19 - Jul'19	7	$500.00	$3,500			(7)	-$3,500					
189	Dispatch Service Charge: Aug'19 - Dec'19	5	$625.00	$3,125			7	$4,375	12	$7,500	$625.00	$7,500	
190	Contract Demand Charge	192,000	$0.0937500	$18,000			-	$0	192,000	$18,000	$0.093750	$18,000	
191	Delivery Charge: Jan'19 - Sep'19	6,596,342	$0.0123475	$81,448			(6,596,342)	-$81,448	-	$0			
192	Delivery Charge: Oct'19 - Dec'19	2,312,558	$0.0125451	$29,011			5,961,781	$74,791	8,274,339	$103,802	$0.012545	$103,802	
193	Total Margin			$135,085				-$5,782		$129,302		$129,302	$0
194	Non-Gas Revenue												
195	Adjustment Dollars			$3,915									
196	Franchise Tax			$0									
197	Gross Revenue Fee			$3,948									
198	Previous Month CA1501A -			-$142,947				$142,947					
199	Current Month CA1501A +			$145,477				-$145,477					
200	Total Non-Gas Revenue			$10,393				-$2,530					
201	**Total Rate Schedule 903 Revenue**			**$145,477**				**-$8,312**					
			check	$0									
202	**Rate Schedule 904 - Interruptible Transportation**												
203	Dispatch Service Charge: Jan'19 - Jul'19	7	$500.00	$3,500			(7)	-$3,500					
204	Dispatch Service Charge: Aug'19 - Dec'19	5	$625.00	$3,125			7	$4,375	12	$7,500	$625.00	$7,500	
205	Contract Demand Charge	499,200	$0.0877404	$43,800			-	$0	499,200	$43,800	$0.087740	$43,800	
206	Delivery Charge: Jan'19 - Sep'19	6,216,263	$0.0082819	$51,482			(6,216,263)	-$51,482	-	$0			
207	Delivery Charge: Oct'19 - Dec'19	2,195,195	$0.0084144	$18,471			7,120,477	$59,915	9,315,672	$78,386	$0.008414	$78,386	
208	Total Margin			$120,379				$9,307		$129,686		$129,686	$0
209	Non-Gas Revenue												
210	Adjustment Dollars			$0									
211	Franchise Tax			$4,956									
212	Gross Revenue Fee			$3,518									
213	Previous Month CA1501A -			-$128,853				$128,853					
214	Current Month CA1501A +			$128,562				-$128,562					
215	Total Non-Gas Revenue			$8,184				$290					
216	**Total Rate Schedule 904 Revenue**			**$128,562**				**$9,597**					
			check	$0									
217	**Rate Schedule 905 - Interruptible Transportation**												
218	Dispatch Service Charge: Jan'19 - Jul'19	7	$500.00	$3,500			(7)	-$3,500		$0			
219	Dispatch Service Charge: Aug'19 - Dec'19	5	$625.00	$3,125			7	$4,375	12	$7,500	$625.00	$7,500	
220	Contract Demand Charge	480,000	$0.0437500	$21,000			-	$0	480,000	$21,000	$0.043750	$21,000	
221	Delivery Charge: Jan'19 - Sep'19	5,617,063	$0.0115915	$65,110			(5,617,063)	-$65,110	-	$0			
222	Delivery Charge: Oct'19 - Dec'19	1,971,135	$0.0117770	$23,214			6,338,907	$74,653	8,310,042	$97,867	$0.011777	$97,867	
223	Total Margin			$115,949				$10,418		$126,367		$126,367	$0
224	Non-Gas Revenue												
225	Adjustment Dollars			$0									
226	Franchise Tax			$0									
227	Gross Revenue Fee			$3,389									
228	Previous Month CA1501A -			-$119,338				$119,338					
229	Current Month CA1501A +			$122,512				-$122,512					
230	Total Non-Gas Revenue			$6,563				-$3,175					
231	**Total Rate Schedule 905 Revenue**			**$122,512**				**$7,243**					
			check	$0									
232	**Total Cascade Margin**			**$37,813,018**				**$507,609**		$36,963,252		$41,471,078	**$4,507,827**
233	**Total Cascade Revenue**			$67,101,002									
234	**Miscellaneous Service Revenues**			$169,984									
235	**Rent From Gas Property**			$12,000									
236	**Interdepartmental Rents**			$42,263									
237	**Other Gas Revenue**			$13,492									
238	**Provision for Rate Refund**			-$268,153									
239	**TOTAL OPERATING REVENUE**			$67,070,587						$67,578,196			
				$0.00									
			check	$0.00									

Average Cost of Gas	$29,533,676
Adjustment	$0
Franchise Tax	$1,453,385
OR Unprotected Excess Deferred Income Tax	-$158,008
CNG OR INTERIM PERIOD EDIT	-$230,520
PPC and Adjustments	-$2,866
Public Purpose Fund	$0
Subtract out PPC Fund & Adjustments	-$3,846,050
Current Month Unbilled +	$39,540,060
Previous Month Unbilled -	-$39,487,981
CAP Adjustment	-$2,927,481
Deferrals	$0
Deficiency	$0
Gross Revenue Fee	$125,398
Previous Month CA1501A -	-$5,822,123
Current Month CA1501A +	$5,886,322
	$61,876,830

Sales	$62,668,726	Sales	$268,828.25
Transport	$4,432,276	Transport	$238,780.95

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

ISAAC D.
MYHRUM
Exhibit No. 402

Calculation of Baseline Monthly Commodity Margin Per Customer

Cascade Natural Gas Coporation
CAP Baseline
UG 390
Twelve Months Ended December 31, 2019

R/S 101	0.41246
R/S 104	0.26731

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-20	7,820,631	67,134	$ 3,225,697.57	$ 48.05
Feb-20	6,434,600	67,265	$ 2,654,015.26	$ 39.46
Mar-20	4,898,945	67,425	$ 2,020,618.80	$ 29.97
Apr-20	3,520,813	67,518	$ 1,452,194.45	$ 21.51
May-20	2,235,964	67,543	$ 922,245.61	$ 13.65
Jun-20	1,414,816	67,541	$ 583,554.80	$ 8.64
Jul-20	1,107,587	67,579	$ 456,835.41	$ 6.76
Aug-20	1,098,689	67,641	$ 453,165.22	$ 6.70
Sep-20	1,617,943	67,634	$ 667,336.67	$ 9.87
Oct-20	3,430,675	68,037	$ 1,415,016.07	$ 20.80
Nov-20	5,959,809	68,384	$ 2,458,182.81	$ 35.95
Dec-20	8,375,576	68,748	$ 3,454,590.01	$ 50.25
Total	47,916,047	812,449	$ 19,763,452.66	**$ 291.60**
Average		67,704		
Commercial Rate Schedule 104				
Jan-20	4,847,434	10,232	$ 1,295,767.62	$ 126.64
Feb-20	4,021,919	10,235	$ 1,075,099.06	$ 105.04
Mar-20	2,903,929	10,247	$ 776,249.24	$ 75.75
Apr-20	2,099,918	10,258	$ 561,329.16	$ 54.72
May-20	1,461,498	10,244	$ 390,672.98	$ 38.14
Jun-20	1,090,891	10,228	$ 291,606.11	$ 28.51
Jul-20	982,016	10,207	$ 262,502.76	$ 25.72
Aug-20	971,511	10,186	$ 259,694.62	$ 25.50
Sep-20	1,279,502	10,176	$ 342,023.57	$ 33.61
Oct-20	2,254,759	10,194	$ 602,719.56	$ 59.12
Nov-20	3,793,158	10,234	$ 1,013,949.05	$ 99.08
Dec-20	5,225,377	10,292	$ 1,396,795.64	$ 135.72
Total	30,931,912	122,733	$ 8,268,409.35	**$ 807.54**
Average		10,228		

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

UG 390

Cascade Natural Gas Corporation

Direct Testimony of Pamela J. Archer

EXHIBIT 500

March 31, 2020

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 West 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 a Senior Regulatory Analyst in the Regulatory Affairs Section. Among my duties, I am responsible for preparing cost of service studies and revenue allocation related issues in general rate cases, regulatory reports, tariff and compliance filings, and other regulatory filings for Cascade that are filed with the Public Utility Commission of Oregon ("Commission") and the Washington Utilities and Transportation Commission ("WUTC"). I also provide regulatory advice and knowledge to others within the Company.

Q. How long have you been employed by Cascade?

A. I have been employed by the Company since September 2010.

Q. Would you please state your educational and professional qualifications?

A. I graduated from The Ohio State University in 1992, receiving a Bachelor of Science degree in Chemical Engineering; and a Master of Business Administration degree from Ashland University in 1996. I have taken post-graduate courses from The Ohio State University in Managerial Accounting, Corporate Finance, and Business Law.

Prior to joining Cascade, I was employed as an Energy Specialist at the Office of the Ohio Consumers' Counsel for 15 years. I have attended several regulatory courses and conferences, including the 34th Annual National Association of Regulatory Utility Commissioners ("NARUC") Regulatory Studies Program held at Michigan State University, as well as other NARUC and National Association of State Utility Consumer Advocates sponsored events.

Q. Have you testified before this Commission before?

A. Yes. I have testified before this Commission in Cascade's three most recent general rate cases in Docket Numbers UG 287, UG 305, and UG 347.

Q. Have you testified before other Commissions before?

A. Yes. I have also testified before the WUTC on behalf of the Company in Docket Numbers UG-152286 and UG-190210 and before the Public Utilities Commission of Ohio on behalf of the Office of the Ohio Consumers' Counsel in Docket Numbers 93-2006-GA-AIR, 94-996-EL-AIR, 94-1918-EL-AIR, 95-656-GA-AIR, 01-1228-GA-AIR, 04-571-GA-AIR, and 05-0059-EL-AIR.

II. SCOPE AND SUMMARY OF TESTIMONY

Q. What is the purpose of your testimony?

A. I present the Company's natural gas long-run incremental cost ("LRIC") study, revenue allocation, and rate design. I also introduce all proposed changes to Cascade's current rate schedules.

Q. Please summarize the Company's approach for the natural gas cost of service study, revenue allocation, and rate design.

A. The Company's natural gas LRIC study reasonably functionalizes, classifies, and allocates capital investments and operating expenses to each rate schedule.

Based on the results from the cost study, the Company has proposed a revenue allocation where Schedules 101, 105, and 163 get a higher than average increase to move them closer to parity, while the remaining schedules which are below parity, get an average or below average increase.

As for natural gas rate design, the Company proposes increasing the monthly service charge to $6, $12, and $35 for Schedules 101, 104, and 105, respectively, to recover more fixed costs through the basic service charge. The Company also proposes increasing the basic service charge to $144 and $719 for its Schedule 111 and Schedule 163, respectively, for the same rationale.

Q. Do you sponsor any exhibits in support of the Company's proposal in this proceeding?

A. Yes, I sponsor the following exhibits in support of my testimony:

Exhibit No. CNGC/501	Summary of LRIC Study
Exhibit No. CNGC/502	Functional Revenue Requirement
Exhibit No. CNGC/503	Incremental Plant Carrying Costs
Exhibit No. CNGC/504	Incremental O&M Costs
Exhibit No. CNGC/505	Summary of Revenue by Rate Class
Exhibit No. CNGC/506	Analysis of Revenue by Detailed Rate Schedule
Exhibit No. CNGC/507	Residential Impact by Month
Exhibit No. CNGC/508	Impact of Recommended Rate Changes

Q. Do you sponsor any other exhibits in this proceeding?

A. Yes. I also introduce all proposed changes to Cascade's current rate schedules. The proposed tariff changes, as well as all legislative tariffs containing the changes in red-lined, strike-out text are included as exhibits CNGC/509 and CNGC/510, respectively.

Exhibit No. CNGC/509 Proposed Tariff Sheets

Exhibit No. CNGC/510 Redlined Tariff Sheets

III. <u>LONG-RUN INCREMENTAL COST STUDY</u>

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I present the Company's LRIC study results for its Oregon operations.

Q. Have you prepared Cascade's cost study filed in this proceeding?

A. Yes. I prepared Cascade's LRIC study as presented in Exhibit CNGC/501 that reflects the summary of the results. The study reasonably functionalizes, classifies, and allocates capital investments and operating expenses to each rate schedule.

Q. What is the purpose of a cost of service study?

A. The cost of service study allows the Company to consider the cost to serve each rate class, including embedded and long-run costs, and apportion the revenue requirement to each customer class accordingly based on the cost of service. The overall objective is to reasonably functionalize, classify, and allocate capital investments and operating expenses to each rate schedule based on cost causation.

Q. Can you describe the methodology used to prepare the cost study?

A. The main components of the Company's LRIC study are incremental plant investments, as well as the incremental operations and maintenance ("O&M") expenses. The incremental cost information related to these components are accumulated on a per customer basis for each of the Company's customer classes and are summarized to represent the long-run incremental cost for customers on Cascade's local distribution system.

Q. Has the Company used this methodology previously?

A. Yes, the Company has used the LRIC methodology in its previous three general rate case proceedings before this Commission, Docket Nos. UG 287, UG 305, and UG 347.

A. Incremental Plant Investment Costs

Q. What are the components that comprise the Company's incremental plant investment?

A. Three components comprise Cascade's incremental plant investment. These components are: 1) the cost to install distribution mains; 2) the cost to provide a service line; and 3) the cost to provide a meter and regulator to serve new customers.

Q. Can you briefly describe the distribution main component of the incremental plant investment?

A. The distribution main cost components can best be described as the Company's investments to: a) connect new customers to the system; b) provide capacity reinforcements to new and existing customers; c) address safety and reliability requirements for all customers; and d) invest in long-term system main replacement.

Q. How did the Company calculate the cost to install distribution mains in the study for the various functions described in the previous response?

A. The Company performed a distribution main analysis to derive the customer-related costs associated with the installation of distribution mains to connect new customers. First, Cascade used plant accounting records to extract the investment in distribution mains by summarizing the new business project work orders in Oregon for an 18-year period from 2002-2019. Then, the Company calculated the customer-associated cost by taking the average cost per foot of Cascade's minimum-sized distribution main, which was two-inches, and escalating this cost to current dollars by using the 2019 Handy Whitman Index of Public Utility Construction Costs. The Company then multiplied the resulting unit cost by the number of feet installed per new customer for the residential, commercial, and industrial customer classes, Schedule Nos. 101, 104, and 105, respectively to calculate the distribution main cost for these customer classes.

For the larger core classes, Schedule Nos. 111 and 170, and the non-core class, Schedule No. 163, as well as the Special Contract Class, Schedule No. 900, the Company identified distribution main segments using Cascade's Geographic Information System ("GIS") data. The Company then compiled the GIS data, the in-service date of the main segment, its size, the type, and length and escalated these amounts to the most recent 2019 dollars to compute the corresponding costs. For the smaller core classes, Schedule Nos. 101 and 104, the Company performed a regression analysis on recent work orders for main extensions to determine the typical feet of mains per customer. Finally, for industrial rate Schedule No. 105, the Company used work orders to determine the typical feet of mains per customer.

Q. How did the Company determine the incremental cost of distribution mains for long-term system replacement investments?

A. The Company estimated the long-term distribution main replacement costs by calculating the current cost of mains in service as of December 2019. The Company then subtracted the current cost of the distribution mains in the previous response as well as new customer main extensions to determine the remaining level of system replacement investment. This remaining amount of investment was then separated into capacity and commodity components using Cascade's Oregon load factor and then allocating to the appropriate classes using design day demand and annual throughput, respectively.

Q. What is a load factor and how is the value interpreted?

A. The load factor is a ratio measure of normalized average usage to the estimated design day peak usage of each rate schedule's contribution to the design day peak load. While load could potentially peak for other reasons, load peaks attributable to Oregon customers are based on space heating requirements and are weather-related.

A low load factor ratio indicates that a rate schedule has high peaking load relative to normalized average usage, while a high load factor indicates less weather sensitivity and more predicable base load usage throughout the year.

Q. How were the incremental costs for the mains calculated in the study?

A. After determining the investment costs for mains, the incremental costs for mains were calculated by applying a carrying charge percentage to the previously determined investment costs. The overall derivation of LRIC for mains is shown in Exhibit CNGC/503, Incremental Plant Carrying Costs.

Q. How did the Company determine the cost of installing new services in the study?

A. The incremental cost of installing new services was determined by using the most recent installation costs from 2009 to 2019 and escalating those costs to current dollars using the 2019 Handy Whitman Index of Public Utility Construction Costs. The investment costs are based on the installed cost for customers' typical size and type for core customers on Schedules 101, 104, and 105. For the larger customer classes on Schedules 111, 170, 163, and the Special Contract Class 900, each customer was specifically identified using the GIS system and then valued at current cost. The LRIC for services is shown in Exhibit CNGC/503.

Q. How did the Company determine the costs of meters and regulators?

A. The investment costs for meters and regulators were based on the installed average cost of metering and regulating equipment for the core classes using current 2019 inventory prices. For the larger customer classes, a similar process was used to what was used for services in that each customer was specifically identified using the GIS system and then a valuation was assigned at cost. The LRIC for meters and regulators is shown in Exhibit CNGC/503 along with the previously mentioned LRIC for services.

Q. Please explain the derivation and application of the carrying charge percentage.

A. The carrying charge includes cost of capital (both debt and equity), taxes, and depreciation, and the Company calculates and assigns a carrying charge percentage to each category of investment. The investment carrying charge percentage is multiplied by each category of capital investment to calculate each rate schedule's annual revenue requirement. The revenue requirement calculated for each rate schedule for all incremental capital investment categories is an important factor for allocating the revenue requirement to each rate schedule based on cost causation.

B. Incremental Operating & Maintenance Expenses

Q. Please identify the gas supply related O&M expenses and describe how these costs were treated in the study.

A. The category of gas supply O&M expenses includes the salaries and benefits of personnel in the following Responsibility Centers ("RC"): Gas Supply Resource Planning (RC 4761100), Gas Supply (RC 4761200), Gas Control (RC 4763200), and an overall management expense allocated from the Director of Gas Supply at Montana Dakota Utilities (RC 4766000) who provides departmental oversight for Cascade. These labor expenses were distributed among the categories of Gas Supply Resource Planning, Gas Supply, and Gas Control based on the time allocations reported by the personnel in those respective departments.

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

The Gas Supply Department includes gas supply procurement for core customers, balancing of core system supplies that includes day-to-day storage activities, gas supply reporting such as commodity and closing price reporting, processing supplier invoicing, as well as updating and maintaining North American Energy Standards Board contracts. Additionally, the Gas Supply Department includes activities related to non-core customers, such as imbalance “packing” or “drafting” that affects the overall system balance position. The expenses associated with the Gas Supply Department were first segregated between core and non-core classes according to the assigned labor hours and were then allocated among the core and non-core classes using sales and transportation volumes.

The Gas Control Department consists of six gas controllers who provide 24-hour daily monitoring and management of the flow of gas on Cascade’s pipeline system in Oregon. This monitoring is accomplished by the electronic monitoring of various points on the system through supervisory control and data acquisition (“SCADA”) and Metretek measuring equipment. The SCADA sites are located at town border stations throughout Cascade’s system and at one special contract customer location, while Metretek monitoring equipment is located at non-core customer locations for Schedules 170, 163, and 900. The expenses charged to this function were first segregated between core and non-core classes according to a recent study of alarms triggered by information provided by the SCADA and Metretek sites, then allocated between the core and non-core classes using sales or transportation volumes. The results of the Gas Supply related O&M expenses are shown in Exhibit CNGC/504.

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

A. The category of incremental customer related O&M expenses includes several different Federal Energy Regulatory Commission ("FERC") accounts, including: Meter Reading (FERC Account 902); Customer Records and Collections that includes monthly billing, postage and printing (FERC Account 903); and Uncollectible Accounts (FERC Account 904). These FERC accounts involve the following specific RCs: 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 (RC 4767500, RC 4767800); and all the Oregon Districts (Bend RC 47041,RC 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 the labor costs of the field personnel involved in meter reading activities related to the respective customer classes and then allocated on a customer basis. Customer records and collections expenses were first directly assigned to those classes that receive manual billing, Schedules 163, 170, and 900, and the remaining costs were allocated to all classes on a customer basis. All uncollectible accounts expenses were assigned to the classes based on account write-offs. All the results of the previously discussed allocations related to customer service O&M can be seen in Exhibit CNGC/504.

C. LRIC Study Results

Q. Please explain how the Company's LRIC study is used to determine parity ratios for each customer class.

A. The study compares the ratio of test year margin revenue at current rates against the margin revenue amount that includes the proposed incremental revenue requirement. This ratio is used to derive the relative margin-to-cost ratio at present rates, which indicates each rate schedule's position relative to cost parity (i.e., the point that the schedule is neither over- nor under-paying its cost to serve). The parity ratio figures presented do not contain any commodity-related revenues, such as commodity cost related to unaccounted for gas.

A parity ratio below the value of one indicates that customers on a given rate schedule are underpaying the cost to serve them, while a value over one indicates that customers on a given rate schedule are paying more than the cost to serve them.

Q. What were the findings from the Company's LRIC study?

A. As shown in Exhibit CNGC/501, the LRIC study indicates that the interruptible customer class is paying more than their determined cost to serve, while the remaining customer classes are paying less than their determined cost to serve. The parity ratios for each customer class are presented in Exhibit CNGC/501 on lines 61 and 62.

Q. How do these results compare with Cascade's last filed study?

A. The results from the LRIC study show that some customer classes have deteriorated and moved further away from parity, while others have slightly improved when compared to the Company's last filed study, as part of Docket UG 347. The interruptible and special contract customers remain above parity, just as they were in the last case.

Q. Can you be more specific on how the parity results compare to the last study?

A. The following shows how the parity ratios have changed since the prior LRIC study was performed in the last case:

- Schedule 101 – parity ratio of 0.82 (current) vs. 0.87 (prior)
- Schedule 104 – parity ratio of 0.98 (current) vs. 1.01 (prior)
- Schedule 105 – parity ratio of 0.72 (current) vs. 0.52 (prior)
- Schedule 111 – parity ratio of 0.98 (current) vs. 1.08 (prior)
- Schedule 163 - parity ratio of 0.85 (current) vs. 0.83 (prior)
- Schedule 170 – parity ratio of 1.62 (current) vs. 1.72 (prior)

IV. REVENUE ALLOCATION

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I present the Company's revenue allocation results for its Oregon operations.

Q. Does the Company propose any changes to its rate structure or to its current rate schedule offerings?

A. No. Cascade is not proposing any additions or removals of rate schedules in Oregon, nor is it changing any block rate structures or intra-schedule optionality that it currently offers for its Oregon operations.

Q. What is Cascade's proposed revenue allocation for gas service?

A. As mentioned above, the gas cost of service study results show that the majority of customer classes are not covering their cost to serve, while the interruptible customer class is paying more than the cost to serve. Because the Company recommends increasing overall gas margin revenue by 12.2 percent, and in order to move gas rate schedules closer to parity, the Company recommends the following increases to the margin revenue:

- Schedule 101, Residential, gets an average increase of 16.0 percent.
- Schedules 104, General Service, gets an increase of 2.4 percent.
- Schedules 105, General Service, gets an increase of 40.2 percent.
- Schedules 111, Large General Service, gets an increase of 1.8 percent.
- Schedules 170, Interruptible, gets no increase.
- Schedule 163, Transportation, gets an increase of 17.1 percent.

Q. Please explain your analysis for Schedules 101, 105, and 163 getting a higher than average increase, while the remaining rate schedules get a below average increase.

A. The Company determined that each customer class that was below parity should receive an increase, and those at or below 15 percent of parity should receive above average increases to move them closer to cost parity. To reach parity, the Company's analysis shows that customers on Schedules 101, 105, and 163 are at 0.82, 0.72, and 0.85 of parity, respectively, which would require above average increases between 17.1 to 40.2 percent to get these schedules to parity. The customers on Schedules 104 and 111 are both at 0.98 of parity, which would require a below average increase between 1.8 and 2.4 percent, respectively, to get these schedules to parity. For this reason, the Company calculated changes to the revenue allocation that will address parity imbalances, while placing all customer classes within 5 percent of parity, except for Schedule 170. The Residential customer class is still below parity, at 0.95 of parity.

Q. How are the parity ratios affected by the Company's proposal?

A. The Company's long-term goal is to set rates within five percent of the theoretical parity for each class and the recommended rate spread is designed to do just that without producing unacceptably large customer impacts based on the overall increase. Exhibit No. CNGC/501.

Q. How does this proposal reflect consideration of fairness, equity, economic conditions, and rate stability?

A. The Company's recommendation emphasizes the customer class relationship to parity and customer bill impacts. The parity percentages discussed earlier indicate that some classes currently pay less than it costs to serve them, and other classes pay more than it costs to serve them. Because this relationship between costs and revenues varies by customer class, the Company's earned return also varies by customer class. By adjusting revenue allocation, classes can be brought closer to paying the costs incurred to serve the class and class level rates of return can be brought closer to the system average rate of return.

The Company recognizes the current economic conditions for our service area, and that a complete shift to the cost of service may cause rate instability. Therefore, the Company is applying the concept of gradualism in small and discrete increments to reduce these imbalances.

V. RATE DESIGN

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I explain the Company's proposed rate design results for its Oregon operations.

Q. Please explain generally the concept of natural gas rate design.

A. Natural gas rate design takes the total allocated revenue for each rate schedule and determines the specific charges within the schedule, such as the basic service charge per month, the demand charge per therms, and the exact cents per therms.

Q. What costs are covered by the gas monthly basic service charge?

A. The gas monthly service charge includes the cost of meters, service drops, meter reading, meter maintenance, and billing. With the delivery charge on a per therm basis, it recovers all remaining costs not covered by the monthly basic service charge.

Q. Is the Company proposing any changes to the monthly basic service charge?

A. Yes. The Company proposes to increase the monthly basic service charge for all rate schedules, except Rate Schedule 170, to reflect the costs that are fixed and that vary with the number of customers, since these costs vary by the number of customers rather than usage; otherwise, all other basic service charges remain unchanged.

Q. How much are the new monthly basic service charges increasing for each rate schedule?

A. The monthly basic service charges are changing as follows:

- Rate Schedule 101: $5.00 to $6.00 per month
- Rate Schedule 104: $10.00 to $12.00 per month
- Rate Schedule 105: $30.00 to $35.00 per month
- Rate Schedule 111: $125.00 to $144.00 per month
- Rate Schedule 163: $625.00 to $719.00 per month

VI. CUSTOMER BILL IMPACTS

Q. What is the purpose of this section of your testimony?

A. In this section of my testimony, I explain the exhibits that illustrate the Company's customer bill impacts for its Oregon operations.

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

A. The monthly and annual bill impacts for a typical residential customer using 699 therms per year are shown in Exhibit CNGC/507. The average monthly increase for a residential customer under the Company's proposed rate design is $4.25 or 8.46% including gas costs.

The average monthly residential bill impacts are depicted on Exhibit CNGC/507, page 1, and bill impacts over varying monthly levels of usage are presented on Exhibit CNGC/508, page 1.

Q. Has the Company prepared bill comparisons for Cascade's other rate classes?

A. Yes. Exhibit CNGC/508, pages 2 through 6, presents bill comparisons for Cascade's non-residential service schedules at varying monthly levels of gas usage.

Q. Does this conclude your testimony?

A. Yes.

CNGC/501
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 501

Summary of LRIC

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Sch 1, Summary

Line No.	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	111,671	59,525	35,631	3,210	1,799	11,507	-	-	-
3	Customer Count	78,148	67,704	10,228	151	20	37	1	4	3
4	Throughput	31,653,582	4,791,605	3,093,191	319,679	301,533	3,765,729	16,600,080	191,760	2,590,005
5	**O&M Costs**									
6	*Gas Supply Related*									
7	Gas Planning	$ 106,046	$ 48,560	$ 29,572	$ 2,756	$ 1,819	$ 6,141	$ 14,505	$ 430	$ 2,263
8	Gas Supply	$ 51,310	$ 25,105	$ 16,206	$ 1,675	$ 1,580	$ 1,538	$ 3,634	$ 1,005	$ 567
9	Gas Control	$ 94,768	$ 35,850	$ 23,143	$ 2,392	$ 2,256	$ 13,491	$ 11,520	$ 1,435	$ 4,682
10	*Customer Related*									
11	Meter Reading	$ 252,256	$ 212,744	$ 32,138	$ 474	$ 2,123	$ 3,927	$ 106	$ 425	$ 318
12	Customer Account Records And Collection	$ 1,326,179	$ 1,144,926	$ 172,959	$ 2,554	$ 338	$ 4,442	$ 120	$ 480	$ 360
13	Billing Postage & Printing	$ 298,103	$ 258,264	$ 39,015	$ 576	$ 76	$ 141	$ 4	$ 15	$ 11
14	Uncollectible	$ 301,876	$ 268,155	$ 33,721	$ -	$ -	$ -	$ -	$ -	$ -
15	Subtotal: O&M Costs	$ 2,430,539	$ 1,993,605	$ 346,754	$ 10,427	$ 8,192	$ 29,681	$ 29,889	$ 3,789	$ 8,202
16	**Customer Investment Carrying Costs**									
17	Meter	$ 7,021,646	$ 4,067,595	$ 2,242,698	$ 147,193	$ 90,999	$ 380,135	$ 33,405	$ 33,887	$ 25,734
18	Service	$ 15,648,124	$ 13,246,145	$ 2,188,247	$ 83,669	$ 20,451	$ 92,368	$ 158	$ 11,217	$ 5,869
19	Mains	$ 12,968,302	$ 8,185,284	$ 1,567,967	$ 1,004,059	$ 285,156	$ 1,054,633	$ 652,195	$ 144,619	$ 74,390
20	Subtotal: Customer Investment Carrying Costs	$ 35,638,072	$ 25,499,023	$ 5,998,912	$ 1,234,921	$ 396,606	$ 1,527,136	$ 685,758	$ 189,723	$ 105,993
21	**System Core Main Carrying Costs**									
22	Capacity	$ 30,643,948	$ 16,334,336	$ 9,777,639	$ 880,754	$ 493,558	$ 3,157,662	$ -	$ -	$ -
23	Commodity	$ 8,313,021	$ 3,195,950	$ 2,063,126	$ 213,222	$ 201,119	$ 2,511,702	$ -	$ 127,902	$ -
24	Subtotal: System Core Main Carrying Costs	$ 38,956,970	$ 19,530,286	$ 11,840,765	$ 1,093,976	$ 694,677	$ 5,669,364	$ -	$ 127,902	$ -
25	**LRIC - Distribution**	$ 77,025,580	$ 47,022,914	$ 18,186,431	$ 2,339,323	$ 1,099,475	$ 7,226,181	$ 715,648	$ 321,414	$ 114,195
26	**Functional Cost Assignment By LRIC**									
27	Scheduling & Planning	$ 252,125	$ 109,516	$ 68,921	$ 6,823	$ 5,655	$ 21,170	$ 29,659	$ 2,869	$ 7,512
28	Meter Reading, Billing, Etc.	$ 2,178,414	$ 1,884,089	$ 277,833	$ 3,604	$ 2,537	$ 8,511	$ 230	$ 920	$ 690
29	Meters & Services	$ 22,669,770	$ 17,313,739	$ 4,430,945	$ 230,862	$ 111,450	$ 472,503	$ 33,563	$ 45,104	$ 31,603
30	Mains Extensions	$ 12,968,302	$ 8,185,284	$ 1,567,967	$ 1,004,059	$ 285,156	$ 1,054,633	$ 652,195	$ 144,619	$ 74,390
31	System Core Mains	$ 38,956,970	$ 19,530,286	$ 11,840,765	$ 1,093,976	$ 694,677	$ 5,669,364	$ -	$ 127,902	$ -
32	**Total**	$ 77,025,580	$ 47,022,914	$ 18,186,431	$ 2,339,323	$ 1,099,475	$ 7,226,181	$ 715,648	$ 321,414	$ 114,195

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Sch 1, Summary

Line No.	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
33	**Non-Gas Revenue At Current Rates**	$ 36,963,252	$ 21,789,745	$ 9,076,921	$ 776,259	$ 507,266	$ 2,812,224	$ 1,363,759	$ 251,722	$ 385,356
34	**Non-Gas Revenue Requirement**									
35	Scheduling And Planning	$ 478,879	$ 208,011	$ 130,907	$ 12,959	$ 10,740	$ 40,210	$ 56,334	$ 5,450	$ 14,268
36	Meter Reading & Billing	$ 3,950,564	$ 3,416,805	$ 503,851	$ 6,536	$ 4,601	$ 15,434	$ 417	$ 1,669	$ 1,251
37	Meters & Services	$ 14,144,854	$ 10,802,946	$ 2,764,698	$ 144,047	$ 69,539	$ 294,819	$ 20,942	$ 28,143	$ 19,719
38	Mains	$ 22,930,285	$ 12,172,521	$ 5,889,039	$ 921,445	$ 430,337	$ 2,953,141	$ 286,440	$ 119,689	$ 157,672
39	**Total LRIC Based Non-Gas Rev Req**	$ 41,504,582	$ 26,600,283	$ 9,288,495	$ 1,084,986	$ 515,218	$ 3,303,605	$ 364,133	$ 154,951	$ 192,910
40	**Revenue To Cost Ratio**	0.89	0.82	0.98	0.72	0.98	0.85	3.75	1.62	2.00
41	**Incremental Non-Gas Revenue Requirement**	$ 4,507,842								
42	**Step 1**									
43	Increase Relative To System Average			0.20	3.30	0.15	1.40	-	-	-
44	Percent Increase	12.20%		2.44%	40.25%	1.83%	17.07%	0.00%	0.00%	0.00%
45	Increase Step 1	$ 1,023,229		$ 221,395	$ 312,406	$ 9,280	$ 480,149	$ -	$ -	$ -
46	**Step 2**									
47	Remainder Allocated On Current Revenue	$ 21,789,745	$ 21,789,745	$ -	$ -	$ -	$ -	$ -	$ -	$ -
48	Increase Step 2	$ 3,484,613	$ 3,484,613	$ -	$ -	$ -	$ -	$ -	$ -	$ -
49	**Total Increase**	$ 41,504,581								
50	Total Non-Gas Revenue Increase	$ 4,507,842	$ 3,484,613	$ 221,395	$ 312,406	$ 9,280	$ 480,149	$ -	$ -	$ -
51	Non-Gas Revenue After Revenue Increase	$ 41,471,094	$ 25,274,358	$ 9,298,316	$ 1,088,664	$ 516,546	$ 3,292,373	$ 1,363,759	$ 251,722	$ 385,356
52	Percent Increase	12.2%	16.0%	2.4%	40.2%	1.8%	17.1%	0.0%	0.0%	0.0%
53	Revenue To Cost Ratio	1.00	0.95	1.00	1.00	1.00	1.00	3.75	1.62	2.00
54	Final Increase Relative To System Average		1.31	0.20	3.30	0.15	1.40	-	-	-
55	**LRIC Supported Customer Cost Per Month**									
56	Cust O&M Plus Meter & Service Carrying Charge		$ 23.63	$ 38.37	$ 129.40	$ 474.95	$ 1,083.36	$ 2,816.11	$ 958.84	$ 897.03
57	Cust O&M		$ 2.32	$ 2.26	$ 1.99	$ 10.57	$ 19.17	$ 19.17	$ 19.17	$ 19.17

CNGC/502
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 502

Functional Revenue Requirement

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Sch 2, Functionalization

No.	FERC	Description	2019 Results	Adjustments	Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains
1		**Plant In Service**								
2		Intangible Plant	$ 12,844,279	$ 626,539	$ 13,470,818	Plant	$ -	$ -	$ 5,491,045	$ 7,979,772
3		Production Plant	-	-	-	DA				-
4		Storage Plant	-	-	-	DA				-
5		Transmission Plant	6,260,460	-	6,260,460	DA				6,260,460
6		Distribution Plant			-	DA				-
7	374	Land And Land Rights	400,444	-	400,444	DA				400,444
8	375	Structures And Improvements	468,476	-	468,476	DA				468,476
9	376	Mains	112,008,130	12,914,475	124,922,605	DA				124,922,605
10	377	Compressor Station	-	-	-	DA				-
11	378	M & R Station Equipment	11,123,788	920,708	12,044,495	DA				12,044,495
12	380	Services	60,772,058	5,139,717	65,911,775	DA			65,911,775	
13	381	Meters	16,705,500	1,063,383	17,768,882	DA			17,768,882	
14	382	Meter Install	9,717,462	-	9,717,462	DA			9,717,462	
15	383	House Regulator & Install.	2,960,580	327,792	3,288,371	DA			3,288,371	
16	385	Industrial M & R Station Equipment	2,441,944	27,321	2,469,264	DA			2,469,264	
17		General Plant	19,229,931	1,099,288	20,329,219	Plant	-	-	8,286,703	12,042,516
18		Subtotal Plant In Service	$ 254,933,050	$ 22,119,221	$ 277,052,271		$ -	$ -	$ 112,933,503	$ 164,118,767
19										
20		**Accumulated Depreciation**								
21		Intangible Plant	$ (5,269,151)	$ (981,644)	$ (6,250,795)	Plant	$ -	$ -	$ (2,547,982)	$ (3,702,813)
22		Production Plant	-	-	-	DA				-
23		Storage Plant	-	-	-	DA				-
24		Transmission Plant	(3,732,975)	(94,716)	(3,827,690)	DA				(3,827,690)
25		Distribution Plant	(93,182,423)	(7,175,277)	(100,357,699)	DistPlant	-	-	(41,988,982)	(58,368,717)
26		General Plant	(7,243,801)	(1,185,726)	(8,429,527)	Plant	-	-	(3,436,088)	(4,993,439)
27		Subtotal Accumulated Depreciation	$ (109,428,349)	$ (9,437,362)	$ (118,865,711)		$ -	$ -	$ (47,973,052)	$ (70,892,659)
28										
29		**Other Ratebase Items**								
30		Contributions In Aid Of Construction	$ -	$ -	$ -				-	
31		Customer Adv. For Construction	(440,037)	-	(440,037)	DA			(440,037)	
32		Deferred Accumulated Income Taxes	(27,470,311)	(20,545)	(27,490,856)	Plant	-	-	(11,205,967)	(16,284,889)
33		Deferred Debits	-	-	-	DA			-	
34		Working Capital Allowance	2,358,018	-	2,358,018	Plant	-	-	961,188	1,396,830
35		Subtotal Other Ratebase	$ (25,552,329)	$ (20,545)	$ (25,572,874)		$ -	$ -	$ (10,684,816)	$ (14,888,058)
36										
37		**Total Ratebase**	$ 119,952,372	$ 12,661,313	$ 132,613,685		$ -	$ -	$ 54,275,635	$ 78,338,050
38		**Rate Of Return**			7.08%					
39		**Return On Ratebase**			$ 9,390,681		$ -	$ -	$ 3,843,383	$ 5,547,298

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Sch 2, Functionalization

No.	FERC	Description	2019 Results	Adjustments	Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains
40										
41		**Operating Expenses**								
42		Production	$ 110,977	1,998	$ 112,974	DA	$ 112,974			
43		Distribution								
44	870	Operation Supervision & Engineering	857,539	-	857,539	OpEx	37,692	-	175,700	644,147
45	871	Distribution Load Dispatching	93,056	-	93,056	OpEx	93,056			
46	872	Compressor Station	-	-	-	OpEx				-
47	874	Mains And Services Expenses	1,392,379	-	1,392,379	OpEx				1,392,379
48	875	Meas. & Reg. Station Expenses	167,374	-	167,374	OpEx				167,374
49	876	Meas. & Reg. Station Expenses - Ind	30,552	-	30,552	OpEx				30,552
50	878	Meter & House Regulator Expenses	212,192	-	212,192	OpEx			212,192	
51	879	Customer Installations Expenses	221,585	-	221,585	OpEx			221,585	
52	880	Other Expenses	2,127,507	-	2,127,507	OpEx	93,511	-	435,902	1,598,094
53	881	Rents	25,710	-	25,710	Plant	-	-	10,480	15,230
54	885	Maint. Supervision & Engineering	241,936	-	241,936	MaintExp	-	-	148,776	93,160
55	886	Maint. Of Structures & Improvements	-	-	-	MaintExp				-
56	887	Maint. Of Mains	259,335	-	259,335	MaintExp				259,335
57	888	Maint. Of Compressor Station Equip.	21	-	21	MaintExp				21
58	889	Maint. Of Meas. & Reg. Station Expenses-General	64,133	-	64,133	MaintExp				64,133
59	890	Maint. Of Meas. & Reg. Station Expenses-Indust.	18,132	-	18,132	MaintExp				18,132
60	892	Maint. Of Services	293,453	-	293,453	MaintExp			293,453	
61	893	Maint. Of Meters & House Regulators	252,112	-	252,112	MaintExp			252,112	
62	894	Maint. Of Other Equipment	394,676	-	394,676	MaintExp	-	-	242,702	151,974
63	N/A	Distribution Adjustments	-	59,116	59,116	DistExp	1,993	-	17,712	39,411
64		Customer Accounts	1,907,206	49,867	1,957,073	DA		1,957,073		
65		Customer Service	307,924	-	307,924	DA		307,924		
66		Sales	2,074	(7,718)	(5,644)	DA		(5,644)		
67		Administrative And General	6,254,289	(245,178)	6,009,112	O&M	139,652	1,691,212	1,352,401	2,825,847
68		Depreciation & Amortization	7,772,990	1,664,373	9,437,362	Plant	-	-	3,846,907	5,590,455
69		Regulatory Debits	-	-	-	Plant	-	-	-	-
70		Taxes Other Than Income	5,734,175	389,820	6,123,994	Plant	-	-	2,496,295	3,627,699
71		State & Federal Income Taxes	191,406	1,268,892	1,460,298	Plant	-	-	595,254	865,044
72		**Total Operating Expense**	$ 28,932,731	$ 3,181,169	$ 32,113,900		$ 478,879	$ 3,950,564	$ 10,301,471	$ 17,382,987
73										
74		**Functionalized Revenue Requirement**	$ 28,932,731	$ 3,181,169	$ 41,504,582		$ 478,879	$ 3,950,564	$ 14,144,854	$ 22,930,285

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 503

Incremental Plant Carrying Costs

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Sch 3, Plant Carrying Costs

Line No.	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	111,671	59,525	35,631	3,210	1,799	11,507	-	-	-	IDM-WP1
3	Customer Count	#	78,148	67,704	10,228	151	20	37	1	4	3	IDM-WP1
4	Throughput	Dth	31,653,582	4,791,605	3,093,191	319,679	301,533	3,765,729	16,600,080	191,760	2,590,005	IDM-WP1
5												
6	**Service Installation**											
7	Typical Size	in.		0.5	1	2						
8	Material			Plastic	Plastic	Plastic						
9	Average Cost	$		$ 1,223	$ 1,338	$ 3,464						PJA-WP1
10	Total Investment	$	$ 97,824,038	$ 82,808,097	$ 13,679,800	$ 523,055	$ 127,848	$ 577,440	$ 988	$ 70,123	$ 36,687	PJA-WP5
11	Economic Carryin Charge Rate	%		16.00%	16.00%	16.00%	16.00%	16.00%	16.00%	16.00%	16.00%	
12	Annual Carrying Charge Per Customer	$		$ 195.65	$ 213.95	$ 554.10						
13	Class Annual Carrying Charge	$	$ 15,648,124	$ 13,246,145	$ 2,188,247	$ 83,669	$ 20,451	$ 92,368	$ 158	$ 11,217	$ 5,869	
14												
15	**Meters & Regulators**											
16	Average Cost	$		$ 373	$ 1,361	$ 6,050						PJA-WP2
17	Total Investment	$	$ 43,576,766	$ 25,243,741	$ 13,918,320	$ 913,488	$ 564,747	$ 2,359,139	$ 207,315	$ 210,307	$ 159,709	PJA-WP5
18	Economic Carryin Charge Rate	%		16.11%	16.11%	16.11%	16.11%	16.11%	16.11%	16.11%	16.11%	
19	Annual Carrying Charge Per Customer	$		$ 60.08	$ 219.28	$ 974.79						
20	Class Annual Carrying Charge	$	$ 7,021,646	$ 4,067,595	$ 2,242,698	$ 147,193	$ 90,999	$ 380,135	$ 33,405	$ 33,887	$ 25,734	
21												
22	**Mains Investment**											
23	*Customer Mains Investment*											
24	Typical Size	in.		2	2	2						
25	Material			Plastic	Plastic	Steel						
26	Avg. Mains Extension Per Cust	ft		86.27	109.39	899.14						PJA-WP 3C & 3D
27	Average Cost Per Ft	$/ft		$ 9.22	$ 9.22	$ 48.66						PJA-WP 3B
28	Customer Mains Investment Per Customer	$		$ 795	$ 1,009	$ 43,751						
29	Customer Mains Investment By Class	$	$ 85,328,104	$ 53,857,072	$ 10,316,819	$ 6,606,451	$ 1,876,251	$ 6,939,213	$ 4,291,277	$ 951,555	$ 489,466	PJA-WP5
30												
31	*Long-Run System Replacement Investment*											
32	Mains System Replacement Cost	$	$ 341,654,988									PJA-WP 3A
33	Less: Customer Mains Investment	$	$ (85,328,104)									
34	Long-Run System Replacement Investment	$	$ 256,326,885									
35												
36	*Capacity*	%	79%									
37	Investment Per Peak Day Capacity	$/Dth-Day	$ 1,806									
38	Investment By Class	$	$ 201,629,332	$ 107,475,747	$ 64,334,359	$ 5,795,133	$ 3,247,485	$ 20,776,608	$ -	$ -	$ -	
39	Investment Per Customer	$		$ 1,587	$ 6,290	$ 38,378	$ 162,374	$ 561,530	$ -	$ -	$ -	
40												
41	*Commodity*	%	21%									
42	System Replacement Investment Per Dth	$/Dth	$ 4.39									
43	Investment By Class	$	$ 54,697,552	$ 21,028,534	$ 13,574,842	$ 1,402,949	$ 1,323,313	$ 16,526,355		$ 841,560		
44	Investment Per Customer	$		$ 311	$ 1,327	$ 9,291	$ 66,166	$ 446,658	$ -	$ 210,390	$ -	
45												
46	Total Mains Investment By Class	$	$ 341,654,988	$ 182,361,353	$ 88,226,019	$ 13,804,533	$ 6,447,050	$ 44,242,175	$ 4,291,277	$ 1,793,116	$ 489,466	
47	Economic Carryin Charge Rate			15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	15.20%	
48	Class Annual Carrying Charge	$	$ 51,925,271	$ 27,715,570	$ 13,408,731	$ 2,098,035	$ 979,833	$ 6,723,996	$ 652,195	$ 272,521	$ 74,390	
49												
50	**Total Carrying Costs**	**$**	**$ 74,595,042**	**$ 45,029,310**	**$ 17,839,677**	**$ 2,328,897**	**$ 1,091,283**	**$ 7,196,500**	**$ 685,758**	**$ 317,625**	**$ 105,993**	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 504

Incremental O&M Costs

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Sch 4, O&M Costs

Line No.	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	111,671	59,525	35,631	3,210	1,799	11,507	-	-	-	
3	Customer Count	78,148	67,704	10,228	151	20	37	1	4	3	
4	Throughput	31,653,582	4,791,605	3,093,191	319,679	301,533	3,765,729	16,600,080	191,760	2,590,005	
5	Sales	8,697,767	4,791,605	3,093,191	319,679	301,533			191,760		
6											
7	Peak & Average	100%	34.2%	20.8%	1.9%	1.3%	11.1%	26.2%	0.3%	4.1%	
8											
9	Customer Count (Small Customers)	78,083	67,704	10,228	151						
10	Customer Count (Large Customers)	65				20	37	1	4	3	
11											
12	Volumes (Core)		4,791,605	3,093,191	319,679	301,533			191,760		
13	Volumes (Non-Core)						3,765,729	16,600,080		2,590,005	
14											
15	**Gas Planning**										
16	Core	$ 83,137	$ 48,560	$ 29,572	$ 2,756	$ 1,819			$ 430		PJA-4A
17	Non-Core	$ 22,909					$ 6,141	$ 14,505		$ 2,263	PJA-4A
18	Total Core + Non-Core	$ 106,046	$ 48,560	$ 29,572	$ 2,756	$ 1,819	$ 6,141	$ 14,505	$ 430	$ 2,263	
19	Cost Per Customer		$ 0.72	$ 2.89	$ 18.25	$ 90.93	$ 165.96	$ 14,505.47	$ 107.46	$ 754.40	
20											
21	**Gas Supply**										
22	Core	$ 45,571	$ 25,105	$ 16,206	$ 1,675	$ 1,580			$ 1,005		PJA-4A
23	Non-Core	$ 5,739					$ 1,538	$ 3,634		$ 567	PJA-4A
24	Total Core + Non-Core	$ 51,310	$ 25,105	$ 16,206	$ 1,675	$ 1,580	$ 1,538	$ 3,634	$ 1,005	$ 567	
25	Cost Per Cust		$ 0.37	$ 1.58	$ 11.09	$ 78.99	$ 41.58	$ 3,633.88	$ 251.18	$ 188.99	
26											
27	**Gas Control**										
28	Core	$ 65,075	$ 35,850	$ 23,143	$ 2,392	$ 2,256			$ 1,435		PJA-4A
29	Non-Core	$ 29,693					$ 13,491	$ 11,520		$ 4,682	PJA-4A
30	Total Core + Non-Core	$ 94,768	$ 35,850	$ 23,143	$ 2,392	$ 2,256	$ 13,491	$ 11,520	$ 1,435	$ 4,682	
31	Cost Per Cust		$ 0.53	$ 2.26	$ 15.84	$ 112.80	$ 364.63	$ 11,519.90	$ 358.68	$ 1,560.63	
32											
33	**Total Gas Supply O&M**	**$ 252,125**	**$ 109,516**	**$ 68,921**	**$ 6,823**	**$ 5,655**	**$ 21,170**	**$ 29,659**	**$ 2,869**	**$ 7,512**	

Cascade Natural Gas Corp.
Oregon Jurisdiction
Long Run Incremental Cost (LRIC) Study
Sch 4, O&M Costs

Line No.	Description	Total	101 Residential Service	104 Commercial Service	105 Industrial Service	111 Large Volume Service	163 General Transportation	902-2 Special Contract	170 Interruptible	9xx Special Contracts	Source
			core	core	core	core	non-core	non-core	core	non-core	
34											
35	**Meter Reading**										
36	Meter Reading Expense (Res, Small Comm.)	$ 245,357	$ 212,744	$ 32,138	$ 474	$ -	$ -	$ -	$ -	$ -	PJA-4B
37	Meter Reading Expense (Industrial)	$ 6,899	$ -	$ -	$ -	$ 2,123	$ 3,927	$ 106	$ 425	$ 318	PJA-4B
38	Meter Reading Expense	$ 252,256	$ 212,744	$ 32,138	$ 474	$ 2,123	$ 3,927	$ 106	$ 425	$ 318	
39	Cost Per Customer		$ 3.14	$ 3.14	$ 3.14	$ 106.14	$ 106.14	$ 106.14	$ 106.14	$ 106.14	
40											
41	**Customer Acoount Records And Collection**										
42	Expense	$ 1,320,776	$ 1,144,926	$ 172,959	$ 2,554	$ 338					PJA-4C
43	Expense - Manual Billing	$ 5,403					$ 4,442	$ 120	$ 480	$ 360	PJA-4C
44	Cost Per Customer		$ 16.91	$ 16.91	$ 16.91	$ 16.91	$ 120.06	$ 120.06	$ 120.06	$ 120.06	
45											
46	**Billing Postage & Printing**										
47	Expense	$ 298,103	$ 258,264	$ 39,015	$ 576	$ 76	$ 141	$ 4	$ 15	$ 11	PJA-4D
48	Cost Per Customer		$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.81	$ 3.81	
49											
50	**Uncollectible**										
51	Commercial	$ 33,721		$ 33,721							PJA-4E
52	Industrial	$ -			$ -						PJA-4E
53	Residential	$ 268,155	$ 268,155								PJA-4E
54	Total Or	$ 301,876	$ 268,155	$ 33,721	$ -	$ -	$ -	$ -	$ -	$ -	
55	Cost Per Customer		$ 3.96	$ 3.30	$ -	$ -	$ -	$ -	$ -	$ -	
56											
57	**Total Customer O&M**	**$ 2,178,414**	**$ 1,884,089**	**$ 277,833**	**$ 3,604**	**$ 2,537**	**$ 8,511**	**$ 230**	**$ 920**	**$ 690**	
58											
59											
60	Gas Control O&M Allocation To Non-Core						45.4%	38.8%		15.8%	PJA-4F

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 505

Summary of Revenue by Rate Class

Cascade Natural Gas Corporation
Oregon Jurisdiction
Test Year Ended December 31, 2019

Summary of Revenue by Rate Class
Present and Proposed Rates

Customer Class	Revenues						
		Pro Forma		Proposed		$ Difference	% Difference
Residential - 101							
Basic Service Charge	$	4,062,245	$	4,874,694	$	812,449	20%
Delivery Charge		17,727,500		20,399,778		2,672,278	15%
Rounding Difference		-		(114)		(114)	
Total 101 Revenue	$	21,789,745	$	25,274,358	$	3,484,613	16%
Commercial - 104							
Basic Service Charge	$	1,227,330	$	1,472,796	$	245,466	20%
Delivery Charge		7,849,591		7,825,464		(24,127)	0%
Rounding Difference		-		56		56	
Total 104 Revenue	$	9,076,921	$	9,298,316	$	221,395	2%
Industrial - 105							
Basic Service Charge	$	54,360	$	63,420	$	9,060	17%
Delivery Charge		721,899		1,025,242		303,343	42%
Rounding Difference		-		2		2	
Total 105 Revenue	$	776,259	$	1,088,664	$	312,406	40%
Large Volume - 111							
Basic Service Charge	$	30,000	$	34,560	$	4,560	n/a
Delivery Charge		477,266		482,000		4,734	1%
Rounding Difference		-		(15)		(15)	
Total 111 Revenue	$	507,266	$	516,546	$	9,280	2%
General Distribution - 163							
Basic Service Charge	$	277,500	$	319,236	$	41,736	15%
Demand Charge	$	-	$	-	$	-	n/a
Delivery Charge		2,534,724		2,973,123		438,399	17%
Rounding Difference		-		15		15	
Total 163 Revenue	$	2,812,224	$	3,292,373	$	480,149	17%
Special Contract 902-2							
Basic Service Charge	$	6,000	$	8,628	$	2,628	44%
Demand Charge	$	1,085,999	$	685,992	$	(400,007)	-37%
Delivery Charge		271,760		669,203		397,443	146%
Rounding Difference		-		(64)		(64)	
Total 902-2 Revenue	$	1,363,759	$	1,363,759	$	-	0%
Interruptible - 170							
Basic Service Charge	$	14,400	$	14,400	$	-	n/a
Delivery Charge		237,322		237,322		-	0%
Rounding Difference		-		(0)		(0)	
Total 170 Revenue	$	251,722	$	251,722	$	-	0%
Special Contracts - 9xx							
Basic Service Charge	$	22,500	$	22,500	$	-	0%
Delivery Charge		280,056		280,056		-	0%
Demand Charge		82,800		82,800		-	0%
Rounding Difference		-		-		-	
Total 9xx Revenue	$	385,356	$	385,356	$	-	0%
TOTAL	**$**	**36,963,252**	**$**	**41,471,094**	**$**	**4,507,842**	

CNGC/506
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 506

Analysis of Revenue by Detailed Rate Schedule

Cascade Natural Gas Corporation | **CNGC/506**
Oregon Jurisdiction | **Archer/1**
Test Year Ended December 31, 2019 | 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	812,449	$5.00	$ 4,062,245	$6.00	$ 4,874,694	$ 812,449	20%
Delivery Charge	47,916,047	$0.36997	$ 17,727,500	$0.42574	$ 20,399,778	$ 2,672,278	15%
Rounding Difference					$ (114)	$ (114)	
Total 101 Revenue			**$ 21,789,745**		**$ 25,274,358**	**$ 3,484,613**	16%
Commercial - 104							
Basic Service Charge	122,733	$10.00	$ 1,227,330	$12.00	$ 1,472,796	$ 245,466	20%
Delivery Charge	30,931,912	$0.25377	$ 7,849,591	$0.25299	$ 7,825,464	$ (24,127)	0%
Rounding Difference					$ 56	$ 56	
Total 104 Revenue			**$ 9,076,921**		**$ 9,298,316**	**$ 221,395**	2%
Industrial - 105							
Basic Service Charge	1,812	$30.00	$ 54,360	$35.00	$ 63,420	$ 9,060	17%
Delivery Charge	3,196,788	$0.22582	$ 721,899	$0.32071	$ 1,025,242	$ 303,343	42%
Rounding Difference					$ 2	$ 2	
Total 105 Revenue			**$ 776,259**		**$ 1,088,664**	**$ 312,406**	40%
Large Volume - 111							
Basic Service Charge	240	$125.00	$ 30,000	$144.00	$ 34,560	$ 4,560	15%
Delivery Charge	3,015,329	$0.15828	$ 477,266	$0.15985	$ 482,000	$ 4,734	1%
Rounding Difference					$ (15)	$ (15)	
Total 111 Revenue			**$ 507,266**		**$ 516,546**	**$ 9,280**	2%
General Distribution - 163							
Basic Service Charge	444	$625.00	$ 277,500	$719.00	$ 319,236	$ 41,736	15%
Contract Demand Charge	-	$0.10000	$ -	$0.10000	$ -	$ -	n/a
Delivery Charge - first 10,000 therms	4,076,363	$0.12833	$ 523,111	$0.15052	$ 613,574	$ 90,463	17%
Delivery Charge - next 10,000 therms	3,246,559	$0.11577	$ 375,841	$0.13579	$ 440,850	$ 65,009	17%
Delivery Charge - next 30,000 therms	5,803,063	$0.10877	$ 631,205	$0.12758	$ 740,355	$ 109,150	17%
Delivery Charge - next 50,000 therms	5,906,089	$0.06680	$ 394,544	$0.07836	$ 462,801	$ 68,257	17%
Delivery Charge - next 400,000 therms	17,280,519	$0.03389	$ 585,602	$0.03975	$ 686,901	$ 101,298	17%
Delivery Charge - next 500,000 therms	1,344,696	$0.01816	$ 24,420	$0.02130	$ 28,642	$ 4,222	17%
Delivery Charge - over 1,000,000 therms	-	$0.01816		$0.00145	$ -	$ -	
Rounding Difference					$ 15	$ 15	
Total 163 Revenue			**$ 2,812,224**		**$ 3,292,373**	**$ 480,149**	17%
Special Contract 902-2							
Basic Service Charge	12	$500.00	$ 6,000	$719.00	$ 8,628	$ 2,628	44%
Contract Demand Charge - existing	10,800,000	$0.10056	$ 1,085,999				
Contract Demand Charge - proposed	6,859,920		$ -	$0.10000	$ 685,992	$ (400,007)	-37%
Delivery Charge - first 10,000 therms	120,000	$0.00164	$ 196	$0.15052	$ 18,062	$ 17,866	9094%
Delivery Charge - next 10,000 therms	120,000	$0.00164	$ 196	$0.13579	$ 16,295	$ 16,098	8195%
Delivery Charge - next 30,000 therms	360,000	$0.00164	$ 589	$0.12758	$ 45,929	$ 45,339	7693%
Delivery Charge - next 50,000 therms	600,000	$0.00164	$ 982	$0.07836	$ 47,016	$ 46,034	4687%
Delivery Charge - next 400,000 therms	4,800,000	$0.00164	$ 7,858	$0.03975	$ 190,800	$ 182,942	2328%
Delivery Charge - next 500,000 therms	6,000,000	$0.00164	$ 9,823	$0.02130	$ 127,800	$ 117,977	1201%
Delivery Charge - over 1,000,000 therms	154,000,802	$0.00164	$ 252,115	$0.00145	$ 223,301	$ (28,814)	-11%
Rounding Difference					$ (64)	$ (64)	
Total Special Contract 902-2 Revenue			**$ 1,363,759**		**$ 1,363,759**	**$ -**	0%
Interruptible - 170							
Basic Service Charge	48	$300.00	$ 14,400	$300.00	$ 14,400	$ -	0%
Delivery Charge	1,917,597	$0.12376	$ 237,322	$0.12376	$ 237,322	$ -	0%
Rounding Difference					$ (0)	$ (0)	
Total 170 Revenue			**$ 251,722**		**$ 251,722**	**$ (0)**	0%

*** Delivery Charge units are in therms**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 507

Residential Impact by Month

Residential - 101

Line No.	(a)	(b)	(c)	(d)
			Present Rates	Proposed Rates
1	Basic Service Charge		$5.00	$6.00
2	Delivery Charge		$0.36997	$0.42574
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	114	$ 93.53	$ 100.89	$ 7.36	7.87%
5	February	94	$ 78.00	$ 84.24	$ 6.24	8.00%
6	March	71	$ 60.14	$ 65.10	$ 4.96	8.25%
7	April	51	$ 44.61	$ 48.45	$ 3.84	8.62%
8	May	33	$ 30.63	$ 33.47	$ 2.84	9.27%
9	June	21	$ 21.31	$ 23.48	$ 2.17	10.19%
10	July	16	$ 17.43	$ 19.32	$ 1.89	10.86%
11	August	16	$ 17.43	$ 19.32	$ 1.89	10.86%
12	September	24	$ 23.64	$ 25.98	$ 2.34	9.89%
13	October	50	$ 43.83	$ 47.62	$ 3.79	8.64%
14	November	87	$ 72.56	$ 78.41	$ 5.85	8.06%
15	December	122	$ 99.74	$ 107.55	$ 7.80	7.82%
16	Total	699	$ 602.82	$ 653.81	$ 50.98	
17	Monthly Average		$ 50.24	$ 54.48	$ 4.25	8.46%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 508

Impact of Recommended Rate Changes

Residential - 101

Line No.	(a)	(b)	(c)	(d)	(e)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$5.00	$6.00		
2	Delivery Charge	$0.36997	$0.42574		
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	$5.00	$6.00	$1.00	20.00%
5	25	$24.41	$26.81	$2.39	9.81%
6	30	$28.30	$30.97	$2.67	9.45%
7	35	$32.18	$35.13	$2.95	9.17%
8	40	$36.06	$39.29	$3.23	8.96%
9	45	$39.95	$43.46	$3.51	8.79%
10	50	$43.83	$47.62	$3.79	8.64%
11	60	$51.59	$55.94	$4.35	8.42%
12	70	$59.36	$64.26	$4.90	8.26%
13	80	$67.13	$72.59	$5.46	8.14%
14	90	$74.89	$80.91	$6.02	8.04%
15	100	$82.66	$89.23	$6.58	7.96%
16	110	$90.42	$97.56	$7.13	7.89%
17	120	$98.19	$105.88	$7.69	7.83%
18	130	$105.95	$114.20	$8.25	7.79%
19	140	$113.72	$122.53	$8.81	7.75%
20	150	$121.49	$130.85	$9.37	7.71%
21	160	$129.25	$139.17	$9.92	7.68%
22	170	$137.02	$147.50	$10.48	7.65%
23	180	$144.78	$155.82	$11.04	7.62%
24	190	$152.55	$164.14	$11.60	7.60%
25	200	$160.31	$172.47	$12.15	7.58%
26	210	$168.08	$180.79	$12.71	7.56%
27	220	$175.85	$189.11	$13.27	7.55%
28	230	$183.61	$197.44	$13.83	7.53%
29	240	$191.38	$205.76	$14.38	7.52%
30	250	$199.14	$214.09	$14.94	7.50%

Commercial - 104

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$10.00	$12.00		
2	Delivery Charge	$0.25377	$0.25299		
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	$10.00	$12.00	$2.00	20.00%
5	50	$43.02	$44.98	$1.96	4.56%
6	60	$49.62	$51.58	$1.95	3.94%
7	70	$56.23	$58.17	$1.95	3.46%
8	80	$62.83	$64.77	$1.94	3.08%
9	90	$69.43	$71.36	$1.93	2.78%
10	100	$76.04	$77.96	$1.92	2.53%
11	110	$82.64	$84.55	$1.91	2.32%
12	120	$89.24	$91.15	$1.91	2.14%
13	130	$95.85	$97.75	$1.90	1.98%
14	140	$102.45	$104.34	$1.89	1.85%
15	150	$109.06	$110.94	$1.88	1.73%
16	160	$115.66	$117.53	$1.88	1.62%
17	170	$122.26	$124.13	$1.87	1.53%
18	180	$128.87	$130.73	$1.86	1.44%
19	190	$135.47	$137.32	$1.85	1.37%
20	200	$142.07	$143.92	$1.84	1.30%
21	250	$175.09	$176.90	$1.81	1.03%
22	300	$208.11	$209.88	$1.77	0.85%
23	350	$241.13	$242.86	$1.73	0.72%
24	400	$274.15	$275.84	$1.69	0.62%
25	450	$307.17	$308.82	$1.65	0.54%
26	500	$340.19	$341.80	$1.61	0.47%
27	600	$406.22	$407.75	$1.53	0.38%
28	700	$472.26	$473.71	$1.45	0.31%
29	800	$538.30	$539.67	$1.38	0.26%
30	1,000	$670.37	$671.59	$1.22	0.18%
31	1,250	$835.46	$836.49	$1.03	0.12%
32	1,500	$1,000.56	$1,001.39	$0.83	0.08%
33	1,750	$1,165.65	$1,166.28	$0.63	0.05%
34	2,000	$1,330.74	$1,331.18	$0.44	0.03%
35	2,500	$1,660.93	$1,660.98	$0.05	0.00%
36	3,000	$1,991.11	$1,990.77	-$0.34	-0.02%
37	3,500	$2,321.30	$2,320.57	-$0.73	-0.03%
38	4,000	$2,651.48	$2,650.36	-$1.12	-0.04%

Industrial - 105

Line No.	(a)	(b) Present Rates	(d) Proposed Rates	(e)	(f)
1	Basic Service Charge	$30.00	$35.00		
2	Delivery Charge	$0.22582	$0.32071		
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	$30.00	$35.00	$5.00	16.67%
5	100	$93.24	$107.73	$14.49	15.54%
6	200	$156.48	$180.46	$23.98	15.32%
7	300	$219.73	$253.19	$33.47	15.23%
8	400	$282.97	$325.92	$42.96	15.18%
9	500	$346.21	$398.66	$52.45	15.15%
10	600	$409.45	$471.39	$61.93	15.13%
11	700	$472.69	$544.12	$71.42	15.11%
12	800	$535.94	$616.85	$80.91	15.10%
13	900	$599.18	$689.58	$90.40	15.09%
14	1,000	$662.42	$762.31	$99.89	15.08%
15	1,100	$725.66	$835.04	$109.38	15.07%
16	1,200	$788.90	$907.77	$118.87	15.07%
17	1,300	$852.15	$980.50	$128.36	15.06%
18	1,400	$915.39	$1,053.23	$137.85	15.06%
19	1,500	$978.63	$1,125.97	$147.34	15.06%
20	2,000	$1,294.84	$1,489.62	$194.78	15.04%
21	2,500	$1,611.05	$1,853.28	$242.23	15.04%
22	3,000	$1,927.26	$2,216.93	$289.67	15.03%
23	3,500	$2,243.47	$2,580.59	$337.12	15.03%
24	4,000	$2,559.68	$2,944.24	$384.56	15.02%
25	5,000	$3,192.10	$3,671.55	$479.45	15.02%
26	6,000	$3,824.52	$4,398.86	$574.34	15.02%
27	7,000	$4,456.94	$5,126.17	$669.23	15.02%
28	8,000	$5,089.36	$5,853.48	$764.12	15.01%
29	9,000	$5,721.78	$6,580.79	$859.01	15.01%
30	10,000	$6,354.20	$7,308.10	$953.90	15.01%
31	12,500	$7,935.25	$9,126.38	$1,191.13	15.01%
32	15,000	$9,516.30	$10,944.65	$1,428.35	15.01%
33	17,500	$11,097.35	$12,762.93	$1,665.58	15.01%
34	20,000	$12,678.40	$14,581.20	$1,902.80	15.01%
35	25,000	$15,840.50	$18,217.75	$2,377.25	15.01%
36	30,000	$19,002.60	$21,854.30	$2,851.70	15.01%
37	35,000	$22,164.70	$25,490.85	$3,326.15	15.01%
38	40,000	$25,326.80	$29,127.40	$3,800.60	15.01%
39	45,000	$28,488.90	$32,763.95	$4,275.05	15.01%
40	50,000	$31,651.00	$36,400.50	$4,749.50	15.01%
41	60,000	$37,975.20	$43,673.60	$5,698.40	15.01%
42	70,000	$44,299.40	$50,946.70	$6,647.30	15.01%
43	80,000	$50,623.60	$58,219.80	$7,596.20	15.01%
44	90,000	$56,947.80	$65,492.90	$8,545.10	15.01%
45	100,000	$63,272.00	$72,766.00	$9,494.00	15.01%

Large Volume - 111

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$125.00	$144.00		
2	Delivery Charge	$0.15828	$0.15985		
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	$125.00	$144.00	$19.00	
5	100	$181.49	$200.65	$19.16	10.56%
6	200	$237.98	$257.29	$19.31	8.12%
7	300	$294.46	$313.94	$19.47	6.61%
8	400	$350.95	$370.58	$19.63	5.59%
9	500	$407.44	$427.23	$19.79	4.86%
10	600	$463.93	$483.87	$19.94	4.30%
11	700	$520.42	$540.52	$20.10	3.86%
12	800	$576.90	$597.16	$20.26	3.51%
13	900	$633.39	$653.81	$20.41	3.22%
14	1,000	$689.88	$710.45	$20.57	2.98%
15	1,100	$746.37	$767.10	$20.73	2.78%
16	1,200	$802.86	$823.74	$20.88	2.60%
17	1,300	$859.34	$880.39	$21.04	2.45%
18	1,400	$915.83	$937.03	$21.20	2.31%
19	1,500	$972.32	$993.68	$21.36	2.20%
20	2,000	$1,254.76	$1,276.90	$22.14	1.76%
21	2,500	$1,537.20	$1,560.13	$22.93	1.49%
22	3,000	$1,819.64	$1,843.35	$23.71	1.30%
23	3,500	$2,102.08	$2,126.58	$24.49	1.17%
24	4,000	$2,384.52	$2,409.80	$25.28	1.06%
25	5,000	$2,949.40	$2,976.25	$26.85	0.91%
26	6,000	$3,514.28	$3,542.70	$28.42	0.81%
27	7,000	$4,079.16	$4,109.15	$29.99	0.74%
28	8,000	$4,644.04	$4,675.60	$31.56	0.68%
29	9,000	$5,208.92	$5,242.05	$33.13	0.64%
30	10,000	$5,773.80	$5,808.50	$34.70	0.60%
31	12,500	$7,186.00	$7,224.63	$38.62	0.54%
32	15,000	$8,598.20	$8,640.75	$42.55	0.49%
33	17,500	$10,010.40	$10,056.88	$46.47	0.46%
34	20,000	$11,422.60	$11,473.00	$50.40	0.44%
35	25,000	$14,247.00	$14,305.25	$58.25	0.41%
36	30,000	$17,071.40	$17,137.50	$66.10	0.39%
37	35,000	$19,895.80	$19,969.75	$73.95	0.37%
38	40,000	$22,720.20	$22,802.00	$81.80	0.36%
39	45,000	$25,544.60	$25,634.25	$89.65	0.35%
40	50,000	$28,369.00	$28,466.50	$97.50	0.34%
41	60,000	$34,017.80	$34,131.00	$113.20	0.33%
42	70,000	$39,666.60	$39,795.50	$128.90	0.32%
43	80,000	$45,315.40	$45,460.00	$144.60	0.32%
44	90,000	$50,964.20	$51,124.50	$160.30	0.31%
45	100,000	$56,613.00	$56,789.00	$176.00	0.31%

Interruptible - 170

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$300.00	$300.00		
2	Delivery Charge	$0.12376	$0.12376		
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	$300.00	$300.00	$0.00	
5	500	$565.18	$565.18	$0.00	0.00%
6	1,000	$830.36	$830.36	$0.00	0.00%
7	1,500	$1,095.54	$1,095.54	$0.00	0.00%
8	2,000	$1,360.72	$1,360.72	$0.00	0.00%
9	2,500	$1,625.90	$1,625.90	$0.00	0.00%
10	3,000	$1,891.08	$1,891.08	$0.00	0.00%
11	3,500	$2,156.26	$2,156.26	$0.00	0.00%
12	4,000	$2,421.44	$2,421.44	$0.00	0.00%
13	4,500	$2,686.62	$2,686.62	$0.00	0.00%
14	5,000	$2,951.80	$2,951.80	$0.00	0.00%
15	6,000	$3,482.16	$3,482.16	$0.00	0.00%
16	7,000	$4,012.52	$4,012.52	$0.00	0.00%
17	8,000	$4,542.88	$4,542.88	$0.00	0.00%
18	9,000	$5,073.24	$5,073.24	$0.00	0.00%
19	10,000	$5,603.60	$5,603.60	$0.00	0.00%
20	11,000	$6,133.96	$6,133.96	$0.00	0.00%
21	12,000	$6,664.32	$6,664.32	$0.00	0.00%
22	13,000	$7,194.68	$7,194.68	$0.00	0.00%
23	14,000	$7,725.04	$7,725.04	$0.00	0.00%
24	15,000	$8,255.40	$8,255.40	$0.00	0.00%
25	17,500	$9,581.30	$9,581.30	$0.00	0.00%
26	20,000	$10,907.20	$10,907.20	$0.00	0.00%
27	22,500	$12,233.10	$12,233.10	$0.00	0.00%
28	25,000	$13,559.00	$13,559.00	$0.00	0.00%
29	30,000	$16,210.80	$16,210.80	$0.00	0.00%
30	35,000	$18,862.60	$18,862.60	$0.00	0.00%
31	40,000	$21,514.40	$21,514.40	$0.00	0.00%
32	45,000	$24,166.20	$24,166.20	$0.00	0.00%
33	50,000	$26,818.00	$26,818.00	$0.00	0.00%
34	60,000	$32,121.60	$32,121.60	$0.00	0.00%
35	70,000	$37,425.20	$37,425.20	$0.00	0.00%
36	80,000	$42,728.80	$42,728.80	$0.00	0.00%
37	90,000	$48,032.40	$48,032.40	$0.00	0.00%
38	100,000	$53,336.00	$53,336.00	$0.00	0.00%
39	125,000	$66,595.00	$66,595.00	$0.00	0.00%
40	150,000	$79,854.00	$79,854.00	$0.00	0.00%
41	175,000	$93,113.00	$93,113.00	$0.00	0.00%
42	200,000	$106,372.00	$106,372.00	$0.00	0.00%
43	225,000	$119,631.00	$119,631.00	$0.00	0.00%
44	250,000	$132,890.00	$132,890.00	$0.00	0.00%

CNGC/509
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 509

Proposed Tariff Sheets

SCHEDULE 101
GENERAL RESIDENTIAL SERVICE RATE

APPLICABILITY
This schedule is available to residential customers.

RATE

Basic Service Charge		$6.00	per month	(I)
Delivery Charge		$0.42574	per therm	(I)
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	
Schedule 191	Temporary Gas Cost Rate	$0.066015	per therm	
Schedule 192	Intervenor Funding	$0.001570	per therm	
Schedule 193	Conservation Alliance Plan	($0.024120)	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Cost	$0.00322	per therm	(I)
Schedule 198	Unprotected EDIT	($0.007203)	per therm	
Schedule 199	Interim Period	($0.018290)	per therm	
	Total	$0.786923	per therm	(I)

MINIMUM CHARGE
Basic Service Charge $6.00 (I)

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		$12.00	per month	(I)
Delivery Charge		$0.25299	per therm	(R)
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	
Schedule 191	Temporary Gas Cost Rate	$0.066015	per therm	
Schedule 192	Intervenor Funding	$0.000000	per therm	
Schedule 193	Conservation Alliance Plan	($0.024120)	per therm	
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Cost	$0.00322	per therm	(I)
Schedule 198	Unprotected EDIT	($0.004624)	per therm	
Schedule 199	Interim Period	($0.011838)	per therm	
	Total	$0.621634	per therm	(I)

MINIMUM CHARGE
Basic Service Charge $12.00 (I)

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		$35.00	per month	(I)
Delivery Charge		$0.32071	per therm	(I)
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	
Schedule 191	Temporary Gas Cost Rate	$0.066015	per therm	
Schedule 192	Intervenor Funding	$0.001110	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	$0.00322	per therm	(I)
Schedule 198	Unprotected EDIT	($0.003587)	per therm	
Schedule 199	Interim Period	($0.009862)	per therm	
	Total	$0.717597	per therm	(I)

MINIMUM CHARGE
Basic Service Charge $35.00 (I)

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		$144.00	per month	(I)
Delivery Charge		$0.15985	per therm	(I)
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	
Schedule 191	Temporary Gas Cost Rate	$0.066015	per therm	
Schedule 192	Intervenor Funding	$0.001110	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	$0.00322	per therm	(I)
Schedule 198	Unprotected EDIT	($0.002755)	per therm	
Schedule 199	Interim Period	($0.006836)	per therm	
	Total	$0.560595	per therm	(I)

MINIMUM CHARGE
Basic Service Charge $144.00 (I)

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.

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.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

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** $719.00 per month (I)

B. **Distribution Charge** for All Therms Delivered Per Month

		Base Rate	Sch. 192	Sch. 196	Sch 197	Sch 198	Sch 199	Billing Rate		
First	10,000	0.15052	$0.001110	$0.000	$0.00322	($0.001140)	($0.003020)	0.15069	per therm	(I)
Next	10,000	0.13579	$0.001110	$0.000	$0.00322	($0.001140)	($0.003020)	0.13596	per therm	(I)
Next	30,000	0.12758	$0.001110	$0.000	$0.00322	($0.001140)	($0.003020)	0.12775	per therm	(I)
Next	50,000	0.07836	$0.001110	$0.000	$0.00322	($0.001140)	($0.003020)	0.07853	per therm	(I)
Next	400,000	0.03975	$0.001110	$0.000	$0.00322	($0.001140)	($0.003020)	0.03992	per therm	(I)
Next	500,000	0.02130	$0.001110	$0.000	$0.00322	($0.001140)	($0.003020)	0.02147	per therm	(I)
Over	1,000,000	0.02130	$0.001110	$0.000	$0.00322	($0.001140)	($0.003020)	0.02147	per therm	(I)

C. **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**

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.

(continued)

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		$0.12376	per therm	
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	
Schedule 191	Gas Cost Rate Adjustment	$0.066015	per therm	
Schedule 192	Intervenor Funding Adjustment	$0.001110	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	$0.00322	per therm	(I)
Schedule 198	Unprotected EDIT	($0.002044)	per therm	
Schedule 199	Interim Period	($0.005248)	per therm	
All Therms per Month:	Total Per Therm Rate	$0.526804	per therm	(I)

MINIMUM CHARGE
Basic Service Charge $300.00

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. (continued)

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. 20-XXX to recover $1,204,590 over a three-year period of time. (C)

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

$0.00322	per therm	(I)

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 800
Biomethane Receipt Services

PURPOSE:
This Schedule establishes terms and conditions whereby qualifying producers of biomethane (Biomethane Producer) may request either a newly constructed interconnection to the Company's distribution system or increased capacity at an existing interconnection point for the purpose of injecting qualifying biomethane on the Company's distribution system.

APPLICABILITY:
Service under this Schedule is available to Biomethane Producers who meet all of the following conditions:

1) The Biomethane Producer must meet the following credit screening criteria as established for nonresidential customers in Rule 2;
2) The raw biogas from which the biomethane is produced must be from one or a mix of the following feedstocks: a) agricultural byproducts; b) wastewater; c) landfill waste; or d) food and beverage waste;
3) The Company, in its sole opinion, has determined that injection of biomethane will not jeopardize or interfere with normal operation of the Company's distribution system and its provision of gas service to its customers;
4) Prior to the Company's building an interconnection, the Biomethane Producer must demonstrate to the satisfaction of Company that it has secured end user(s) that are Company's customers who agree to purchase all the estimated biomethane production; and
5) The Biomethane Producer must comply with all terms and conditions preceding biomethane receipt services as established herein, including:
    a. Paying all costs for the Interconnection Capacity Study and the Engineering Study as well as all interconnect costs; and
    b. Executing a Biomethane Receipt Services Agreement for ongoing receipt services under this Schedule.

MONTHLY CHARGES
A Biomethane Producer receiving service under this Schedule shall receive the following monthly charges:

Basic Service Charge $2,500.00

Blocks By Therms		Base Rate	Odorant	Sch. 192	Sch. 197	Sch. 198	Sch. 199	Billing Rate	
First	10,000	.15052	$0.0002125	$0.001110	$0.00322	($0.001140)	($0.003020)	.1509025	(I)
Next	10,000	.13579	$0.0002125	$0.001110	$0.00322	($0.001140)	($0.003020)	.1361725	
Next	30,000	.12758	$0.0002125	$0.001110	$0.00322	($0.001140)	($0.003020)	.1279625	
Next	50,000	.07836	$0.0002125	$0.001110	$0.00322	($0.001140)	($0.003020)	.0787425	
Next	400,000	.03975	$0.0002125	$0.001110	$0.00322	($0.001140)	($0.003020)	.0401325	
Over	500,000	.02130	$0.0002125	$0.001110	$0.00322	($0.001140)	($0.003020)	.0216825	(I)

(continued)

CNGC/510
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 390

Pamela J. Archer
Exhibit No. 510

Redlined Tariff Sheets

Formatted: Font: 12 pt, Not Bold

Formatted: Font: Not Bold

SCHEDULE 101
GENERAL RESIDENTIAL SERVICE RATE

APPLICABILITY
This schedule is available to residential customers.

RATE

Basic Service Charge		$6~~5~~.00	per month	
Delivery Charge		$0.42574~~369970~~	per therm	
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	~~(R)~~
Schedule 191	Temporary Gas Cost Rate	$0.066015	per therm	~~(I)~~
Schedule 192	Intervenor Funding	$0.001570	per therm	~~(I)~~
Schedule 193	Conservation Alliance Plan	($0.024120)	per therm	~~(R)~~
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Cost	$0.00~~0303~~322	per therm	
Schedule 198	Unprotected EDIT	($0.007203)	per therm	~~(R)~~
Schedule 199	Interim Period	($0.018290)	per therm	~~(N)~~
	Total	$0.786923~~728236~~	per therm	(I)

MINIMUM CHARGE
Basic Service Charge $6~~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.

CASCADE NATURAL GAS CORPORATION **~~Fourth~~ Fifth Revision of Sheet No. 104.1**
Canceling
P.U.C. OR. No. 10 **~~Third~~ Fourth Revision of Sheet No. 104.1**

SCHEDULE 104
GENERAL COMMERCIAL SERVICE RATE

APPLICABILITY
This schedule is available to commercial customers.

RATE

Basic Service Charge		$12~~0~~.00	per month	
Delivery Charge		$0.25299~~253770~~	per therm	
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	~~(R)~~
Schedule 191	Temporary Gas Cost Rate	$0.066015	per therm	~~(I)~~
Schedule 192	Intervenor Funding	$0.000000	per therm	
Schedule 193	Conservation Alliance Plan	($0.024120)	per therm	~~(R)~~
Schedule 196	Oregon Earnings Sharing	$0.000000	per therm	
Schedule 197	Environmental Remediation Cost	$0.00~~0~~3~~03~~22	per therm	(I)
Schedule 198	Unprotected EDIT	($0.004624)	per therm	~~(R)~~
Schedule 199	Interim Period	($0.011838)	per therm	~~(N)~~
	Total	$0.621634~~619497~~	per therm	(I)

MINIMUM CHARGE
Basic Service Charge $12~~0~~.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.

CASCADE NATURAL GAS CORPORATION — **~~Fourth~~ Fifth Revision of Sheet No. 105.1**

Canceling

P.U.C. OR. No. 10 — **~~Third~~ Fourth Revision of Sheet No. 105.1**

SCHEDULE 105
GENERAL INDUSTRIAL SERVICE RATE

APPLICABILITY

This schedule is available to industrial customers.

RATE

Basic Service Charge		$35~~0~~.00	per month	
Delivery Charge		$0.32071~~225820~~	per therm	
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	~~(R)~~
Schedule 191	Temporary Gas Cost Rate	$0.066015	per therm	~~(I)~~
Schedule 192	Intervenor Funding	$0.001110	per therm	~~(I)~~
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~~00322	per therm	(I)
Schedule 198	Unprotected EDIT	($0.003587)	per therm	~~(R)~~
Schedule 199	Interim Period	($0.009862)	per therm	~~(N)~~
	Total	$0.717597~~619790~~	per therm	(I)

Formatted Table

MINIMUM CHARGE

Basic Service Charge $35~~0~~.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.

CASCADE NATURAL GAS CORPORATION **~~F~~Si~~f~~xth Revision of Sheet No. 111.1**
Canceling
P.U.C. OR. No. 10 **~~Fourth~~ Fifth Revision of Sheet No. 111.1**

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		$144~~25~~.00	per month	
Delivery Charge		$0.15985~~158280~~	per therm	
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	~~(R)~~
Schedule 191	Temporary Gas Cost Rate	$0.066015	per therm	~~(I)~~
Schedule 192	Intervenor Funding	$0.001110	per therm	~~(I)~~
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~~00322	per therm	(I)
Schedule 198	Unprotected EDIT	($0.002755)	per therm	~~(R)~~
Schedule 199	Interim Period	($0.006836)	per therm	~~(N)~~
	Total	$0.560595~~556108~~	per therm	(I)

MINIMUM CHARGE

Basic Service Charge $144~~25~~.00

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.

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.

(continued)

CASCADE NATURAL GAS CORPORATION ~~Fifth~~ Sixth **Revision of Sheet No. 163.1**

Canceling

P.U.C. OR. No. 10 ~~Fourth~~ Fifth **Revision of Sheet No. 163.1**

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

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** $719~~625~~.00 per month

B. **Distribution Charge** for All Therms Delivered Per Month

		Base Rate	Sch. 192	Sch. 196	Sch 197	Sch 198	Sch 199	Billing Rate		
										~~(N)~~
First	10,000	0.15052~~$0.128328~~	$0.001110	$0.000	$0.~~000303~~00322	($0.001140)	($0.003020)	0.15069~~$0.125581~~	per therm	~~(R)~~
Next	10,000	0.13579~~$0.115766~~	$0.001110	$0.000	$0.00322 ~~$0.000303~~	($0.001140)	($0.003020)	0.13596~~$0.113019~~	per ther	Formatted Table
Next	30,000	0.12758~~$0.108771~~	$0.001110	$0.000	$0.00322 ~~$0.000303~~	($0.001140)	($0.003020)	0.12775~~$0.106024~~	per therm	~~(R)~~
Next	50,000	0.07836~~$0.066803~~	$0.001110	$0.000	$0.00322 ~~$0.000303~~	($0.001140)	($0.003020)	0.07853~~$0.064056~~	per therm	~~(R)~~
Next	400,000	0.03975~~$0.033888~~	$0.001110	$0.000	$0.00322 ~~$0.000303~~	($0.001140)	($0.003020)	0.03992~~$0.031141~~	per therm	~~(R)~~
Next	500,000	0.02130~~$0.018160~~	$0.001110	$0.000	$0.00322 ~~$0.000303~~	($0.001140)	($0.003020)	0.02147~~$0.015413~~	per therm	~~(R)~~
Over	1,000,000	0.02130~~01~~45~~$0.018160~~	$0.001110	$0.000	$0.00322 ~~$0.000303~~	($0.001140)	($0.003020)	0.02147~~01~~62~~$0.015413~~	per therm	~~(R)~~

C. **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**

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.

(continued)

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		$0.12376~~123760~~	per therm	
OTHER CHARGES:				
Schedule 177	Cost of Gas (WACOG)	$0.339991	per therm	~~(R)~~
Schedule 191	Gas Cost Rate Adjustment	$0.066015	per therm	~~(I)~~
Schedule 192	Intervenor Funding Adjustment	$0.001110	per therm	~~(I)~~
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~~00322	per therm	(I) ~~(R)~~
Schedule 198	Unprotected EDIT	($0.002044)	per therm	~~(N)~~
Schedule 199	Interim Period	($0.005248)	per therm	(I)
All Therms per Month:	Total Per Therm Rate	$0.526804~~523887~~	per therm	

MINIMUM CHARGE
Basic Service Charge $300.00

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. (continued)

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~~20-XXX to recover $1,~~6~~204,~~00~~590 over a three-year period of time. (C)

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

$0.00~~0303~~322	per therm

(~~R~~I)

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.

CASCADE NATURAL GAS CORPORATION — **~~Fifth~~ Sixth Revision of Sheet No.800.1**
Canceling
P.U.C. OR. No. 10 — **~~Fourth~~ Fifth Revision of Sheet No. 800.1**

Schedule 800
Biomethane Receipt Services

PURPOSE:
This Schedule establishes terms and conditions whereby qualifying producers of biomethane (Biomethane Producer) may request either a newly constructed interconnection to the Company's distribution system or increased capacity at an existing interconnection point for the purpose of injecting qualifying biomethane on the Company's distribution system.

APPLICABILITY:
Service under this Schedule is available to Biomethane Producers who meet all of the following conditions:

1) The Biomethane Producer must meet the following credit screening criteria as established for nonresidential customers in Rule 2;
2) The raw biogas from which the biomethane is produced must be from one or a mix of the following feedstocks: a) agricultural byproducts; b) wastewater; c) landfill waste; or d) food and beverage waste;
3) The Company, in its sole opinion, has determined that injection of biomethane will not jeopardize or interfere with normal operation of the Company's distribution system and its provision of gas service to its customers;
4) Prior to the Company's building an interconnection, the Biomethane Producer must demonstrate to the satisfaction of Company that it has secured end user(s) that are Company's customers who agree to purchase all the estimated biomethane production; and
5) The Biomethane Producer must comply with all terms and conditions preceding biomethane receipt services as established herein, including:
   a. Paying all costs for the Interconnection Capacity Study and the Engineering Study as well as all interconnect costs; and
   b. Executing a Biomethane Receipt Services Agreement for ongoing receipt services under this Schedule.

MONTHLY CHARGES
A Biomethane Producer receiving service under this Schedule shall receive the following monthly charges:

Basic Service Charge $2,500.00

Blocks By Therms		Base Rate	Odorant	Sch. 192	Sch. 197	Sch. 198	Sch. 199	Billing Rate	
									(~~N~~)
First	10,000	.15052~~$0.128328~~	$0.0002125	$0.001110	$0.00322~~$0.000303~~	($0.001140)	($0.003020)	.1509025~~$0.125~~	(~~R~~I)
Next	10,000	.13579~~$0.115766~~	$0.0002125	$0.001110	$0.00322~~$0.000303~~	($0.001140)	($0.003020)	.1361725~~$0.113~~	
Next	30,000	.12758~~$0.108771~~	$0.0002125	$0.001110	$0.00322~~$0.000303~~	($0.001140)	($0.003020)	.1279625~~$0.106~~	
Next	50,000	.07836~~$0.066803~~	$0.0002125	$0.001110	$0.00322~~$0.000303~~	($0.001140)	($0.003020)	.0787425~~$0.064~~	
Next	400,000	.03975~~$0.033888~~	$0.0002125	$0.001110	$0.00322~~$0.000303~~	($0.001140)	($0.003020)	.0401325~~$0.031~~	
Over	500,000	.02130~~$0.018160~~	$0.0002125	$0.001110	$0.00322~~$0.000303~~	($0.001140)	($0.003020)	.0216825~~$0.015~~	(~~R~~I)

Formatted Table

(continued)