BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

DIRECT TESTIMONY OF Nicole A. Kivisto
REPRESENTING CASCADE NATURAL GAS CORPORATION

Cascade and Rate Case Overview

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I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. Please describe your duties and responsibilities with Cascade.

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

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

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

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

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. I will provide an overview of Cascade. I will also summarize the Company's rate request in this filing, the primary drivers of the need for rate relief, and provide some background on increasing costs facing the Company. My testimony will also describe measures the Company has taken to control costs and increase operating efficiencies. I will also introduce the other witnesses providing testimony on the Company's behalf.

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

A. Yes. Increasing rate base and operating expenses require Cascade to request an increase of $1,906,285 or 2.76%. This increase is based on an overall rate of return of 7.31%, with a capital structure common equity component of 49%, and a return on equity of 9.4%. The Company is using a forecasted test period of the calendar year 2016. The forecasted test period was selected as the most appropriate and supportable for the period during which rates will be in effect. Michael Parvinen provides further discussion regarding the test period in his 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. Ron Amen provides testimony supporting the cost study and rate spread issues.

Based on an average usage level of 55 therms per month, the average residential customer will see a bill increase of $2.07 per month from $50.58 to $52.66. This equates to an average increase of 4.10%.

III. OVERVIEW OF CASCADE

Q. Please briefly provide an overview of the Company.

A. Cascade provides natural gas distribution services in 96 communities in Washington and Oregon. Cascade serves 25 communities in Oregon, the largest of those communities are Bend, Baker City, and Pendleton. Cascade's headquarters are located in Kennewick, Washington. Cascade is wholly owned by MDU Resources, located in Bismarck, North Dakota. Cascade has 278,026 customers, of which 70,224 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 312 dedicated employees. Cascade became a subsidiary of MDU Resources in 2007.

IV. REASONS FOR RATE INCREASE REQUEST

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

A. The primary factor is pipeline replacement costs. In 2011, as required by the Department of Transportation, Cascade prepared a process for evaluating the physical condition of its distribution pipeline. Through the implementation of the evaluation process, Cascade identified a number of areas of concern that could eventually impact the Company's ability to provide safe and reliable service to its customers. As a result, Cascade has devoted a tremendous amount of capital to pipeline replacement and improvement projects over the last four 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 has remained virtually untouched since its acquisition. Cascade is currently entering year five of a multi-year plan to completely replace the original system. Cascade financed the first three years of the multi-year plan using funds from merger savings and other synergies it obtained in the acquisition by MDU Resources.

Q. How much of the current requested increase of $1.9 million is due to 2016 capital investments?

A. $1.6 million. This means that 84% of the increase is attributable to rate base increases.

Q. Please identify other drivers of the proposed increase.

A. The other single biggest cost driver is the actual implementation of the depreciation rates approved in docket UM 1727, effective January 1, 2016. The actual impact of the depreciation rates is an increase to the revenue requirement of $400,000.

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

A. Cascade has a history of mitigating increased cost pressures in order to avoid filing rate cases. Since the acquisition by MDU Resources, Cascade has found synergy savings in the form of joint senior management, a unified call center, a joint billing facility and process, and uniform accounting and customer information system software. The utility group continues to look for ways to acquire such synergies including a new Gas Management System (GMS).

V. CUSTOMER SUPPORT PROGRAMS

Q. Can you identify 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 Helps 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.

Cascade filed for and received a two-year extension of its pilot Conservation Achievement Tariff (CAT) in docket ADV 157, which supplements the low-income conservation program by providing full funding of conservation measures thus allowing for substantially more low-income homes to be weatherized.

Q. Please briefly describe the Budget Payment Plan.

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

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

A. As of December 31, 2015, there are 5,349 or 7.62% of Oregon customers participating in the Budget Payment Plan.

VI. OTHER COMPANY WITNESSES

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

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

Mr. Michael Parvinen, Director – Regulatory Affairs, will discuss the overall revenue requirement, the Company's capital structure, the proposed cost of embedded debt, and the overall rate of return. He will also explain the Company's philosophy underlying its basic charge request in this case.

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

Ms. Pamela Archer, Supervisor – Regulatory Analysis, discusses the base year revenue proof, 2016 proposed revenue adjustment, and the Company's proposal to replace its current tariff, P.U.C. Or. No. 9, with a revised and updated tariff, P.U.C. OR. No. 10.

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

A. Yes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

DIRECT TESTIMONY OF MICHAEL P. PARVINEN
REPRESENTING CASCADE NATURAL GAS CORPORATION

Revenue Requirement

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

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

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

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

Q. How long have you been employed by Cascade?

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

Q. What are your educational and professional qualifications?

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

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

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

Rate Seminar in 1987 and the 1988 Annual Regulatory Studies Program, sponsored by the National Association of Regulatory Utility Commissioners.

II. SCOPE AND SUMMARY OF TESTIMONY

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

A. The purpose of my testimony is fourfold:

- First, I address the revenue requirements and supporting calculations;
- Second, I explain and support the capital structure and rate of return requested in this proceeding;
- Third, I explain the plant additions; and
- Fourth, I present Cascade's approach to its proposed basic charges for residential and commercial customers.

Q. Are you sponsoring any exhibits in this proceeding?

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

- Exhibit CNG/201 Results of Operation Summary Sheet
- Exhibit CNG/202 Revenue Requirement Calculation
- Exhibit CNG/203 Conversion Factor Calculation
- Exhibit CNG/204 Proposed Adjustments to Base Year Results
- Exhibit CNG/205 2016 Plant Additions
- Exhibit CNG/206 Decoupling Allowed Margin per Customer

III. REVENUE REQUIREMENT AND SUPPORTING CALCULATIONS

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

A. After taking into account all proposed adjustments, the forecast rate of return (ROR) is 5.99%, as shown in Exhibit CNG/201. The incremental revenue necessary to achieve the recommended ROR of 7.31% is $1,906,285, also shown in Exhibit CNG/201. The calculation of the incremental revenue is also provided in Exhibit CNG/202. The overall base revenue increase requested is 2.76%.

Q. Please explain your result of operations.

A. The Company's result of operations is summarized in Exhibit CNG/201. The figures shown in column (1) are the actual Oregon booked figures for the base year, which is the twelve months ended December 31, 2015. Column (2) is the summation of all adjustments, both restating and forecasted, to achieve the test period results. Each adjustment that is included in column (2) is identified separately in Exhibit CNG/204, and is described later in my testimony. Column (3) is the sum of columns (1) and (2), and represents the expected results of operations in the test period absent any rate change. Column (4) identifies the proposed revenue change and the net income impact of the revenue increase.[1] Column (5) is the results of operation expected during the test period with proposed rates.

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

A. Cascade is proposing calendar year 2016 as the test period. As a practical matter, rates are anticipated to go into effect March 1, 2017; consequently, 2017 will be the first year rates will be in effect. However, we are unable to project 2017 revenues and costs with any accuracy.

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

[1] The proposed revenue increase is also calculated in Exhibit CNG/202.

A. No. Although costs are anticipated to exceed growth in revenues from new customers in 2017, Cascade is opting to keep this filing as simple as possible by excluding such projections.

Q. Are 2017 revenue increases due to increased customers expected to offset 2017 expected cost increases?

A. No. If margin revenue increased by 1%, which is a reasonable expectation, the increase in margin revenue would be approximately $300,000. A typical wage increase of 3% would offset half that amount while a simple inflation calculation would offset the remaining half. For this reason the selection of a 2016 test year yields conservative results.

Q. What is your total revenue requirement?

A. Our total revenue requirement is $84,871,728, which includes a proposed increase of $1,906,285 for a rate of return of 7.31%. The Company's calculation of its revenue requirement is found in Exhibit CNG/202.

Q. Please explain the conversion factor found on line 6 of Exhibit CNG/202.

A. Exhibit CNG/203 shows the calculation of the conversion factor which is applied to the required net income to produce the required revenue increase. The conversion factor takes into account revenue-sensitive items that change as revenue changes, including uncollectibles, franchise taxes, Commission fees, Oregon state income tax, and federal income taxes. The conversion factor is 0.58471.

Q. Please explain the adjusted revenues on line 8 of Exhibit CNG/202.

A. Exhibit CNG/204 shows each of the Company's proposed adjustments culminating in a total column, column (p). The total column is also shown in Exhibit CNG/201, column (2).

Q. Would you describe each of the adjustments included in Exhibit CNG/204?

A. Yes. The first column, column (a), entitled “Uncollectibles Expense” is an adjustment to test period booked uncollectibles expense to the average of the last three years of actual bad debt write-offs. This adjustment is consistent with the Type I adjustment in Cascade’s annual earnings report. The result is a decrease in net income of $116,779.

Column (b), entitled “Removal 25% Membership Fees” adjusts 25% 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 $2,456.

Column (c), entitled “Promotional Advertising Adjustment” removes all base year advertising. The Commission’s administrative rules establish ratemaking categories for various types of utility advertising expenses.[2] Cascade removed all promotional advertising expense booked to FERC account 913 along with all Category C advertising. The result is an increase in net income of $11,713.

Column (d), entitled “Interest Coordination Adjustment” adjusts federal income tax for the effect of the average debt rate used to calculate the rate of return applied to the proposed rate base shown in Exhibit CNG/201, 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 $143,495.

Column (e), entitled “PGA Commodity Sharing Adj.” adjusts gas costs to reflect the amount of Purchase Gas Adjustment (PGA) commodity sharing

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

that was accrued or booked during the base year. Cascade is decreasing earnings to remove the sharing benefit received by the Company by $433,904 during 2015 as a result of commodity costs being less than those built into the PGA. The result of this adjustment is a decrease in net operating income of $260,603.

Column (f), entitled “Annualizing Wage Rate Adjustment” reflects the full year impact of the union contract wage increase that was effective April 1, 2015. This adjustment reduces net income by $15,025.

Column (g), entitled “2016 Revenue Adjustment’ adds margin revenue to account for the additional customers at weather normalized loads to be added during 2016. This adjustment also reflects final rates authorized in docket UG 287 on projected loads. This adjustment increases net income by $840,405.

Column (h), entitled “2016 Wage Adjustment” reflects the actual wage adjustment applied to non-union and union employees. Non-union wage increases were effective January 1, 2016, and union increases were effective April 1, 2016. The non-union increase granted was 4% and the union increase on April 1, 2016, increase was 3.1%. This adjustment decreases net income by $116,438.

Column (i), entitled “AC Survey Adjustment” reflects a change in the company’s Atmospheric Corrosion (AC) Survey program. Cascade was using contractors to perform AC Survey work but has moved the program in-house as a result our most recent union contract negotiations. This change will provide more control of the work, and better tracking of information. This adjustment decreases net income by $7,478.

Column (j), entitled "Public Purpose Cost Reallocation" removes from expenses the portion of costs provided to the Energy Trust of Oregon (ETO) as part of the Company's general expenses. During 2015, additional funds were provided to the ETO in an amount not less than $500,000 per year consistent with the Commission's order in docket UG 167.[3] The recovery mechanism changed as a result of docket UG 287 to collect all ETO funds in the Public Purpose Charge (PPC). The booked expense therefore needs to be removed. This adjustment increases net income by $304,297.

Column (k), entitled "2016 Plant Additions" provides the Company's budgeted level of capital additions expected to go into service during 2016. The majority of the projected investments are non-revenue producing. The Company will update this projection later in the case to reflect actual costs and more up-to-date estimates. The net income effect of the rate base additions, for depreciation expense and property taxes, is a decrease of $425,543. The rate base impact is an increase of $7,238,320.

Column (l), entitled "Inflation Factor Adj" shows the impact of applying a consumer price index (CPI) inflation factor to non-labor related expenses. The net income effect is a decrease of $54,191.

Column (m), entitled "Resource Planning Adjustment" reflects additions to labor expenses for employees that will be added in 2016. The Company is anticipating a net gain of two additional positions in 2016 on a system basis. These two positions are added in response to the Commission's recommendation in Order No. 16-054 issued in docket LC 59 that the

[3] *In the Matter of Cascade Natural Gas Corporation Request for Authorization to Establish a Decoupling Mechanism and Approval of Tariff Sheets No. 30 and No. 30-A*, Docket UG 167, Order No. 06-191 at 3 (Apr. 19, 2006).

Company increase staffing to ensure Integrated Resource Plan (IRP) activities are filed both in compliance with requirements and in a timely manner. The net effect of this adjustment is a decrease on net income of $30,467.

Column (n), entitled "Depreciation Expense Adj" shows the impact of the depreciation rates for 2016. The resolution of docket UM 1727 resulted in new depreciation rates effective January 1, 2016. The impact of applying the authorized depreciation rates to actual plant as of December 31, 2015, is an increase to depreciation expense of $390,322. This results in a decrease to net income of $234,427.

Column (o), entitled "A&G Adjustment" provides removal of miscellaneous general expenses not appropriate for recovery through customer rates. Cascade performed an analysis of Standard Data Request 57 to determine booked expenses inappropriate for rate recovery. This adjustment increase net income by $12,122.

IV. CAPITAL STRUCTURE AND RATE OF RETURN

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

A. The Company is requesting a rate of return of 7.31% with a capital structure of 49% equity and 51% 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	49%	9.40%	4.61%
Total Debt	51%	5.295%	2.70%
	100%		7.31%

Q. Why does the Company believe a capital structure of 49% equity and 51% debt is appropriate?

A. The requested capital structure is based upon Cascade's actual capital structure for the last three 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. Cascade believes this capital structure is reasonable. Table 2 provides a summary of the three year history of Cascade's capital structure.

Table 2. Capital Structure			
	12/31/2013	12/31/2014	12/31/2015
Total Debt	51.7%	49.3%	52.9%
Common Equity	48.3%	50.7%	47.3%

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

A. The Company is relying on a recent Commission decision.[4]

V. 2016 PLANT ADDITIONS

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

A. Yes. Cascade's 2016 plant additions account for $1,637,404 of the total revenue requirement increase of $1,906,285.

Q. What plant additions are planned for 2016?

A. Attached as Exhibit CNG/205 is a list of all the projects planned for 2016. This list includes a brief project description and an estimated cost. These projected costs and projects will be updated as actual costs and in-service dates become known.

VI. BASIC CHARGE RECOMMENDATION

Q. Please explain why Cascade is proposing to hold basic charges constant for rate schedules 101 and 104?

A. Cascade believes in promoting the direct use of natural gas for heating homes and water. We realize that residential and commercial customers who choose to use natural gas will also be electricity customers, and for that reason, will have two energy bills to pay each month regardless of usage. Cascade is proposing to continue charging a low basic charge and volumetric heavy rate design to alleviate that impact on customers.

Q. Why is it appropriate for the Company's rate structure to support the direct use of natural gas?

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[4] *See Public Utility Commission of Oregon v. Avista Corp.,* Docket No. UG-288, Order No. 16-076.

A. There are two primary reasons; first, direct use of natural gas is much more efficient than using natural gas to produce electricity. Secondly, decreasing usage is the most efficient form of conservation an electric utility could invest in.

VII. ALLOWED MARGIN FOR DECOUPLING MECHANISM

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

A. Yes, Exhibit CNG/206.

Q. Please describe Exhibit CNG/308 and how it will be used after the conclusion of this docket?

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

Q. Does this conclude your testimony?

A. Yes it does.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

MICHAEL P. PARVINEN
Exhibit No. 201

Results of Operation Summary Sheet

Cascade Natural Gas
Results of Operation Summary Sheet
Twelve Months Ended December 31, 2015

SUMMARY SHEET	2015 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	63,397,033	1,437,260	64,834,293	1,906,285	66,740,578
2 Gas Transportation Revenue	3,992,733	0	3,992,733		3,992,733
3 Other Operating Revenues	260,460	0	260,460		260,460
4 SUBTOTAL	67,650,226	1,437,260	69,087,486	1,906,285	70,993,771
5 LESS: Nat. Gas/Production Costs	36,535,517	433,904	36,969,421		36,969,421
6 Revenue Taxes	2,877,481	30,326	2,907,807	40,223	2,948,029
7 **OPERATING MARGIN**	28,237,228	973,030	29,210,258	1,866,062	31,076,321
Operating Expenses					
8 Production	108,233	1,299	109,532		109,532
9 Distribution	5,639,690	97,202	5,736,892		5,736,892
10 Customer Accounts	1,709,474	222,609	1,932,083	10,158	1,942,241
11 Customer Service	612,804	(506,656)	106,148		106,148
12 Sales	2,313	(19,501)	(17,189)		(17,189)
13 Administrative and General	5,451,075	619,327	6,070,401		6,070,401
14 Depreciation & Amortization	6,111,512	507,672	6,619,184		6,619,184
15 Regulatory Debits		0	0		0
16 Taxes Other Than Income	1,926,429	200,857	2,127,286		2,127,286
17 State & Federal Income Taxes	1,356,152	83,673	1,439,825	741,248	2,181,073
18 **Total Operating Expenses**	22,917,681	1,206,482	24,124,163	751,406	24,875,569
19 **Net Operating Revenues**	5,319,548	(233,453)	5,086,095	1,114,656	6,200,751
Rate Base					
20 Total Plant in Service	193,751,247	13,673,972	207,425,219		207,425,219
21 Total Accumulated Depreciation	(91,373,668)	(6,365,348)	(97,739,016)		(97,739,016)
22 Contributions in Aid of Construction	0	0	0		0
23 Customer Adv. For Construction	(495,562)	0	(495,562)		(495,562)
24 Deferred Accumulated Income Taxes	(26,536,580)	(70,305)	(26,606,885)		(26,606,885)
25 Deferred Debits		0	0		0
26 Working Capital Allowance	2,287,971	0	2,287,971		2,287,971
27 **TOTAL RATE BASE**	77,633,408	7,238,320	84,871,728	0	84,871,728
28 **Rate of Return**	6.85%		5.99%		7.31%

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

MICHAEL P. PARVINEN
Exhibit No. 202

Revenue Requirement Calculation

Cascade Natural Gas
Revenue Requirement Calculation
UG 305

1	Adjusted Rate Base	$84,871,728
2	Rate of Return	7.31%
3	Required Return (ln 1 x ln 2)	$6,200,728
4	Adjusted Net Income	$5,086,095
5	Required Net Income Increase (ln 3 - ln 4)	$1,114,633
6	Conversion Factor	0.58471
7	Revenue Increase Required (ln 5 / ln 6)	**$1,906,285**
8	Test Year Adjusted Revenue	$69,087,486
9	Overal Revenue Increase	**2.7592%**

BEFORE THE

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DOCKET NO. UG 305

MICHAEL P. PARVINEN
Exhibit No. 203

Conversion Factor Calculation

Cascade Natural Gas Conversion Factor Calculation Twelve Months Ended December 31, 2015 REVENUE SENSITIVE COSTS UG 305	
Revenues	1.00000
Operating Revenue Deductions	
Uncollectible Accounts	0.00533
Taxes Other - Franchise	0.01835
OPUC Fees	0.00275
Interest expense	
State Taxable Income	0.97357
State Income Tax	0.07401
Federal Taxable Income	0.89956
Federal Income Tax @ 35%	0.31485
Total Income Taxes	0.38886
Total Revenue Sensitive Costs	0.41529
Net-to-Gross Factor	**0.58471**
Combo-State & Federal Income Tax	
State	0.07600
Federal	0.35000
State and Federal Effective Tax Rate	0.3994

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MICHAEL P. PARVINEN
Exhibit No. 204

Proposed Adjustments to Base Year Results

Cascade Natural Gas
Proposed Adjustments to Base Year Results
UG 305

		Uncollectibles Expense (a)	Removal 25% Membership Fees (b)	Promotional Advertising Adjustment (c)	Interest Coordination Adjustment (d)	PGA Commodity Sharing Adj. (e)	Annualizing Wage Rate Adjustment (f)	2016 Revenue Adjustment (g)	2016 Wage Adjustments (h)	AC Survey Adjustment (i)	Public Purpose Cost Reallocation (j)	2016 Plant Additions (k)	Inflation Factor Adj (l)	Resource Planning Adjustment (m)	Depreciation Expense Adj (n)	A&G Adjustment (o)	**Total Adjustments (Base Rates) (p)**
1	**Operating Revenues**																
2	Natural Gas Sales							$1,437,260					$0	$0	$0	$0	1,437,260
3	Gas Transportation Revenue												0	0	0	0	0
4	Other Operating Revenues												0	0	0	0	0
5	SUBTOTAL	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,437,260**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$1,437,260**
6	LESS: Nat. Gas/Production Costs					433,904											$433,904
7	Revenue Taxes					0		30,326									$30,326
8	**OPERATING MARGIN**	**$0**	**$0**	**$0**	**$0**	**($433,904)**	**$0**	**$1,406,934**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**	$973,030
9																	$0
10	**Operating Expenses**																$0
11	Production												1,299				$1,299
12	Distribution									12,450			34,024	50,728			$97,202
13	Customer Accounts	$194,437				$0		$7,658					20,514				$222,609
14	Customer Service										(506,656)		0				($506,656)
15	Sales			(19,501)													($19,501)
16	Administrative and General		(4,090)				25,017		193,869				34,392		390,322	(20,183)	$619,327
17	Depreciation & Amortization											507,672			0		$507,672
18	Regulatory Debits																$0
19	Taxes Other Than Income											200,857					$200,857
20	State & Federal Income Taxes	(77,658)	1,634	7,789	143,495	(173,301)	(9,992)	558,871	(77,431)	(4,973)	202,358	(282,987)	(36,037)	(20,261)	(155,894)	8,061	$83,673
21	**Total Operating Expenses**	116,779	(2,456)	(11,713)	143,495	(173,301)	15,025	566,529	116,438	7,478	(304,297)	425,543	54,191	30,467	234,427	(12,122)	$1,206,482
22	**Net Operating Revenues**	($116,779)	$2,456	$11,713	($143,495)	($260,603)	($15,025)	$840,405	($116,438)	($7,478)	$304,297	($425,543)	($54,191)	($30,467)	($234,427)	$12,122	($233,453)
24	**Rate Base**																
25	Total Plant in Service											13,673,972					$13,673,972
26	Total Accumulated Depreciation											(6,365,348)					($6,365,348)
27	Contributions in Aid of Construction																$0
28	Customer Adv. For Construction																$0
29	Deferred Accumulated Income Taxes											(70,305)					($70,305)
30	Deferred Debits																$0
31	Working Capital Allowance																$0
32	**TOTAL RATE BASE**	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$7,238,320	$0	$0	$0	$0	$7,238,320
33																	
34	**Revenue Requirement Effect**	**$199,720**	**($4,201)**	**($20,031)**	**$245,410**	**$445,692**	**$25,696**	**($1,437,290)**	**$199,136**	**$12,789**	**($520,420)**	**$1,632,204**	**$92,679**	**$52,106**	**$400,925**	**($20,731)**	**$1,303,685**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

MICHAEL P. PARVINEN
Exhibit No. 205

2016 Plant Additions

Cascade Natural Gas
2016 Plant Additions
UG 305

Work Order and Description	Account	State	Investment		Investment
FP-101209 - INTANGIBLES - SOFTWARE	3030-Misc. Intangible Plant	AS	59,284.50	0.2427	14,388.35
FP-101472 - UG-INSTALL WORK MGT-GLE	3030-Misc. Intangible Plant	AS	330,236.54	0.2427	80,148.41
FP-101479 - UG MWM PROJECT - CNGC SHARE	3030-Misc. Intangible Plant	AS	43,116.00	0.2427	10,464.25
FP-101481 - UG GPSLS PROJECT - SOFTWARE	3030-Misc. Intangible Plant	AS	74,079.42	0.2427	17,979.08
FP-200064 - IVR-WEB IMPLEMENTATIION - DRCT	3030-Misc. Intangible Plant	AS	263,370.51	0.2427	63,920.02
FP-200663 - UG GIS ENHANCEMENTS CNG DIRECT	3030-Misc. Intangible Plant	AS	692,499.89	0.2427	168,069.72
FP-301808 - UG-Routing Software - Survey System	3030-Misc. Intangible Plant	AS	21,612.90	0.2427	5,245.45
FP-301813 - WR-GAS SCADA Enhancements	3030-Misc. Intangible Plant	AS	211,247.17	0.2427	51,269.69
FP-302571 - CC&B Upgrade	3030-Misc. Intangible Plant	AS	1,341,477.29	0.2427	325,576.54
FP-302579 - PII - Personal Info Security	3030-Misc. Intangible Plant	AS	32,983.80	0.2427	8,005.17
FP-302613 - PowerPlan Upgrade	3030-Misc. Intangible Plant	AS	208,501.67	0.2427	50,603.36
FP-302616 - Human Capital Management	3030-Misc. Intangible Plant	AS	57,122.21	0.2427	13,863.56
FP-302619 - JDE Upgrade	3030-Misc. Intangible Plant	AS	308,237.74	0.2427	74,809.30
FP-311939 - PCAD UPGRADE TO 6.5	3030-Misc. Intangible Plant	AS	236,535.11	0.2427	57,407.07
FP-200076 - MN - HANFORD DOE PRELIMINARY	3671-Transmission Mains	WA	17,608.00		
FP-309960 - RP 20" HP Anacortes Lateral	3671-Transmission Mains	WA	(302,000.00)		
FP-302062 - Mains - GO	3760-Mains	AS	(3,000,000.29)	0.2427	(728,100.07)
FP-306995 - OTHELLO REYNOLDS RD REINFORCEMENT	3760-Mains	WA	362,486.04		
FP-302369 - GB - GROUNDBED WASHINGTON	3761-CNG Mains Steel	WA	280,024.00		
FP-302370 - GB - GROUNDBED OREGON	3761-CNG Mains Steel	OR	140,012.00		140,012.00
FP-302665 - RICHLAND 4" IP CANAL/HWY CROSSING	3761-CNG Mains Steel	WA	435,043.61		
FP-306985 - SEDRO WOOLLEY IP REINFORCEMENT	3761-CNG Mains Steel	WA	105,518.21		
FP-307025 - CRM SHELTON 4" IP BRIDGE REPLACE	3761-CNG Mains Steel	WA	9,163.63		
FP-309000 - 4 in Steel IP Bore Columbia Park	3761-CNG Mains Steel	WA	147,983.11		
FP-309001 - 2 IN STEEL IP BORE BELFAIR PL	3761-CNG Mains Steel	WA	155,862.36		
FP-311354 - DEEP WELL GB - YAKIMA	3761-CNG Mains Steel	WA	91,480.64		
FP-311356 - DEEP WELL GB - KENNEWICK	3761-CNG Mains Steel	WA	91,480.64		
FP-311357 - DEEP WELL GB - ANACORTES	3761-CNG Mains Steel	WA	91,480.64		
FP-311358 - DEEP WELL GB - WALLA WALLA	3761-CNG Mains Steel	WA	91,480.64		
FP-312041 - CRM 6" Nob Hill Replacement	3761-CNG Mains Steel	WA	62,069.48		
FP-312043 - Kennewick RR Cross Near Kamiakin	3761-CNG Mains Steel	WA	123,821.09		
FP-312045 - V-7 MT VERNON	3761-CNG Mains Steel	WA	80,277.70		
FP-101170 - MAIN-GROWTH-OREGON	3762-CNG Mains High Press Steel	OR	498,617.72		498,617.72
FP-101171 - MAIN-REINFORCE-OREGON	3762-CNG Mains High Press Steel	OR	51,515.38		51,515.38
FP-101172 - MAIN-RELO-REPL-OREGON	3762-CNG Mains High Press Steel	OR	103,030.25		103,030.25
FP-101190 - MAIN-GROWTH-WASHINGTON	3762-CNG Mains High Press Steel	WA	997,235.45		
FP-101192 - MAIN-RELO-REPL-WASHINGTON	3762-CNG Mains High Press Steel	WA	309,090.84		
FP-200080 - RF; 12" STEEL HP SHELTON	3762-CNG Mains High Press Steel	WA	7,909,471.00		
FP-200394 - CRM RPL 10" SQUALICUM CRK EXPOSURE	3762-CNG Mains High Press Steel	WA	60,350.00		
FP-200419 - RF - KITSAP 12" HP REINFORCE	3762-CNG Mains High Press Steel	WA	32,934.38		
FP-200689 - RPL 12" BEND HP LINE #1	3762-CNG Mains High Press Steel	OR	63,641.86		63,641.86

Cascade Natural Gas
2016 Plant Additions
UG 305

Work Order and Description	Account	State	Investment	Investment
FP-200691 - CRM REL ZILLAH @ MEYERS BRIDGE RD	3762-CNG Mains High Press Steel	WA	774.91	
FP-300346 - CRM RPL; 12" STEEL HP, KELSO	3762-CNG Mains High Press Steel	WA	62,069.48	
FP-302588 - HILDEBRAND BLVD 6" HP MAIN	3762-CNG Mains High Press Steel	WA	240,728.24	
FP-302596 - CRM 8" ATTALIA HP LINE REPLACEMENT	3762-CNG Mains High Press Steel	WA	62,069.48	
FP-302640 - 6" PILOT ROCK HP REPLACEMENT	3762-CNG Mains High Press Steel	OR	62,069.48	62,069.48
FP-302666 - MT. WASHINGTON BRIDGE CROSSING	3762-CNG Mains High Press Steel	OR	465,521.53	465,521.53
FP-302714 - PENDLETON V-23 REPLACEMENT	3762-CNG Mains High Press Steel	OR	230,536.03	230,536.03
FP-302715 - 16" N. WHATCOM VALVE VAULT	3762-CNG Mains High Press Steel	WA	3,576.73	
FP-306982 - CRM VANCE CREEK EXPOSURE REPLACE	3762-CNG Mains High Press Steel	WA	1,180,050.98	
FP-306983 - CRM CAMP CREEK EXPOSURE REPLACEMENT	3762-CNG Mains High Press Steel	WA	1,173,949.20	
FP-306986 - CRM 3" BURLINGTON HP LINE REPL	3762-CNG Mains High Press Steel	WA	1,118,159.30	
FP-306997 - 4" MADRAS HP LINE REPLACEMENT	3762-CNG Mains High Press Steel	OR	62,069.48	62,069.48
FP-307002 - V-9 ABERDEEN REPLACEMENT	3762-CNG Mains High Press Steel	WA	204,829.57	
FP-307221 - 8" YAKIMA HP PIPELINE	3762-CNG Mains High Press Steel	WA	62,069.48	
FP-200059 - RF 6" PE MN @ YAKIMA AIRPORT	3763-CNG Mains Plastic	WA	79.62	
FP-200686 - CRM RPL LONGVIEW BARE STEEL	3763-CNG Mains Plastic	WA	4,493,698.80	
FP-200687 - CRM RPL ANACORTES BARE STEEL	3763-CNG Mains Plastic	WA	2,945,079.99	
FP-200688 - BEND PIPE REPL	3763-CNG Mains Plastic	OR	4,637,699.96	4,637,699.96
FP-300363 - CRM RPL SHELTON BARE STEEL	3763-CNG Mains Plastic	WA	53.65	
FP-302641 - 4" PILOT ROCK IP REINFORCEMENT	3763-CNG Mains Plastic	OR	62,069.48	62,069.48
FP-303142 - PENDLETON BARE STEEL REPLACEMENT	3763-CNG Mains Plastic	OR	62,069.48	62,069.48
FP-307225 - RIVER ROAD REINFORCEMENT	3763-CNG Mains Plastic	WA	920,106.06	
FP-312040 - Poulsbo 4" PE Reinforcement	3763-CNG Mains Plastic	WA	309,552.61	
FP-312221 - MN 4" PE SHELTON	3763-CNG Mains Plastic	WA	4,470.24	
FP-101173 - R STA-GROWTH-OREGON	3780-Meas & Reg Equip Gen	OR	66,409.14	66,409.14
FP-101175 - R STA-RELO-REPL-OREGON	3780-Meas & Reg Equip Gen	OR	124,960.68	124,960.68
FP-101194 - R STA-GROWTH-WASHINGTON	3780-Meas & Reg Equip Gen	WA	265,636.56	
FP-101196 - R STA-RELO-REPL-WASHINGTON	3780-Meas & Reg Equip Gen	WA	493,122.24	
FP-200122 - RP; R-58, ABERDEEN	3780-Meas & Reg Equip Gen	WA	213,930.35	
FP-200282 - R STA - SUN RIVER GATE UPGRADE	3780-Meas & Reg Equip Gen	OR	1,609,608.08	1,609,608.08
FP-302650 - O-4 UMATILLA	3780-Meas & Reg Equip Gen	OR	95,686.16	95,686.16
FP-302651 - O-6 ATHENA	3780-Meas & Reg Equip Gen	OR	209,852.11	209,852.11
FP-302672 - BREMERTON R-146 RELOCATE	3780-Meas & Reg Equip Gen	WA	578,487.99	
FP-302713 - CHICO CHECK METER	3780-Meas & Reg Equip Gen	WA	62,069.48	
FP-302724 - MCCLEARY GATE UPGRADE	3780-Meas & Reg Equip Gen	WA	23,119.39	
FP-311997 - 0-1 Ontario	3780-Meas & Reg Equip Gen	OR	153,985.41	153,985.41
FP-311998 - 0-3 Stanwood	3780-Meas & Reg Equip Gen	WA	309,552.62	
FP-311999 - 0-1 Mission	3780-Meas & Reg Equip Gen	OR	152,809.12	152,809.12
FP-312000 - 0-2 Terrace Heights	3780-Meas & Reg Equip Gen	WA	123,504.18	
FP-312003 - R-53 Shelton	3780-Meas & Reg Equip Gen	WA	55,862.72	
FP-312004 - R-2 Aberdeen	3780-Meas & Reg Equip Gen	WA	92,865.88	

Cascade Natural Gas 2016 Plant Additions UG 305					
Work Order and Description	Account	State	Investment		Investment
FP-312005 - R-29 Nooksack	3780-Meas & Reg Equip Gen	WA	80,277.70		
FP-312006 - R-31 Kennewick	3780-Meas & Reg Equip Gen	WA	66,521.71		
FP-312013 - R-9 Weston	3780-Meas & Reg Equip Gen	OR	103,910.19		103,910.19
FP-312015 - R-4 Hermiston	3780-Meas & Reg Equip Gen	OR	103,910.19		103,910.19
FP-312037 - R-22 Toppenish	3780-Meas & Reg Equip Gen	WA	103,118.40		
FP-312038 - R-29 Toppenish	3780-Meas & Reg Equip Gen	WA	103,118.40		
FP-101176 - SERV-GROWTH-OREGON	3803-CNG Services Plastic	OR	1,818,539.98		1,818,539.98
FP-101197 - SERV-GROWTH-WASHINGTON	3803-CNG Services Plastic	WA	4,243,260.06		
FP-101210 - PRE-CAP MTR-GROWTH-INTERSTAT	3810-Gas Meters	AS	4,467,804.92	0.2427	1,084,336.25
FP-101259 - PRE-CAP REG-GROWTH-INTERSTAT	3830-Service Regulators	AS	508,638.39	0.2427	123,446.54
FP-101180 - IND M&R-GROWTH-OREGON	3850-Ind. Meas. & Reg. Statio	OR	176,262.98		176,262.98
FP-101181 - IND M&R-REMOVE&REPLACE-OREGON	3850-Ind. Meas. & Reg. Statio	OR	50,701.20		50,701.20
FP-101200 - IND M&R-GROWTH-WASHINGTON	3850-Ind. Meas. & Reg. Statio	WA	671,502.39		
FP-101201 - IND M&R-REMOVE&REPL-WASHINGTON	3850-Ind. Meas. & Reg. Statio	WA	123,280.80		
FP-312042 - M&R REBUILD, BOISE CASCADE	3850-Ind. Meas. & Reg. Statio	WA	123,504.18		
FP-101213 - GP BUILDINGS - INTERSTATE	3901-CNG Structures & Improvement	AS	32,337.00	0.2427	7,848.19
FP-101395 - GP BUILDINGS - TRI - CITIES	3901-CNG Structures & Improvement	WA	32,337.00		
FP-307044 - Aberdeen New Operations Building 20	3901-CNG Structures & Improvement	WA	10,044.51		
FP-200661 - DATA CENTER/NETWORKING EQUIP	3913-CNG Servers and Workstation	AS	150,690.48	0.2427	36,572.58
FP-200662 - PC SUPPORT EQUIPMENT	3913-CNG Servers and Workstation	AS	296,745.87	0.2427	72,020.22
FP-306967 - District Office Access Control Sys	3913-CNG Servers and Workstation	AS	78,359.32	0.2427	19,017.81
FP-101360 - GP OFFICE EQUIP - ABERDEEN	3915-CNG Office Furniture & Fixt	WA	10,347.84		
FP-101396 - GP OFFICE EQUIP - TRI - CITIES	3915-CNG Office Furniture & Fixt	WA	2,694.75		
FP-101184 - GP TRAN. VEHICLE - OREGON	3922-Transportation Equipmen	OR	389,751.64		389,751.64
FP-101204 - GP TRAN. VEHICLE - WASHINGTO	3922-Transportation Equipmen	WA	1,659,242.52		
FP-101215 - GP TRAN. VEHICLE - INTERSTAT	3922-Transportation Equipmen	AS	409,686.96	0.2427	99,431.03
FP-101216 - GP TOOLS - INTERSTATE	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	AS	133,228.44	0.2427	32,334.54
FP-101218 - GP TOOLS - BEND	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	OR	62,949.36		62,949.36
FP-101237 - GP TOOLS - PENDLETON	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	OR	25,652.94		25,652.94
FP-101255 - GP TOOLS - ONTARIO	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	OR	13,161.16		13,161.16
FP-101288 - GP TOOLS - BELLINGHAM	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	WA	19,509.99		
FP-101307 - GP TOOLS - MT VERNON	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	WA	45,271.80		
FP-101326 - GP TOOLS - BREMERTON	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	WA	67,260.96		
FP-101344 - GP TOOLS - LONGVIEW	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	WA	33,738.27		
FP-101362 - GP TOOLS - ABERDEEN	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	WA	15,952.92		
FP-101398 - GP TOOLS - TRI - CITIES	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	WA	44,409.48		
FP-101451 - GP TOOLS - YAKIMA	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	WA	66,829.80		
FP-311969 - Sensit Gold G-2 Detectors	3941-MDU/GPNG/CNG Tools, Shop & Garage Eq	AS	296,422.50	0.2427	71,941.74
FP-101163 - GP POWER EQUIP - INTERSTATE	3962-Power Operated Equipmen	AS	64,674.00	0.2427	15,696.38
FP-101186 - GP POWER EQUIP - OREGON	3962-Power Operated Equipmen	OR	234,749.12		234,749.12
FP-101206 - GP POWER EQUIP - WASHINGTON	3962-Power Operated Equipmen	WA	573,461.00		
FP-101164 - GP COMM EQUIP - INTERSTATE	3972-CNG Comm Equip Telemeterin	AS	271,630.80	0.2427	65,924.80
			53,670,290.94		**13,673,972.08**

CNGC/206
Parvinen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

MICHAEL P. PARVINEN
Exhibit No. 206

Decoupling Allowed Margin Per Customer

Post-CAP filing

R/S 101	0.40656
R/S 104	0.26263

Cascade Natural Gas Corporation

Calculation of Baseline Monthly Commodity Margin Per Customer
Based upon Weather Normalized Therm Sales
As Reflected In The 2013 Purchased Gas Adjustment Application
State Of Oregon

	Adjusted Therms	Actual Customers	Commodity Margin	Baseline Avg Commodity Margin/cust
Residential Rate Schedule 101				
Jan-16	6,311,493	59,456	$ 2,566,000.73	$ 43.16
Feb-16	5,375,172	59,550	$ 2,185,330.06	$ 36.70
Mar-16	4,270,165	59,575	$ 1,736,078.26	$ 29.14
Apr-16	3,173,017	59,600	$ 1,290,021.83	$ 21.64
May-16	2,070,444	59,610	$ 841,759.66	$ 14.12
Jun-16	1,213,215	59,473	$ 493,244.51	$ 8.29
Jul-16	893,538	59,457	$ 363,276.67	$ 6.11
Aug-16	900,839	59,513	$ 366,245.26	$ 6.15
Sep-16	1,271,233	59,754	$ 516,832.30	$ 8.65
Oct-16	2,740,634	60,159	$ 1,114,232.25	$ 18.52
Nov-16	4,883,478	60,608	$ 1,985,426.83	$ 32.76
Dec-16	6,866,281	60,784	$ 2,791,555.20	$ 45.93
Total	39,969,509	717,540	$ 16,250,003.58	**$ 271.17**
Average		59,795		
Commercial Rate Schedule 104				
Jan-16	4,344,371	9,852	$ 1,140,962.03	$ 115.81
Feb-16	3,648,644	9,855	$ 958,243.25	$ 97.23
Mar-16	2,877,999	9,831	$ 755,848.78	$ 76.88
Apr-16	2,155,734	9,811	$ 566,160.49	$ 57.71
May-16	1,501,462	9,806	$ 394,328.84	$ 40.21
Jun-16	1,015,797	9,775	$ 266,778.79	$ 27.29
Jul-16	864,643	9,757	$ 227,081.17	$ 23.27
Aug-16	866,686	9,747	$ 227,617.84	$ 23.35
Sep-16	1,042,919	9,771	$ 273,901.95	$ 28.03
Oct-16	1,896,418	9,801	$ 498,056.14	$ 50.82
Nov-16	3,273,100	9,891	$ 859,614.25	$ 86.91
Dec-16	4,630,068	9,931	$ 1,215,994.80	$ 122.45
Total	28,117,840	117,828	$ 7,384,588.32	**$ 749.97**
Average		9,819		

CNGC/300
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

DIRECT TESTIMONY OF RONALD J. AMEN
REPRESENTING CASCADE NATURAL GAS CORPORATION

LONG-RUN INCREMENTAL COST STUDY / RATE DESIGN

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

Contents

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

I. INTRODUCTION AND SUMMARY

Q. Please state your name and business address.

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

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

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

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

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

Q. Please describe the firm of Black & Veatch.

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

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

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

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

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

A. I have over 37 years of experience in the utility industry, the last 18 years of which have been in the field of utility management and economic consulting. Specializing in the natural gas industry, I have advised and assisted utility management, industry trade organizations, and large energy users in matters pertaining to costing and pricing, competitive market analysis, regulatory planning and policy development, resource planning issues, strategic business planning, merger and acquisition analysis, organizational restructuring, new product and service development, and load research studies. I have prepared and presented expert testimony before utility regulatory bodies and have spoken on utility industry issues and activities dealing with the pricing and marketing of gas utility services, gas and electric resource planning and evaluation, and utility infrastructure replacement. Further background information summarizing my work experience, presentation of expert testimony, and other industry-related activities is included in Exhibit CNG/309.

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

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

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

Q. Please summarize your testimony.

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

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

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

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

A. The following exhibits accompany my testimony.

- Exhibit CNG/301 Summary of LRIC
- Exhibit CNG/302 Functional Revenue Requirement
- Exhibit CNG/303 Incremental Plant Carrying Costs
- Exhibit CNG/304 Incremental O&M Costs
- Exhibit CNG/305 Summary of Revenue by Rate Class
- Exhibit CNG/306 Analysis of Revenue by Detailed Rate Schedule
- Exhibit CNG/307 Residential Impact by Month
- Exhibit CNG/308 Impact of Recommended Rate Changes
- Exhibit CNG/309 Ronald J. Amen Statement of Qualifications

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

II. THEORETICAL PRINCIPLES OF COST ALLOCATION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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III. CASCADE'S LRIC STUDY

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

A. Yes. Exhibit CNG/301 presents Cascade's LRIC Study. In particular, the exhibit presents the resulting allocation by rate schedule of Cascade's proposed revenue requirement based strictly on the results of the LRIC computations included in the LRIC Study.

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

A. Cascade has chosen to follow a similar methodology as that employed previously by the Company in Docket UG 287 and by Avista Utilities in Docket UG 246. The primary elements of Cascade's LRIC Study are incremental plant investments and incremental operations and maintenance expenses (O&M). The incremental cost information related to these elements are accumulated on a cost per customer basis for each of Cascade's tariff rate schedules summarized to represent the long-run incremental cost for customers on Cascade's distribution system.

A. Incremental Plant Investment Costs

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

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

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

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

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

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

A. The first component of Cascade's distribution mains analysis derives the customer related costs associated with the installation of distribution mains to connect new customers. Mains investments that serve this function were extracted from Cascade's plant accounting records. Oregon new business project work orders were summarized for a fourteen-year period (2002 – 2015). The customer cost was computed by taking the average cost per foot of Cascade's minimum-sized distribution main (two-inch), escalated to current dollars (2015) using the Handy Whitman Index of Public Utility Construction Costs, and multiplying that unit cost by the number of feet of main installed per new customer for Residential (Schedule No. 101), Commercial (Schedule No. 104), and Industrial (Schedule No. 105) service classes. For the larger core classes (Schedule No. 111 and Schedule No. 170) and the non-core class (Schedule No. 163), as well as the Special Contract Class (Schedule No. 900), the distribution main segments connected to the individual customers were identified using Cascade's Geographic Information System (GIS). The in-service date of the main segment, its size, type and length were compiled and current costs (2015 dollars) applied to compute the corresponding installed costs. For smaller core classes (Schedule Nos. 101 and 104), a regression analysis was performed on a sample of recent work order main extensions to determine the typical feet of mains per customer. For Schedule No. 105, twenty-one main extension work orders were used as a representative sample.

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Q. How were the incremental costs of distribution mains determined for system capacity reinforcement, and safety and reliability investments?

A. Incremental mains investments that serve these two functions were extracted from Oregon project work orders and were summarized for a seven-year historic period (2009 – 2015) and a five-year budget forecast (2016-2020). The reinforcement projects are considered capacity-related and allocated to Cascade's core classes on the basis of their contribution to the system peak day. Targeted reinforcement projects attributable to the Special Contract class for the five-year budget period were directly assigned to this class.

The safety and reliability projects are considered commodity-related and were therefore allocated to all classes except for the Special Contract class on the basis of annual throughput.

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

A. Long-term distribution mains replacement costs were estimated by calculating the current cost of Oregon mains in service at December 2015. Current costs of the prior three categories of distribution mains, new customer main extensions, reinforcement, and safety and reliability investments, were deducted to determine the remaining level of system replacement investment. This remaining investment was separated into capacity versus commodity components using Cascade's Oregon system load factor and then allocated to the appropriate classes using design day demand and annual throughput, respectively.

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

A. Once the investment costs for all mains were derived, the incremental costs were computed by applying an Economic Carrying Charge Rate (ECCR) to the investment costs. The derivation of the LRIC for distribution mains is presented in Exhibit CNG/303, Plant Carrying Costs.

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

A. Cascade's LRIC Study derives the incremental costs of installing new services using Cascade's recent actual installation costs from 2009 to 2015 escalated to 2015 dollars using the Handy Whitman Index of Public Utility Construction Costs. For services, the investment costs are based on the installed cost for customers' typical size and type for each core customer class 101, 104 and 105. Similarly, the investment costs for meters and regulators are based on the installed average cost of metering and regulating equipment for these core classes utilizing current 2015 inventory prices. For the remaining larger customer classes 111, 170, 163, and the Special Contract class 900, the service, metering and regulating installations were specifically identified for each customer using the Cascade GIS system and then valued at current cost. Once the investment costs were derived, the incremental costs were computed by applying the ECCR to the investment costs. The derivation of the LRIC for services and meters is presented in Exhibit CNG/303.

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

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

Q. Please explain the ECCR.

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

B. Incremental Operating & Maintenance Expenses

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

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

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

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

The Gas Control function entails the 24-hour daily monitoring and management of the flow of gas on the Cascade pipeline system in Oregon. This is accomplished by gas control personnel through electronic monitoring of various points on the system via SCADA and Metretek measurement equipment. The SCADA sites are located at town border stations throughout the Cascade system and at one Special Contract customer

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location. Metretek monitoring equipment is located at non-core customer locations for classes 170, 163 and 900. The expenses charged to this function were first segregated between core and non-core classes according to a recent twelve-month study of recorded actionable items triggered by information provided by the SCADA and Metretek sites, and then allocated among the core and non-core classes using sales or transportation volumes, respectively. The results of the foregoing allocations of gas supply related O&M are shown on Line 26 of Exhibit CNG/304.

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

A. The category of incremental customer related O&M expenses includes Meter Reading (FERC Account 902); Customer Records and Collections, including monthly billing postage and printing (FERC Account 903); and Uncollectible Accounts (FERC Account 904), involving the following Cascade Responsibility Centers: Customer Services (RC 4767100, RC 4767200); Credit and Collections (RC 4767000); Revenue Accounting (RC 4760700); Information Systems (RC 4767800); and Oregon Districts (Bend RC 47041/47044), Pendleton (RC 47042), and Eastern Oregon (RC 47043).

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

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the foregoing allocations of customer service related O&M are shown on Line 45 of Exhibit CNG/304.

C. LRIC Summary of Results

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

A. Line 37 of Exhibit CNG/301 presents the total LRIC-based revenue requirement for each of Cascade's rate schedules. Line 32 of this Exhibit presents Test Year revenues by rate schedule under Cascade's current rates. By comparing these two sets of revenues, one can see the extent to which Cascade's current rates and non-gas revenues are reflective of LRIC. The revenue-to-cost ratios on line 38 of this exhibit portray the relative difference between these two revenue amounts for each rate schedule. A revenue-to-cost ratio of less than 1.00 means that the current rates and revenues of the particular rate schedule are below its indicated LRIC (*e.g.*, Rate Schedules 101, 105, 111, and 163), while a revenue-to-cost ratio of greater than 1.00 means that the rates and revenues of the rate schedule are above its indicated LRIC (*e.g.*, Rate Schedules 104, 170 and Special Contract Class 900). These results provide cost guidelines for use in evaluating a utility's class revenue levels and rate structures. I will describe later in my testimony how these results were used to assign Cascade's proposed revenue increase to its rate classes.

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

A. Exhibit CNG/302 shows how the pro forma results of Cascade's operations, including the requested revenue increase discussed in Company witness Mr. Parvinen's Exhibit CNG/201, have been assigned to the functional components used in the LRIC.

IV. PRINCIPLES OF SOUND RATE DESIGN

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

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

1. Efficiency;
2. Cost of Service;
3. Value of Service;
4. Stability;
5. Non-Discrimination;
6. Administrative Simplicity; and
7. Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in *Principles of Public Utility Rates*.[1] Each of these principles plays an important role in analyzing the rate design proposals of Cascade.

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

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Q. Please discuss the principle of efficiency.

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

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

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

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Q. Please discuss the principle of stability.

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

Q. Please discuss the concept of non-discrimination.

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

This principle recognizes that the ratemaking process requires discrimination where there are factors at work that cause the discrimination to be useful in accomplishing other objectives. For example, considerations such as the location, type of meter and service, demand characteristics, size, and a variety of other factors are often recognized in the design of utility rates to properly distribute the total cost of service to and within customer classes. This concept is also directly related to the concepts of vertical and horizontal equity. The principle of horizontal equity requires that "equals should be treated equally" and vertical equity requires that "unequals should be treated unequally." Specifically, these principles of equity require that where cost of service is equal—rates should be equal and, where costs are different—rates should be different. In this case, this principle is an important requirement that supports Cascade's proposed use of a single monthly Basic Service Charge for all customers within certain of its rate schedules, because delivery costs are identical for its residential customers and for its smallest commercial customers.

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Q. Please discuss the principle of administrative simplicity.

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

Q. Please discuss the principle of the balanced budget.

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

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

A. Yes, like most principles that have broad application, these principles can compete with each other. This competition or tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design alternatives and rate design recommendations must recognize the potential and actual competition between these principles. Indeed, Bonbright discusses this tension in detail. Rate design recommendations must deal effectively with such tension. For example, as noted above, there are tensions between cost and value of service principles.

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

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

In the case of a local distribution company (LDC) such as Cascade, for residential and small commercial customers, the combination of scale economies and class homogeneity may permit the use of a single fixed monthly charge that meets all of the requirements for an efficient rate that recovers the utility's revenue requirement that is derived on an embedded cost basis. For larger customers, a combination of these elements permit proper price signals and revenue recovery; however, the tariff design becomes more difficult to structure and likely will no longer meet the requirements of simplicity. Therefore, sacrificing some economic efficiency for a customer class in order to maintain simplicity represents a reasonable compromise. For larger customers, the

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added complexity of a demand charge may not be a concern. Further, for the largest customers, the cost of metering is customer-specific and each customer creates its own unique requirements for gas distribution service based on factors such as distance from the utility's city gate, pressure requirements, and contract demand levels.

Q. Are there other potential conflicts?

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

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

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

- Capital Attraction,
- Consumer Rationing, and
- Fairness to Ratepayers.[2]

These three criteria are basically a subset of the list of principles above and serve to emphasize fundamental considerations in designing public utility rates. Capital attraction is a combination of an equitable rate of return on rate base and the reasonable opportunity to earn the allowed rate of return. Consumer rationing requires that rates discourage wasteful use and promote all economically efficient use. Fairness to ratepayers reflects avoidance of undue discrimination and equity principles.

[2] *Id.* at 385.

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

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

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

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

The overall rate design process, which includes both the apportionment of the revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter into the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of

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necessity then, the rate design process has to be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. Please describe the approach generally followed to allocate Cascade's proposed revenue increase of $1.9 million to its rate classes.

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

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

A. Yes. Using Cascade's proposed revenue increase, and the results of its LRIC Study, I evaluated various options for the assignment of that increase among its rate classes and, in conjunction with Cascade personnel and management, ultimately decided upon one of those options as the preferred resolution of the interclass revenue issue. The first and benchmark option that I evaluated under Cascade's proposed total revenue level was to adjust the revenue level for each rate class so that the revenue-to-cost for each class was equal to 1.00. As a matter of judgment, it was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue. This

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decision was also made in consideration of the Bonbright rate design criteria discussed earlier. It should be pointed out, however, that those class revenue results represented an important guide for purposes of evaluating subsequent rate design options from a cost of service perspective.

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

Q. What was the next step in the process?

A. After further discussions with Cascade, I concluded that the appropriate interclass revenue proposal would be one that reflects increases in revenues to certain rate classes, guided by the results of Cascade's LRIC Study, with increases to these rate classes moderated by establishing a maximum increase level (on a percentage basis) above Cascade's proposed overall increase in non-gas revenues of 6.43%. This approach established a maximum non-gas revenue increase to any particular rate class of 32.16% (5.00 times 6.43%). Exhibit CNG/301 presents the derivation of Cascade's proposed class margin revenues by rate schedule on Line 48.

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This preferred revenue allocation approach resulted in reasonable movement of the class revenue-to-cost ratios towards unity or 1.00. That result is reflected in Exhibit CNG/301 on Line 50, wherein the revenue-to-cost ratios are shown to converge towards unity or 1.00 compared to the same measure calculated under current rates. In addition, the amounts of the existing rate subsidies among Cascade's rate classes were reduced for those classes that received increases in revenues. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable.

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

A. Yes. Exhibit CNG/305 presents a comparison of present and proposed revenues for each of Cascade's rate schedules.

VI. SUMMARY OF CASCADE'S RATE DESIGN PROPOSALS

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

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

- The establishment of a monthly Basic Service Charge for Schedule No. 111, Large Volume General Service, and Schedule No. 170, Interruptible Service, and the renaming of the current Dispatch Service Charge in the consolidated Schedule No.163 as a monthly Basic Service Charge.

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- For customers served under Schedule No. 105, General Industrial Service, and Schedule No. 163, Cascade proposes to adjust the monthly Basic Service Charges to better reflect the underlying costs of providing basic customer service as well as the proposed change in class revenues.

I will present below the specific rate design changes and supporting rationale for certain of Cascade's proposals, and Cascade witness Michael Parvinen will discuss the remaining components of the Company's proposed rate design.

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

A. In the interest of providing improved cost-based price signals to all of its classes of service, Cascade believes that it is appropriate for all service schedules to recover a portion of the customer-related incremental O&M and carrying costs of its incremental meter and service investment in a monthly Basic Service Charge. The LRIC Study provides a guide for this purpose. Line 54 of Exhibit CNG/301 shows the incremental customer-related O&M by class, including meter reading, customer account records and collection, billing and postage and uncollectible expenses. Line 53 of Exhibit CNG/301 adds the carrying charges on the meter and service investment by class to the incremental O&M. The cost values are stated on a per-month basis. This provides a range of incremental customer-related O&M cost recovery from which to design a monthly Basic Service Charge for each class of service. Cascade is proposing to establish the Basic Service Charge for Schedule No. 111 at $200.00 per month, approximately 27% of the upper range of incremental customer-related O&M and meter and service carrying charges for the class. The initial proposed Basic Service Charge for Schedule No. 170 was set at $300.00 per month, which

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collects the entire revenue increase for this class and is approximately 9% of the upper range of incremental customer-related O&M and meter and service carrying charges for the class.

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

A. The proposed monthly Basic Service Charge for Schedule No. 105 is $30.00, approximately 26% of the upper range of the incremental customer-related O&M and meter and service carrying charges for the class, as indicated in the LRIC Study. The renamed Basic Service Charge for proposed for Schedule No. 163 is $750.00, which raises the charge to within 40% of the upper range of the indicated incremental customer-related O&M and meter and service carrying charges for the class.

Q. Is Cascade proposing to increase the Basic Service Charge for any of the remaining Schedules?

A. No. Cascade wishes to leave the Basic Service Charges for Schedule No. 101, General Residential Service, and Schedule No. 104, General Commercial Service, at their current $3.00 per month level. At this level, the Basic Service Charge for these two classes of service will recover the monthly customer-related O&M, as indicated by the LRIC Study. Cascade witness Michael Parvinen will discuss this decision further in his testimony.

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

A. Yes. Exhibit CNG/306 shows the derivation of each rate component for each of Cascade's service schedules.

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

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

VII. CUSTOMER BILL IMPACTS

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

A. The monthly and annual bill impacts for a typical residential customer using 659 therms per year is shown on Exhibit CNG/307 The average monthly increase for this residential customer under the Company's proposed rate design is $2.07 or 4.10%. Average monthly residential bill impacts are depicted on page 1 of Exhibit CNG/307 and bill impacts over varying monthly levels of usage is presented on page 1 of Exhibit CNG/308.

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

A. Yes. Pages 2 through 6 of Exhibit CNG/308 presents bill comparisons for Cascade's non-residential service schedules at varying monthly levels of gas usage.

Q. Does this conclude your direct testimony?

A. Yes.

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BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 301

Summary of LRIC

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

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core
1	Billing Determinants								
2	Peak Day Forecast	91,882	52,034	35,256	2,906	1,686	-	-	-
3	Customer Count	70,743	60,662	9,901	128	13	31	4	4
4	Throughput	31,599,959	3,996,951	2,811,784	254,327	156,543	3,272,979	243,922	20,863,452
5	O&M Costs								
6	Gas Supply Related								
7	Gas Planning	$ 21,037	$ 9,609	$ 6,556	$ 550	$ 323	$ 528	$ 107	$ 3,364
8	Gas Supply	$ 42,749	$ 17,007	$ 11,964	$ 1,082	$ 666	$ 1,491	$ 1,038	$ 9,502
9	Gas Control	$ 79,283	$ 32,689	$ 22,996	$ 2,080	$ 1,280	$ 5,241	$ 1,995	$ 13,002
10	Customer Related								
11	Meter Reading	$ 251,985	$ 210,829	$ 34,410	$ 444	$ 1,606	$ 3,733	$ 482	$ 482
12	Customer Acoount records and collection	$ 1,153,862	$ 986,592	$ 161,026	$ 2,080	$ 217	$ 3,137	$ 405	$ 405
13	Billing Postage & Printing	$ 385,330	$ 330,420	$ 53,929	$ 697	$ 73	$ 169	$ 22	$ 22
14	Uncollectible	$ 361,003	$ 300,336	$ 60,462	$ 205	$ -	$ -	$ -	$ -
15	Subtotal: O&M Costs	$ 2,295,250	$ 1,887,480	$ 351,344	$ 7,139	$ 4,165	$ 14,299	$ 4,048	$ 26,776
16	Customer Investment Carrying Costs								
17	Meter	$ 5,309,590	$ 2,629,190	$ 1,703,949	$ 115,325	$ 100,422	$ 506,905	$ 113,299	$ 140,501
18	Service	$ 13,216,697	$ 10,925,277	$ 1,963,011	$ 60,688	$ 17,937	$ 187,602	$ 48,952	$ 13,230
19	Mains	$ 13,426,374	$ 5,915,660	$ 1,484,739	$ 1,136,781	$ 274,618	$ 2,626,560	$ 362,791	$ 1,625,225
20	Subtotal: Customer Investment Costs	$ 31,952,661	$ 19,470,127	$ 5,151,699	$ 1,312,794	$ 392,977	$ 3,321,067	$ 525,042	$ 1,778,955
21	System Core Main Carrying Costs								
22	Capacity	$ 39,638,178	$ 22,447,756	$ 15,209,317	$ 1,253,806	$ 727,300	$ -	$ -	$ -
23	Commodity	$ 11,925,744	$ 4,439,676	$ 3,123,233	$ 282,498	$ 173,883	$ 3,635,513	$ 270,941	$ -
24	Subtotal: System Core Main Costs	$ 51,563,922	$ 26,887,431	$ 18,332,550	$ 1,536,304	$ 901,183	$ 3,635,513	$ 270,941	$ -
25	LRIC - Distribution	$ 85,811,833	$ 48,245,039	$ 23,835,593	$ 2,856,236	$ 1,298,324	$ 6,970,879	$ 800,030	$ 1,805,732
26	Fuctional Cost Assignment by LRIC								
27	Scheduling & Planning	$ 143,069	$ 59,304	$ 41,516	$ 3,712	$ 2,270	$ 7,259	$ 3,140	$ 25,868
28	Meter Reading, Billing etc.	$ 2,152,181	$ 1,828,176	$ 309,828	$ 3,426	$ 1,895	$ 7,039	$ 908	$ 908
29	Meters, Services & Mains extensions	$ 31,952,661	$ 19,470,127	$ 5,151,699	$ 1,312,794	$ 392,977	$ 3,321,067	$ 525,042	$ 1,778,955
30	Sysctem Core Mains	$ 51,563,922	$ 26,887,431	$ 18,332,550	$ 1,536,304	$ 901,183	$ 3,635,513	$ 270,941	$ -
31	Total	$ 85,811,833	$ 48,245,039	$ 23,835,593	$ 2,856,236	$ 1,298,324	$ 6,970,879	$ 800,030	$ 1,805,732

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

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core
32	Non-Gas Revenue at Current Rates	$ 29,640,042	$ 16,926,173	$ 7,741,020	$ 505,501	$ 242,548	$ 2,159,441	$ 300,244	$ 1,765,115
33	Scheduling and Planning	$ 544,487	$ 225,698	$ 157,999	$ 14,129	$ 8,637	$ 27,627	$ 11,949	$ 98,447
34	Meter Reading & Billing	$ 3,756,032	$ 3,190,571	$ 540,719	$ 5,979	$ 3,307	$ 12,285	$ 1,585	$ 1,585
35	Meters & Services	$ 12,755,998	$ 7,772,777	$ 2,056,638	$ 524,088	$ 156,882	$ 1,325,822	$ 209,605	$ 710,187
36	Mains	$ 14,019,804	$ 7,180,111	$ 4,895,586	$ 410,260	$ 240,655	$ 970,840	$ 72,353	$ 250,000
37	Total LRIC Based Non-gas Rev Req.	$ 31,076,320	$ 18,369,156	$ 7,650,942	$ 954,455	$ 409,482	$ 2,336,574	$ 295,492	$ 1,060,219
38	Revenue to Cost Ratio	0.95	0.92	1.01	0.53	0.59	0.92	1.02	1.66
39	Incremental Non-gas Revenue Requirement	$ 1,906,285							
40	Step 1								
41	Increase relative to system average			-	5.00	4.00	1.25	-	-
42	Percent Increase	6.43%		0.00%	32.16%	25.73%	8.04%	0.00%	0.00%
43	Increase Step 1	$ 398,557		$ -	$ 162,555	$ 62,397	$ 173,604	$ -	$ -
44	Step 2								
45	Remainder allocated on Current Revenue	$ 16,926,173	$ 16,926,173	$ -	$ -	$ -	$ -	$ -	$ -
46	Increase Step 2	$ 1,507,728	$ 1,507,728	$ -	$ -	$ -	$ -	$ -	$ -
47	Total Non-gas Revenue Increase	$ 1,906,285	$ 1,507,728	$ -	$ 162,555	$ 62,397	$ 173,604	$ -	$ -
48	Non-Gas Revenue after Revenue Increase	$ 31,546,327	$ 18,433,901	$ 7,741,020	$ 668,057	$ 304,946	$ 2,333,045	$ 300,244	$ 1,765,115
49	Percent Increase		8.91%	0.00%	32.16%	25.73%	8.04%	0.00%	0.00%
50	Revenue to Cost Ratio		1.00	1.01	0.70	0.74	1.00	1.02	1.66
51	Final Increase relative to system average		1.39	-	5.00	4.00	1.25	-	-
52	LRIC Supported Customer Cost per month								
53	Cust O&M Plus Meter & Service Carrying Charge		$ 21.13	$ 33.47	$ 116.94	$ 751.59	$ 1,885.88	$ 3,399.15	$ 3,221.65
54	Cust O&M		$ 2.51	$ 2.61	$ 2.23	$ 11.84	$ 18.92	$ 18.92	$ 18.92

CNGC/302
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 302

Functional Revenue Requirement

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

No.	FERC	Description	2015 Results	Adjustments	Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains
		Plant In Service								
1		Intangible Plant	$ 187,041	$ 941,750	$ 1,128,791	Plant	$ -	$ -	$ 536,808	$ 591,983
2		Production Plant			$ -					
3		Storage Plant			$ -					
4		Transmission Plant	$ 5,900,639		$ 5,900,639					$ 5,900,639
5		Distribution Plant			$ -					$ -
6	374	Land and Land Rights	$ 223,037		$ 223,037					$ 223,037
7	375	Structures and Improvements	$ 363,785		$ 363,785					$ 363,785
8	376	Mains	$ 82,433,817	$ 5,710,753	$ 88,144,569					$ 88,144,569
9	377	Compressor Station			$ -					$ -
10	378	M & R Station Equipment	$ 7,895,830	$ 2,621,131	$ 10,516,961				$ 10,516,961	
11	380	Services	$ 46,742,011	$ 1,818,540	$ 48,560,551				$ 48,560,551	
12	381	Meters	$ 12,802,931	$ 1,084,336	$ 13,887,267				$ 13,887,267	
13	382	Meter Install	$ 8,242,825		$ 8,242,825				$ 8,242,825	
14	383	House Regulator & Install.	$ 2,583,471	$ 123,447	$ 2,706,918				$ 2,706,918	
15	385	Industrial M & R Station Equipment	$ 1,670,381	$ 226,964	$ 1,897,345				$ 1,897,345	
16	388	ARO - Distribution	$ 12,504,773		$ 12,504,773	Plant	$ -	$ -	$ 5,946,768	$ 6,558,006
17		General Plant	$ 12,200,707	$ 1,147,052	$ 13,347,759	Plant	$ -	$ -	$ 6,347,658	$ 7,000,101
18		Subtotal Plant In Service	$ 193,751,247	$ 13,673,972	$ 207,425,219		$ -	$ -	$ 98,643,099	$ 108,782,119
19		**Accumulated Depreciation**								
20		Intangible Plant	$ (2,032,242)		$ (2,032,242)	Plant	$ -	$ -	$ (966,452)	$ (1,065,789)
21		Production Plant			$ -					
22		Storage Plant			$ -					
23		Transmission Plant	$ (3,280,283)		$ (3,280,283)					$ (3,280,283)
24		Distribution Plant	$ (80,106,396)		$ (80,106,396)	DistPlant	$ -	$ -	$ (39,383,242)	$ (40,723,154)
25		General Plant	$ (5,954,748)		$ (5,954,748)	Plant	$ -	$ -	$ (2,831,839)	$ (3,122,909)
26		Test Year Accumulated Depreciation Adjustment		$ (6,365,348)	$ (6,365,348)	Plant	$ -	$ -	$ (3,027,104)	$ (3,338,244)
27		Subtotal Accumulated Depreciation	$ (91,373,668)	$ (6,365,348)	$ (97,739,016)		$ -	$ -	$ (46,208,637)	$ (51,530,379)
28		**Other Ratebase Items**								
29		Contributions in Aid of Construction	$ -	$ -	$ -					
30		Customer Adv. For Construction	$ (495,562)	$ -	$ (495,562)				$ (495,562)	
31		Deferred Accumulated Income Taxes	$ (26,536,580)	$ (70,305)	$ (26,606,885)	Plant	$ -	$ -	$ (12,653,165)	$ (13,953,720)
32		Deferred Debits	$ -	$ -	$ -					
33		Working Capital Allowance	$ 2,287,971	$ -	$ 2,287,971	Plant	$ -	$ -	$ 1,088,067	$ 1,199,904
34		Subtotal Other Ratebase	$ (24,744,171)	$ (70,305)	$ (24,814,476)		$ -	$ -	$ (12,060,660)	$ (12,753,816)

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

No.	FERC	Description	2015 Results	Adjustments	Total	Allocator	Gas Scheduling & Planning	Meter Reading & Billing	Meters & Services	System Core Mains
35		Total Ratebase	$ 77,633,407	$ 7,238,320	$ 84,871,727		$ -	$ -	$ 40,373,802	$ 44,497,925
36		Rate of Return			7.31%					
37		Return on Ratebase			$ 6,200,751		$ -	$ -	$ 2,949,721	$ 3,251,030
38		**Operating Expenses**								
39		Production	$ 108,233	$ 1,299	$ 109,532		$ 109,532			
40		Distribution								
41	870	Operation Supervision & Engineering	$ 502,211		$ 502,211	OpEx	$ 28,768	$ -	$ 204,465	$ 268,977.90
42	871	Distribution Load Dispatching	$ 140,032		$ 140,032		$ 140,032			
43	872	Compressor Station	$ -		$ -					$ -
44	874	Mains and Services Expenses	$ 1,073,812		$ 1,073,812					$ 1,073,812
45	875	Meas. & Reg. Station Expenses	$ 223,345		$ 223,345					$ 223,345
46	876	Meas. & Reg. Station Expenses - Ind	$ 12,145		$ 12,145					$ 12,145
47	878	Meter & House Regulator Expenses	$ 543,771		$ 543,771				$ 543,771	
48	879	Customer Installations Expenses	$ 451,504		$ 451,504				$ 451,504	
49	880	Other Expenses	$ 1,350,048		$ 1,350,048	OpEx	$ 77,333	$ -	$ 549,646	$ 723,068.61
50	881	Rents	$ 20,039		$ 20,039	Plant	$ -	$ -	$ 9,530	$ 10,509
51	885	Maint. Supervision & Engineering	$ 109,200		$ 109,200	MaintEx	$ -	$ -	$ 66,720	$ 42,480
52	886	Maint. of Structures & Improvements	$ 487		$ 487					$ 487
53	887	Maint. of Mains	$ 354,201		$ 354,201					$ 354,201
54	888	Maint. of Compressor Station Equip.	$ 781		$ 781					$ 781
55	889	Maint. of Meas. & Reg. Station Expenses-General	$ 33,903		$ 33,903					$ 33,903
56	890	Maint. of Meas. & Reg. Station Expenses-Indust.	$ 60,495		$ 60,495					$ 60,495
57	892	Maint. of Services	$ 331,052		$ 331,052				$ 331,052	
58	893	Maint. of Meters & House Regulators	$ 375,529		$ 375,529				$ 375,529	
59	894	Maint. of Other Equipment	$ 57,136		$ 57,136	MaintEx	$ -	$ -	$ 34,909	$ 22,226
60	NA	Distribution Adjustments	$ -	$ 97,202	$ 97,202	DistEx	$ 4,242	$ -	$ 44,245	$ 48,715
61		Customer Accounts	$ 1,709,474	$ 232,767	$ 1,942,241			$ 1,942,241		
62		Customer Service	$ 612,804	$ (506,656)	$ 106,148			$ 106,148		
63		Sales	$ 2,313	$ (19,501)	$ (17,189)			$ (17,189)		
64		Administrative and General	$ 5,451,075	$ 619,327	$ 6,070,401	O&M	$ 184,580	$ 1,724,832	$ 1,998,205	$ 2,162,785
65		Depreciation & Amortization	$ 6,111,512	$ 507,672	$ 6,619,184	Plant	$ -	$ -	$ 3,147,818	$ 3,471,366
66		Regulatory Debits	$ -	$ -	$ -	Plant	$ -	$ -	$ -	$ -
67		Taxes Other Than Income	$ 1,926,429	$ 200,857	$ 2,127,286	Plant	$ -	$ -	$ 1,011,652	$ 1,115,634
68		State & Federal Income Taxes	$ 1,356,152	$ 824,921	$ 2,181,073	Plant	$ -	$ -	$ 1,037,231	$ 1,143,842
69		Total Operating Expense	$ 22,917,681	$ 1,957,888	$ 24,875,569		$ 544,487	$ 3,756,032	$ 9,806,277	$ 10,768,774
70		Functionalized Revenue Requirement	$ 22,917,681	$ 1,957,888	$ 31,076,320		$ 544,487	$ 3,756,032	$ 12,755,998	$ 14,019,804

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 303

Incremental Plant Carrying Costs

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

				101	104	105	111	163	170	900	
				Residential	Commercial	Industrial	Large Volume	General		Special	
Line	Description	Unit	Total	Service	Service	Service	Service	Distribution	Interruptible	Contracts	Source
				core	core	core	core	non-core	core	non-core	
1	**Billing Determinants**										
2	Peak Day Forecast	Dth-Day	91,882	52,034	35,256	2,906	1,686	-	-	-	
3	Customer Count		70,743	60,662	9,901	128	13	31	4	4	
4	Throughput	Dth	31,599,959	3,996,951	2,811,784	254,327	156,543	3,272,979	243,922	20,863,452	
5	**Service Installation**										
6	Typical Size	in.		0.5	1	2					
7	Material			Plastic	Plastic	Plastic					
8	Average Cost	$		$ 1,089	$ 1,198	$ 2,868					RJA-1
9	Total Investment	$	$ 79,880,857	$ 66,031,665	$ 11,864,310	$ 366,796	$ 108,411	$ 1,133,852	$ 295,860	$ 79,962	RJA-5
10	Economic Carryin Charge Rate			16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	16.55%	
11	Annual Carrying Charge per customer	$		$ 180.10	$ 198.27	$ 474.60					
12	Class Annual Carrying Charge	$	$ 13,216,697	$ 10,925,277	$ 1,963,011	$ 60,688	$ 17,937	$ 187,602	$ 48,952	$ 13,230	
13	**Meters & Regulators**										
14	Average Cost	$		$ 225	$ 895	$ 4,690					RJA-2
15	Total Investment	$	$ 27,612,779	$ 13,673,227	$ 8,861,469	$ 599,753	$ 522,247	$ 2,636,185	$ 589,218	$ 730,680	RJA-5
16	Economic Carryin Charge Rate			19.23%	19.23%	19.23%	19.23%	19.23%	19.23%	19.23%	
17	Annual Carrying Charge per customer	$		$ 43.34	$ 172.10	$ 901.87					
18	Class Annual Carrying Charge	$	$ 5,309,590	$ 2,629,190	$ 1,703,949	$ 115,325	$ 100,422	$ 506,905	$ 113,299	$ 140,501	
19	**Mains Investment**										
20	A. Customer Mains Investment										
21	Typical Size	in.		2	2	2					
22	Material			Plastic	Plastic	Steel					
23	Avg. Mains extension per customer	ft		78.68	121.00	899.14					RJA-3E
24	Average cost per ft	$/ft		$ 7.81	$ 7.81	$ 62.34					RJA-3B
25	Customer mains investment per customer	$		$ 615	$ 945	$ 56,051					
26	Customer Mains Investment by Class		$ 84,653,033	$ 37,298,127	$ 9,361,249	$ 7,167,381	$ 1,731,462	$ 16,560,413	$ 2,287,390	$ 10,247,011	RJA-5
27	B. Capacity Related										
28	Incr. mains capacity investment	$	$ 430,987	$ 244,075	$ 165,371	$ 13,633	$ 7,908				RJA-3C
29	Capacity Mains Investment per customer	$		$ 4.02	$ 16.70	$ 106.61	$ 593.10				

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

Line	Description	Unit	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core	Source
30	C. Commodity (Safety) Related										
31	Incr. mains commodity investment/therm	$	$ 3,776,126	$ 1,405,763	$ 988,930	$ 89,449	$ 55,058	$ 1,151,136	$ 85,790		RJA-3D
32	Safety Related Investment per customer	$		$ 23.17	$ 99.88	$ 699.52	$ 4,129.33	$ 37,133.42	$ 21,447.42	$ -	
33	Long-Run System Replacement Investment										
34	Mains System Replacement Cost	$	$ 409,762,585								RJA-3A
35	Less: Customer Mains Investment	$	$ (88,860,146)								
36	Long-Run System Replacement Investment	$	$ 320,902,439								
37	Capacity	%	78%								
38	Investment per Peak Day Capacity	$/Dth-Day	$ 2,715								
39	Investment by Class	$	$ 249,486,977	$ 141,288,599	$ 95,729,086	$ 7,891,589	$ 4,577,703	$ -	$ -	$ -	
40	Investment per customer	$		$ 2,329	$ 9,669	$ 61,715	$ 343,328	$ -	$ -	$ -	
41	Commodity	%	22%								
42	System Replacement Investment per Dth	$/Dth	$ 6.65								
43	Investment by Class	$	$ 71,415,463	$ 26,586,309	$ 18,702,996	$ 1,691,696	$ 1,041,271	$ 21,770,705	$ 1,622,486		
44	Investment per customer	$		$ 438	$ 1,889	$ 13,230	$ 78,095	$ 702,281	$ 405,621	$ -	
45	Total mains investment by class	$	$ 409,762,585	$ 206,822,873	$ 124,947,632	$ 16,853,748	$ 7,413,402	$ 39,482,254	$ 3,995,666	$ 10,247,011	
46	Economic Carryin Charge Rate			15.86%	15.86%	15.86%	15.86%	15.86%	15.86%	15.86%	
47	Class Annual Carrying Charge	$	$ 64,990,296	$ 32,803,092	$ 19,817,289	$ 2,673,085	$ 1,175,801	$ 6,262,073	$ 633,732	$ 1,625,225	
48	**Total Carrying Costs**		**$ 83,516,583**	**$ 46,357,558**	**$ 23,484,249**	**$ 2,849,098**	**$ 1,294,160**	**$ 6,956,580**	**$ 795,982**	**$ 1,778,955**	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 304

Incremental O&M Costs

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

Line	Description	Total	101 Residential Service core	104 Commercial Service core	105 Industrial Service core	111 Large Volume Service core	163 General Distribution non-core	170 Interruptible core	900 Special Contracts non-core	Source
1	**Billing Determinants**									
2	Peak Day Forecast	91,882	52,034	35,256	2,906	1,686	-	-	-	
3	Customer Count	70,743	60,662	9,901	128	13	31	4	4	
4	Throughput	31,599,959	3,996,951	2,811,784	254,327	156,543	3,272,979	243,922	20,863,452	
5	Sales	7,463,528	3,996,951	2,811,784	254,327	156,543		243,922		
6	Peak & Average	100%	35%	24%	2%	1%	5%	0%	33%	
7	Customer Count (Small Customers)	70,690	60,662	9,901	128					
8	Customer Count (Large Customers)	52				13	31	4	4	
9	Volumes (Core)		3,996,951	2,811,784	254,327	156,543		243,922		
10	Volumes (Non-core)						3,272,979		20,863,452	
11	**Gas Planning**									
12	Core	$ 17,145	$ 9,609	$ 6,556	$ 550	$ 323		$ 107		RJA-4A
13	Non-core	$ 3,892					$ 528		$ 3,364	RJA-4A
14	Total Core + Non-core	$ 21,037	$ 9,609	$ 6,556	$ 550	$ 323	$ 528	$ 107	$ 3,364	
15	Cost per customer		$ 0.16	$ 0.66	$ 4.30	$ 24.24	$ 17.02	$ 26.76	$ 841.02	
16	**Gas Supply**									
17	Core	$ 31,757	$ 17,007	$ 11,964	$ 1,082	$ 666		$ 1,038		RJA-4A
18	Non-core	$ 10,993					$ 1,491		$ 9,502	RJA-4A
19	Total Core + Non-core	$ 42,749	$ 17,007	$ 11,964	$ 1,082	$ 666	$ 1,491	$ 1,038	$ 9,502	
20	Cost per Cust		$ 0.28	$ 1.21	$ 8.46	$ 49.96	$ 48.09	$ 259.47	$ 2,375.51	
21	**Gas Control**									
22	Core	$ 61,040	$ 32,689	$ 22,996	$ 2,080	$ 1,280		$ 1,995		
23	Non-core	$ 18,243					$ 5,241		$ 13,002	RJA-4A
24	Total Core + Non-core	$ 79,283	$ 32,689	$ 22,996	$ 2,080	$ 1,280	$ 5,241	$ 1,995	$ 13,002	RJA-4A
25	Cost per Cust		$ 0.54	$ 2.32	$ 16.27	$ 96.02	$ 169.06	$ 498.73	$ 3,250.43	
26	**Total Gas Supply O&M**	**$ 143,069**	**$ 59,304**	**$ 41,516**	**$ 3,712**	**$ 2,270**	**$ 7,259**	**$ 3,140**	**$ 25,868**	

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

Line	Description	Total	101	104	105	111	163	170	900	Source
			Residential Service	Commercial Service	Industrial Service	Large Volume Service	General Distribution	Interruptible	Special Contracts	
			core	core	core	core	non-core	core	non-core	
27	**Meter Reading**									
28	Meter Reading Expense (Res + Small Comm.)	$ 245,683	$ 210,829	$ 34,410	$ 444	$ -	$ -	$ -	$ -	RJA-4B
29	Meter Reading Expense (Industrial)	$ 6,302	$ -	$ -	$ -	$ 1,606	$ 3,733	$ 482	$ 482	RJA-4B
30	Meter Reading Expense	$ 251,985	$ 210,829	$ 34,410	$ 444	$ 1,606	$ 3,733	$ 482	$ 482	
31	Cost per customer		$ 3.48	$ 3.48	$ 3.48	$ 120.42	$ 120.42	$ 120.42	$ 120.42	
32	**Customer Acoount records and collection**									
33	Expense	$ 1,149,915	$ 986,592	$ 161,026	$ 2,080	$ 217				
34	Expense - Manual Billing	$ 3,947					$ 3,137	$ 405	$ 405	RJA-4C
35	Cost per customer		$ 16.26	$ 16.26	$ 16.26	$ 16.26	$ 101.20	$ 101.20	$ 101.20	RJA-4C
36	**Billing Postage & Printing**									
37	Expense	$ 385,330	$ 330,420	$ 53,929	$ 697	$ 73	$ 169	$ 22	$ 22	RJA-4D
38	Cost per customer		$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	$ 5.45	
39	**Uncollectible**									
40	COMMERCIAL	$ 60,462		$ 60,462						RJA-4E
41	INDUSTRIAL	$ 205			$ 205					RJA-4E
42	RESIDENTIAL	$ 300,336	$ 300,336							RJA-4E
43	Total OR	$ 361,003	$ 300,336	$ 60,462	$ 205	$ -	$ -	$ -	$ -	
44	Cost per customer		$ 4.95	$ 6.11	$ 1.61	$ -	$ -	$ -	$ -	
45	**Total Customer O&M**	**$ 2,152,181**	**$ 1,828,176**	**$ 309,828**	**$ 3,426**	**$ 1,895**	**$ 7,039**	**$ 908**	**$ 908**	
46	Gas Contral O&M Allocation to Non-core						28.7%		71.3%	RJA-4F

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 305

Summary of Revenue by Rate Class

Summary of Revenue by Rate Class
Present and Proposed Rates

Customer Class	Revenues			
	Pro Forma	**Proposed**	**$ Difference**	**% Difference**
Residential - 101				
Basic Service Charge	$ 2,183,820	$ 2,183,820	$ -	0%
Delivery Charge	14,742,354	16,250,004	1,507,650	10%
Rounding Difference	-	78	-	
Total 101 Revenue	$ 16,926,173	$ 18,433,901	$ 1,507,728	9%
Commercial - 104				
Basic Service Charge	$ 356,432	$ 356,432	$ -	0%
Delivery Charge	7,384,588	7,384,588	-	0%
Rounding Difference	-	-	-	
Total 104 Revenue	$ 7,741,020	$ 7,741,020	$ -	0%
Industrial - 105				
Basic Service Charge	$ 18,414	$ 46,034	$ 27,620	150%
Delivery Charge	487,088	622,034	134,946	28%
Rounding Difference	-	(11)	-	
Total 105 Revenue	$ 505,501	$ 668,057	$ 162,555	32%
Large Volume - 111				
Basic Service Charge	$ -	$ 32,000	$ 32,000	n/a
Delivery Charge	242,548	272,949	30,401	13%
Rounding Difference	-	(3)	-	
Total 111 Revenue	$ 242,548	$ 304,946	$ 62,397	26%
General Distribution - 163				
Basic Service Charge	$ 186,000	$ 279,000	$ 93,000	50%
Delivery Charge	1,973,441	2,054,102	80,662	4%
Rounding Difference	-	(57)	-	
Total 163 Revenue	$ 2,159,441	$ 2,333,045	$ 173,604	8%
Interruptible - 170				
Basic Service Charge	$ -	$ 14,400	$ 14,400	n/a
Delivery Charge	300,244	285,853	(14,391)	-5%
Rounding Difference	-	(9)	-	
Total 170 Revenue	$ 300,244	$ 300,244	$ -	0%
Special Contracts - 9xx				
Basic Service Charge	$ 24,000	$ 24,000	$ -	0%
Delivery Charge	572,315	572,315	(0)	0%
Demand Charge	1,168,799	1,168,799	(0)	
Rounding Difference	-	-	-	
Total 9xx Revenue	$ 1,765,115	$ 1,765,114	$ (0)	0%
TOTAL	$ 29,640,042	$ 31,546,327	$ 1,906,285	

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 306

Analysis of Revenue by Detailed Rate Schedule

Cascade Natural Gas Corporation
Oregon Jurisdiction
Test Year Ended December 31, 2015

Analysis of Revenue by Detailed Rate Schedule

Customer Class	Pro Forma Test Year Revenues: Billing Units*	Present Rate	Revenue	Proposed Revenues: Proposed Rates	Revenue	Difference: $ Amount	% Amount
Residential - 101	60,662						
Basic Service Charge	727,940	$3.00	$ 2,183,820	$3.00	$ 2,183,820	$ -	0%
Delivery Charge	39,969,509	$0.36884	$ 14,742,354	$0.40656	$ 16,250,004	$ 1,507,650	10%
Rounding Difference					$ 78	$ 78	
Total 101 Revenue			**$ 16,926,173**		**$ 18,433,901**	**$ 1,507,728**	9%
Commercial - 104	9,901						
Basic Service Charge	118,811	$3.00	$ 356,432	$3.00	$ 356,432	$ -	0%
Delivery Charge	28,117,840	$0.26263	$ 7,384,588	$0.26263	$ 7,384,588	$ -	0%
Rounding Difference					$ -	$ -	
Total 104 Revenue			**$ 7,741,020**		**$ 7,741,020**	**$ -**	0%
Industrial - 105	128						
Basic Service Charge	1,534	$12.00	$ 18,414	$30.00	$ 46,034	$ 27,620	150%
Delivery Charge	2,543,274	$0.19152	$ 487,088	$0.24458	$ 622,034	$ 134,946	28%
Rounding Difference					$ (11)	$ (11)	
Total 105 Revenue			**$ 505,501**		**$ 668,057**	**$ 162,555**	32%
Large Volume - 111	13.33						
Basic Service Charge	160	$0.00	$ -	$200.00	$ 32,000	$ 32,000	
Delivery Charge	1,565,433	$0.15494	$ 242,548	$0.17436	$ 272,949	$ 30,401	13%
Rounding Difference					$ (3)	$ (3)	
Total 111 Revenue			**$ 242,548**		**$ 304,946**	**$ 62,397**	26%
General Distribution - 163	31						
Basic Service Charge	372	$500.00	$ 186,000	$750.00	$ 279,000	$ 93,000	50%
Delivery Charge - first 10,000 therms	3,221,176	$0.12402	$ 399,490	$0.12909	$ 415,822	$ 16,331	4%
Delivery Charge - next 10,000 therms	2,500,576	$0.11188	$ 279,764	$0.11645	$ 291,192	$ 11,428	4%
Delivery Charge - next 30,000 therms	4,413,295	$0.10512	$ 463,926	$0.10941	$ 482,859	$ 18,933	4%
Delivery Charge - next 50,000 therms	4,000,770	$0.06456	$ 258,290	$0.06720	$ 268,852	$ 10,562	4%
Delivery Charge - next 400,000 therms	16,160,944	$0.03275	$ 529,271	$0.03409	$ 550,927	$ 21,656	4%
Delivery Charge - over 500,000 therms	2,433,032	$0.01755	$ 42,700	$0.01827	$ 44,451	$ 1,752	4%
Rounding Difference					$ (57)	$ (57)	
Total 163 Revenue			**$ 2,159,441**		**$ 2,333,045**	**$ 173,604**	8%
Interruptible - 170	4						
Basic Service Charge	48	$0.00	$ -	$300.00	$ 14,400	$ 14,400	
Delivery Charge	2,439,224	$0.12309	$ 300,244	$0.11719	$ 285,853	$ (14,391)	-5%
Rounding Difference					$ (9)	$ (9)	
Total 170 Revenue			**$ 300,244**		**$ 300,244**	**$ -**	0%

*** Delivery Charge units are in therms**

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 307

Residential Impact by Month

Residential - 101

Line No.	(a)	(b)	(c) Present Rates	(d) Proposed Rates	(e)	(f)
1	Basic Service Charge		$3.00	$3.00		
2	Delivery Charge		$0.36884	$0.40656		
3	PGA Rate		$0.49633	$0.49633		

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	104	$ 92.98	$ 96.90	$ 3.92	4.22%
5	February	89	$ 80.00	$ 83.36	$ 3.36	4.20%
6	March	70	$ 63.56	$ 66.20	$ 2.64	4.15%
7	April	51	$ 47.12	$ 49.05	$ 1.92	4.08%
8	May	33	$ 31.55	$ 32.80	$ 1.24	3.95%
9	June	19	$ 19.44	$ 20.15	$ 0.72	3.69%
10	July	15	$ 15.98	$ 16.54	$ 0.57	3.54%
11	August	15	$ 15.98	$ 16.54	$ 0.57	3.54%
12	September	22	$ 22.03	$ 22.86	$ 0.83	3.77%
13	October	46	$ 42.80	$ 44.53	$ 1.74	4.05%
14	November	81	$ 73.08	$ 76.13	$ 3.06	4.18%
15	December	114	$ 101.63	$ 105.93	$ 4.30	4.23%
16	Total	659	$ 606.15	$ 631.00	$ 24.86	
17	Monthly Average		$ 50.51	$ 52.58	$ 2.07	4.10%

CNGC/308
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 308

Impact of Recommended Rate Changes

Residential - 101

Line No.	(a)	(b)	(c)	(d)	(e)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$3.00	$3.00		
2	Delivery Charge	$0.36884	$0.40656		
3	PGA Rate	$0.49633	$0.49633		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$3.00	$3.00	$0.00	0.00%
5	25	$24.63	$25.57	$0.94	3.83%
6	30	$28.96	$30.09	$1.13	3.91%
7	35	$33.28	$34.60	$1.32	3.97%
8	40	$37.61	$39.12	$1.51	4.01%
9	45	$41.93	$43.63	$1.70	4.05%
10	50	$46.26	$48.14	$1.89	4.08%
11	60	$54.91	$57.17	$2.26	4.12%
12	70	$63.56	$66.20	$2.64	4.15%
13	80	$72.21	$75.23	$3.02	4.18%
14	90	$80.87	$84.26	$3.39	4.20%
15	100	$89.52	$93.29	$3.77	4.21%
16	110	$98.17	$102.32	$4.15	4.23%
17	120	$106.82	$111.35	$4.53	4.24%
18	130	$115.47	$120.38	$4.90	4.25%
19	140	$124.12	$129.40	$5.28	4.25%
20	150	$132.78	$138.43	$5.66	4.26%
21	160	$141.43	$147.46	$6.04	4.27%
22	170	$150.08	$156.49	$6.41	4.27%
23	180	$158.73	$165.52	$6.79	4.28%
24	190	$167.38	$174.55	$7.17	4.28%
25	200	$176.03	$183.58	$7.54	4.29%
26	210	$184.69	$192.61	$7.92	4.29%
27	220	$193.34	$201.64	$8.30	4.29%
28	230	$201.99	$210.66	$8.68	4.30%
29	240	$210.64	$219.69	$9.05	4.30%
30	250	$219.29	$228.72	$9.43	4.30%

Commercial - 104

Line No.	(a)	(b) Present Rates	(d) Proposed Rates	(e)	(f)
1	Basic Service Charge	$3.00	$3.00		
2	Delivery Charge	$0.26263	$0.26263		
3	PGA Rate	$0.49633	$0.49633		

	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$3.00	$3.00	$0.00	0.00%
5	50	$40.95	$40.95	$0.00	0.00%
6	60	$48.54	$48.54	$0.00	0.00%
7	70	$56.13	$56.13	$0.00	0.00%
8	80	$63.72	$63.72	$0.00	0.00%
9	90	$71.31	$71.31	$0.00	0.00%
10	100	$78.90	$78.90	$0.00	0.00%
11	110	$86.49	$86.49	$0.00	0.00%
12	120	$94.08	$94.08	$0.00	0.00%
13	130	$101.66	$101.66	$0.00	0.00%
14	140	$109.25	$109.25	$0.00	0.00%
15	150	$116.84	$116.84	$0.00	0.00%
16	160	$124.43	$124.43	$0.00	0.00%
17	170	$132.02	$132.02	$0.00	0.00%
18	180	$139.61	$139.61	$0.00	0.00%
19	190	$147.20	$147.20	$0.00	0.00%
20	200	$154.79	$154.79	$0.00	0.00%
21	250	$192.74	$192.74	$0.00	0.00%
22	300	$230.69	$230.69	$0.00	0.00%
23	350	$268.64	$268.64	$0.00	0.00%
24	400	$306.58	$306.58	$0.00	0.00%
25	450	$344.53	$344.53	$0.00	0.00%
26	500	$382.48	$382.48	$0.00	0.00%
27	600	$458.38	$458.38	$0.00	0.00%
28	700	$534.27	$534.27	$0.00	0.00%
29	800	$610.17	$610.17	$0.00	0.00%
30	1,000	$761.96	$761.96	$0.00	0.00%
31	1,250	$951.70	$951.70	$0.00	0.00%
32	1,500	$1,141.44	$1,141.44	$0.00	0.00%
33	1,750	$1,331.18	$1,331.18	$0.00	0.00%
34	2,000	$1,520.92	$1,520.92	$0.00	0.00%
35	2,500	$1,900.40	$1,900.40	$0.00	0.00%
36	3,000	$2,279.88	$2,279.88	$0.00	0.00%
37	3,500	$2,659.36	$2,659.36	$0.00	0.00%
38	4,000	$3,038.84	$3,038.84	$0.00	0.00%

Industrial - 105

Line No.	(a)	(b) Present Rates	(d) Proposed Rates
1	Basic Service Charge	$12.00	$30.00
2	Delivery Charge	$0.19152	$0.24458
3	PGA Rate	$0.49633	$0.49633

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$12.00	$30.00	$18.00	150.00%
5	100	$80.79	$104.09	$23.31	28.85%
6	200	$149.57	$178.18	$28.61	19.13%
7	300	$218.36	$252.27	$33.92	15.53%
8	400	$287.14	$326.36	$39.22	13.66%
9	500	$355.93	$400.46	$44.53	12.51%
10	600	$424.71	$474.55	$49.84	11.73%
11	700	$493.50	$548.64	$55.14	11.17%
12	800	$562.28	$622.73	$60.45	10.75%
13	900	$631.07	$696.82	$65.75	10.42%
14	1,000	$699.85	$770.91	$71.06	10.15%
15	1,100	$768.64	$845.00	$76.37	9.94%
16	1,200	$837.42	$919.09	$81.67	9.75%
17	1,300	$906.21	$993.18	$86.98	9.60%
18	1,400	$974.99	$1,067.27	$92.28	9.47%
19	1,500	$1,043.78	$1,141.37	$97.59	9.35%
20	2,000	$1,387.70	$1,511.82	$124.12	8.94%
21	2,500	$1,731.63	$1,882.28	$150.65	8.70%
22	3,000	$2,075.55	$2,252.73	$177.18	8.54%
23	3,500	$2,419.48	$2,623.19	$203.71	8.42%
24	4,000	$2,763.40	$2,993.64	$230.24	8.33%
25	5,000	$3,451.25	$3,734.55	$283.30	8.21%
26	6,000	$4,139.10	$4,475.46	$336.36	8.13%
27	7,000	$4,826.95	$5,216.37	$389.42	8.07%
28	8,000	$5,514.80	$5,957.28	$442.48	8.02%
29	9,000	$6,202.65	$6,698.19	$495.54	7.99%
30	10,000	$6,890.50	$7,439.10	$548.60	7.96%
31	12,500	$8,610.13	$9,291.38	$681.25	7.91%
32	15,000	$10,329.75	$11,143.65	$813.90	7.88%
33	17,500	$12,049.38	$12,995.93	$946.55	7.86%
34	20,000	$13,769.00	$14,848.20	$1,079.20	7.84%
35	25,000	$17,208.25	$18,552.75	$1,344.50	7.81%
36	30,000	$20,647.50	$22,257.30	$1,609.80	7.80%
37	35,000	$24,086.75	$25,961.85	$1,875.10	7.78%
38	40,000	$27,526.00	$29,666.40	$2,140.40	7.78%
39	45,000	$30,965.25	$33,370.95	$2,405.70	7.77%
40	50,000	$34,404.50	$37,075.50	$2,671.00	7.76%
41	60,000	$41,283.00	$44,484.60	$3,201.60	7.76%
42	70,000	$48,161.50	$51,893.70	$3,732.20	7.75%
43	80,000	$55,040.00	$59,302.80	$4,262.80	7.74%
44	90,000	$61,918.50	$66,711.90	$4,793.40	7.74%
45	100,000	$68,797.00	$74,121.00	$5,324.00	7.74%

Large Volume - 111

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$0.00	$200.00		
2	Delivery Charge	$0.15494	$0.17436		
3	PGA Rate	$0.49633	$0.49633		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$0.00	$200.00	$200.00	
5	100	$65.13	$267.07	$201.94	310.07%
6	200	$130.25	$334.14	$203.88	156.53%
7	300	$195.38	$401.21	$205.83	105.35%
8	400	$260.51	$468.28	$207.77	79.75%
9	500	$325.64	$535.35	$209.71	64.40%
10	600	$390.76	$602.41	$211.65	54.16%
11	700	$455.89	$669.48	$213.59	46.85%
12	800	$521.02	$736.55	$215.54	41.37%
13	900	$586.14	$803.62	$217.48	37.10%
14	1,000	$651.27	$870.69	$219.42	33.69%
15	1,100	$716.40	$937.76	$221.36	30.90%
16	1,200	$781.52	$1,004.83	$223.30	28.57%
17	1,300	$846.65	$1,071.90	$225.25	26.60%
18	1,400	$911.78	$1,138.97	$227.19	24.92%
19	1,500	$976.91	$1,206.04	$229.13	23.45%
20	2,000	$1,302.54	$1,541.38	$238.84	18.34%
21	2,500	$1,628.18	$1,876.73	$248.55	15.27%
22	3,000	$1,953.81	$2,212.07	$258.26	13.22%
23	3,500	$2,279.45	$2,547.42	$267.97	11.76%
24	4,000	$2,605.08	$2,882.76	$277.68	10.66%
25	5,000	$3,256.35	$3,553.45	$297.10	9.12%
26	6,000	$3,907.62	$4,224.14	$316.52	8.10%
27	7,000	$4,558.89	$4,894.83	$335.94	7.37%
28	8,000	$5,210.16	$5,565.52	$355.36	6.82%
29	9,000	$5,861.43	$6,236.21	$374.78	6.39%
30	10,000	$6,512.70	$6,906.90	$394.20	6.05%
31	12,500	$8,140.88	$8,583.63	$442.75	5.44%
32	15,000	$9,769.05	$10,260.35	$491.30	5.03%
33	17,500	$11,397.23	$11,937.08	$539.85	4.74%
34	20,000	$13,025.40	$13,613.80	$588.40	4.52%
35	25,000	$16,281.75	$16,967.25	$685.50	4.21%
36	30,000	$19,538.10	$20,320.70	$782.60	4.01%
37	35,000	$22,794.45	$23,674.15	$879.70	3.86%
38	40,000	$26,050.80	$27,027.60	$976.80	3.75%
39	45,000	$29,307.15	$30,381.05	$1,073.90	3.66%
40	50,000	$32,563.50	$33,734.50	$1,171.00	3.60%
41	60,000	$39,076.20	$40,441.40	$1,365.20	3.49%
42	70,000	$45,588.90	$47,148.30	$1,559.40	3.42%
43	80,000	$52,101.60	$53,855.20	$1,753.60	3.37%
44	90,000	$58,614.30	$60,562.10	$1,947.80	3.32%
45	100,000	$65,127.00	$67,269.00	$2,142.00	3.29%

General Distribution - 163

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$500.00	$750.00		
2	Delivery Charge				
3	First 10,000 therms	$0.12402	$0.12909		
4	Next 10,000 therms	$0.11188	$0.11645		
5	Next 30,000 therms	$0.10512	$0.10941		
6	Next 50,000 therms	$0.06456	$0.06720		
7	Next 400,000 therms	$0.03275	$0.03409		
8	Over 500,000 therms	$0.01755	$0.01827		
9	PGA Rate	$0.00000	$0.00000		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change	
				Amount	Percent
10	0	$500.00	$750.00	$250.00	50.00%
11	2,000	$748.04	$1,008.18	$260.14	34.78%
12	4,000	$996.08	$1,266.36	$270.28	27.13%
13	6,000	$1,244.12	$1,524.54	$280.42	22.54%
14	8,000	$1,492.16	$1,782.72	$290.56	19.47%
15	10,000	$1,740.20	$2,040.90	$300.70	17.28%
16	12,000	$1,963.96	$2,273.80	$309.84	15.78%
17	14,000	$2,187.72	$2,506.70	$318.98	14.58%
18	16,000	$2,411.48	$2,739.60	$328.12	13.61%
19	18,000	$2,635.24	$2,972.50	$337.26	12.80%
20	20,000	$2,859.00	$3,205.40	$346.40	12.12%
21	25,000	$3,384.60	$3,752.45	$367.85	10.87%
22	30,000	$3,910.20	$4,299.50	$389.30	9.96%
23	35,000	$4,435.80	$4,846.55	$410.75	9.26%
24	40,000	$4,961.40	$5,393.60	$432.20	8.71%
25	45,000	$5,487.00	$5,940.65	$453.65	8.27%
26	50,000	$6,012.60	$6,487.70	$475.10	7.90%
27	60,000	$6,658.20	$7,159.70	$501.50	7.53%
28	70,000	$7,303.80	$7,831.70	$527.90	7.23%
29	80,000	$7,949.40	$8,503.70	$554.30	6.97%
30	90,000	$8,595.00	$9,175.70	$580.70	6.76%
31	100,000	$9,240.60	$9,847.70	$607.10	6.57%
32	125,000	$10,059.35	$10,699.95	$640.60	6.37%
33	150,000	$10,878.10	$11,552.20	$674.10	6.20%
34	175,000	$11,696.85	$12,404.45	$707.60	6.05%
35	200,000	$12,515.60	$13,256.70	$741.10	5.92%
36	250,000	$14,153.10	$14,961.20	$808.10	5.71%
37	300,000	$15,790.60	$16,665.70	$875.10	5.54%
38	350,000	$17,428.10	$18,370.20	$942.10	5.41%
39	400,000	$19,065.60	$20,074.70	$1,009.10	5.29%
40	450,000	$20,703.10	$21,779.20	$1,076.10	5.20%
41	500,000	$22,340.60	$23,483.70	$1,143.10	5.12%
42	600,000	$24,095.60	$25,310.70	$1,215.10	5.04%
43	700,000	$25,850.60	$27,137.70	$1,287.10	4.98%
44	800,000	$27,605.60	$28,964.70	$1,359.10	4.92%
45	900,000	$29,360.60	$30,791.70	$1,431.10	4.87%
46	1,000,000	$31,115.60	$32,618.70	$1,503.10	4.83%

Interruptible - 170

Line No.	(a)	(b)	(d)	(e)	(f)
		Present Rates	Proposed Rates		
1	Basic Service Charge	$0.00	$300.00		
2	Delivery Charge	$0.12309	$0.11719		
3	PGA Rate	$0.49633	$0.49633		

Line No.	Monthly Consumption (therms)	Revenue at Present Rates	Revenue at Proposed Rates	Revenue Change Amount	Revenue Change Percent
4	0	$0.00	$300.00	$300.00	
5	500	$309.71	$606.76	$297.05	95.91%
6	1,000	$619.42	$913.52	$294.10	47.48%
7	1,500	$929.13	$1,220.28	$291.15	31.34%
8	2,000	$1,238.84	$1,527.04	$288.20	23.26%
9	2,500	$1,548.55	$1,833.80	$285.25	18.42%
10	3,000	$1,858.26	$2,140.56	$282.30	15.19%
11	3,500	$2,167.97	$2,447.32	$279.35	12.89%
12	4,000	$2,477.68	$2,754.08	$276.40	11.16%
13	4,500	$2,787.39	$3,060.84	$273.45	9.81%
14	5,000	$3,097.10	$3,367.60	$270.50	8.73%
15	6,000	$3,716.52	$3,981.12	$264.60	7.12%
16	7,000	$4,335.94	$4,594.64	$258.70	5.97%
17	8,000	$4,955.36	$5,208.16	$252.80	5.10%
18	9,000	$5,574.78	$5,821.68	$246.90	4.43%
19	10,000	$6,194.20	$6,435.20	$241.00	3.89%
20	11,000	$6,813.62	$7,048.72	$235.10	3.45%
21	12,000	$7,433.04	$7,662.24	$229.20	3.08%
22	13,000	$8,052.46	$8,275.76	$223.30	2.77%
23	14,000	$8,671.88	$8,889.28	$217.40	2.51%
24	15,000	$9,291.30	$9,502.80	$211.50	2.28%
25	17,500	$10,839.85	$11,036.60	$196.75	1.82%
26	20,000	$12,388.40	$12,570.40	$182.00	1.47%
27	22,500	$13,936.95	$14,104.20	$167.25	1.20%
28	25,000	$15,485.50	$15,638.00	$152.50	0.98%
29	30,000	$18,582.60	$18,705.60	$123.00	0.66%
30	35,000	$21,679.70	$21,773.20	$93.50	0.43%
31	40,000	$24,776.80	$24,840.80	$64.00	0.26%
32	45,000	$27,873.90	$27,908.40	$34.50	0.12%
33	50,000	$30,971.00	$30,976.00	$5.00	0.02%
34	60,000	$37,165.20	$37,111.20	-$54.00	-0.15%
35	70,000	$43,359.40	$43,246.40	-$113.00	-0.26%
36	80,000	$49,553.60	$49,381.60	-$172.00	-0.35%
37	90,000	$55,747.80	$55,516.80	-$231.00	-0.41%
38	100,000	$61,942.00	$61,652.00	-$290.00	-0.47%
39	125,000	$77,427.50	$76,990.00	-$437.50	-0.57%
40	150,000	$92,913.00	$92,328.00	-$585.00	-0.63%
41	175,000	$108,398.50	$107,666.00	-$732.50	-0.68%
42	200,000	$123,884.00	$123,004.00	-$880.00	-0.71%
43	225,000	$139,369.50	$138,342.00	-$1,027.50	-0.74%
44	250,000	$154,855.00	$153,680.00	-$1,175.00	-0.76%

CNGC/309
Amen

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

RONALD J. AMEN
Exhibit No. 309

Ronald J. Amen Statement of Qualifications

Ronald J. Amen

Mr. Amen has over 37 years of combined experience in utility management and consulting in the areas of regulatory support, resource planning, organizational development, distribution operations and customer service, marketing and sales, and systems administration. He has particular expertise in the following areas: regulatory policy, strategy and analysis; resource strategy, planning and financial analysis; cost allocation and pricing issues; business process design and organizational structures; and expert witness testimony. Prior to joining Black & Veatch, Mr. Amen's consulting experience included Concentric Energy Advisors, Inc. and Navigant Consulting, Inc. His prior utility experience includes Manager of Federal Regulatory Affairs at Puget Sound Energy, Inc., Director of Rates at Washington Natural Gas Company, Regional Director - Operations and Director – Rates for Indiana Energy (now Vectren), and management positions in Information Systems and Distribution Operations at Ohio Valley Gas Corporation.

DIRECTOR

Specialization:
Financial analysis, regulatory support, strategy, operations, litigation support

Office Location
Redmond, Washington

Education
- B.S., Business Administration (Finance and Economics), College of Business Administration, University of Nebraska, 1978

Professional Associations
- American Gas Association
- Southern Gas Association

Year Career Started
1978

Year Started with B&V
2013

PROJECT EXPERIENCE

REGULATORY POLICY, STRATEGY AND ANALYSIS

Confidential Financial / Energy Partners (2015)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Confidential International Energy Company (2014)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Pacific Gas & Electric Company (2014)

Developed an extensive industrywide benchmarking study to determine the cost allocation and ratemaking treatment utilized by Local Distribution Companies (LDCs) in the United States for recovery of gas transmission costs. Benchmarked cost allocation and rate design utilized by Interstate/Intrastate Pipelines. Benchmarked how Industrial & Electric Generation customers are served with natural gas.

Public Service Company of New Mexico (2009-2010)

Provided case management, revenue requirement, cost of service and rate design support for general rate cases in the utility's two state regulatory jurisdictions. Issue management and policy development included an electric fuel and purchased power cost mechanism, recovery of environmental remediation costs for a coal fired power plant, and the valuation of renewable energy credits related to a wind power facility.

Confidential International Energy Company (2009)

Provided due diligence on behalf of client related to the purchase of a gas/electric utility, including a review of the regulatory and market-related assumptions underlying the client's valuation model, resulting in the validation of the model and identification of key business risks and opportunities.

Confidential Energy Company (2007)

Provided regulatory due diligence support for client related to a proposed merger with a multijurisdictional gas/electric company including an evaluation of the regulatory landscape in the various applicable state jurisdictions, recent regulatory decisions, and current regulatory issues.

Public Service Electric & Gas (2004)

Provided management with an evaluation of its line extension practices for both its gas and electric services and an earnings impact assessment using a proprietary evaluation model. Conducted a workshop for management on the results of the evaluation and recommendations for consideration in the areas of revenue enhancements, modification of internal policies and procedures, and construction cost control areas.

Washington Gas Light (2004)

Provided management with an evaluation of the policies, procedures and tools presently used in its new customer addition process, an assessment of the impact of new customer growth on net operating income, and regulatory solutions to accelerate recovery of new customer costs that best meet the regulatory requirements of its three state jurisdictions.

Confidential Energy Company (2003)

Performed due diligence on behalf of a confidential energy company client related to the acquisition of a U.S. interstate pipeline, involving a market assessment related to its customer contracts and their prospective alternatives.

Terasen Gas (now FortisBC) (2002 – 2003)

Engaged to assist with the development of a gas transmission asset ownership strategy. The project included researching examples from other jurisdictions in North America for transmission ownership structures, the supporting rationale and the resulting regulatory treatment.

Chesapeake Utilities (2001 – 2002)

Provided expert witness testimony on the subject of new area expansion programs in the United States for the client's general rate case proceeding in Delaware. As part of a negotiated settlement of the case, the client was permitted to establish a new area expansion pilot program.

Puget Sound Energy (1997, 2001)

Redesigned gas line extension policy based on financial investment criteria, standardized construction costs, and revenue contributions derived from the client's residential end-use data (building type/size/vintage, appliance type, etc.). Introduced a new customer rate option for customers whose facilities extensions did not meet the target rate of return requirement, which significantly reduced earnings attrition caused by rapid customer growth. In a later general rate proceeding, testimony support was provided regarding the modifications and revisions to the facilities extension program.

RESOURCE PLANNING, STRATEGY AND FINANCIAL ANALYSIS

Fortis BC (2011)

Retained to help develop a gas supply incentive mechanism in cooperation with the British Columbia Utilities Commission staff and the company's other stakeholders. Provided an independent analysis of the utility's management of pipeline and storage capacity and supply. Part of this work entailed a review of the major markets in which the utility transacted, reviewing the size of trading activity at the major market hubs and reviewing the price indices for these markets.

Black Hills Colorado Electric Utility (2009)

Engaged as a member of a consultant team that served as the independent evaluator in a competitive solicitation for non-intermittent generation resources. Jointly recommended by the utility client, the staff of the utility commission and the state attorney general, the consulting team acted as an agent of the public utility commission monitoring and overseeing the solicitation, which included reviewing the request for proposals and solicitation process, including provisions of the power purchase agreement, preliminary review (economic and contractual) of bids received from the request for proposals, initial modeling of bids for screening, selection of bidders with whom to conduct negotiations and oversight of the negotiation process, and the ultimate selection of the winning bid. Provided due diligence review of all input data, preliminary and final model output, and output summaries. The team produced biweekly confidential reports to the commission regarding the process and its results.

NW Natural (2007-2008)

Assisted with the development of its long-term Integrated Resource Plan (IRP) for its Oregon and Washington service territories. The IRP included the evaluation of incremental inter- and intra-state pipeline capacity, underground storage, and two proposed LNG plants under development in the region.

Puget Sound Energy (2007)

Engaged to assist the client with the development of a natural gas resource efficiency and direct end-use strategy, an interdepartmental initiative focused on preparing a natural gas resource efficiency plan that optimizes customers' end-use energy consumption while furthering corporate customer, financial, environmental, and social responsibilities.

Avista Utilities (2005)

As part of a review of a gas procurement strategy and hedging analytics, provided gas local distribution company (LDC) case studies for gas procurement and risk management practices, including identification of risk management best practices across the industry.

Puget Sound Energy (2003)

Provided resource planning strategy and analysis for the company's Least Cost Plan, including a review of the company's underlying 20-year electric and gas demand forecasts.

Puget Sound Energy (2002 – 2003)

Engaged as a member of a consulting team serving as the client's financial advisor for the acquisition of new electric power supply resources. Conducted a multitrack solicitation process for and evaluation of generation assets and purchase power agreements. Provided regulatory support for the acquisition in a subsequent power cost rate proceeding.

Central Illinois Light Company (Ameren Utilities) (2002 – 2003)

Provided an evaluation of the functions provided by the utility's underground storage facilities for the purpose of assigning cost responsibility to the various customer groups, which had been challenged by parties in the company's general rate proceeding.

Confidential European Electric Utility (1999)

Provided strategy and analysis support, including a review of the natural gas value chain in the United States, as part of an overall project scope focusing on the evaluation of retail multi-energy strategies for the client.

Austin Energy (1997 – 1998)

Engaged as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process.

COST ALLOCATION, PRICING ISSUES AND RATE DESIGN

Cascade Natural Gas Corporation (2015 - 2016)

Provided cost of service and rate design support for the company's general rate case filings in its two state jurisdictions, Oregon and Washington. Conducted a Long-run Incremental Cost Study in the Oregon jurisdiction and an embedded class allocated cost of service study in the Washington jurisdiction. Performed benchmark analyses to compare each of the client's administrative and general

(A&G) and operations and management (O&M) expenses, on a per-customer basis, to various peer groups. Analyses were performed for natural gas utilities and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations.

Chesapeake Utilities (2015 – 2016)

For its Delaware jurisdiction, provided cost of service and rate design support in the client's general rate case proceeding, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism.

Homer Electric Association / Alaska Electric and Energy Cooperatives (2015)

Represented clients in an ENSTAR gas general rate proceeding. Testimony discuss accepted industry principles of revenue allocation and rate design, including the applicability to and alignment with ENSTAR's revenue allocation and rate design proposals for large power and industrial customers. Provided a critique of certain methodological aspects of ENSTAR's Cost of Service study, proposed revenue allocation, and rate design relating to the various large power and industrial customers.

Arkansas Oklahoma Gas Corporation (2002, 2003, 2004, 2007, 2012, 2013)

Provided cost of service and rate design support for several of the company's general rate case filings in its two state jurisdictions and in support of Section 311 transportation filings (2007, 2010) before the Federal Energy Regulatory Commission. Provided related research, design and expert witness testimony in support of a Revenue Decoupling mechanism in one jurisdiction and a Weather Normalization Adjustment mechanism in the other jurisdiction, along with a significant increase in fixed charges and the introduction of demand charges for the company's largest customer classes. Conducted a pre-filing "decoupling" workshop for the utility commission staff.

Northern Indiana Public Service Company (NiSource) (2009 – 2010, 2013)

Conducted class allocated cost of service studies for the client's natural gas (including two other affiliate gas utilities) and electric operations. Work included reconfiguring the Company's commercial and industrial customer classes according to size of load and customer-related facilities. Rate design was modernized to recover a greater portion of fixed costs via fixed monthly customer and demand based charges, a transition to a "Straight-Fixed Variable" form of rate design. Industry research was provided on alternative rate designs for the electric service, including Time-of-Use rates and Critical Peak Pricing. Served as an expert witness on behalf of the client in three general rate cases before the Indiana Utility Regulatory Commission.

Southwestern Public Service Company (Xcel) (2012)

Retained to conduct a study to estimate the conservation effect of replacing its existing electric residential rate design with an alternative rate design such as an inverted block rate design. Reviewed inclining block rate structures that have actively been employed in other jurisdictions and also reviewed technical and academic literature to assess the elasticity of electricity demand for residential customers in the southwestern U.S. Analyzed 2009-2011 residential data to determine what sort of conservation effect the company may expect by implementing an inclining block rate structure. Provided an overview of alternative rate structures which may also promote conservation effects, such as seasonal rates, three-part rates and time-of-use (TOU) rates, and considered the competing incentives of promoting conservation and cost recovery, without specific rate mechanisms to address this conflict.

Atlantic Wallboard LP and Flakeboard Company Limited (JD Irving) (2012)

Represented clients in an Enbridge Gas New Brunswick Limited Partnership ("EGNB") general rate proceeding. Testimony responded to the 2012 allocated cost of service study and rate design that was submitted to the New Brunswick Energy and Utilities Board by EGNB. Testimony also provided benchmark information regarding EGNB's distribution pipeline infrastructure in New Brunswick. Canada.

Western Massachusetts Electric Company (Northeast Utilities) (2010 – 2011)

Supported utility in its decoupling proposal for the company's general rate case. Work included: 1) research on the financial implications of decoupling; 2) identification of decoupling mechanism details to address company and regulatory requirements and objectives; 3) identification of rate adjustment mechanisms that would work together with the company's proposed decoupling mechanism; and 4) preparing pre-filed testimony and testifying at hearings in support of the company's decoupling and rate adjustment proposals. The proposed rate adjustment mechanisms included an inflation adjustment mechanism based on a statistical analysis, and a capital spending mechanism to recover the costs associated with capital plant investment targeted to improving service reliability.

Interstate Power & Light (Alliant Energy) (2010 – 2011)

Conducted class allocated cost of service studies for a Midwestern electric utility's Minnesota electric operations. Work included reconfiguring the company's customer classes for cost of service purposes to collapse end-use based classes with the classes to which they would be eligible. Cost of service studies were performed on a before-and-after basis for the existing and proposed classes. The cost of service studies included a fixed/variable study for production costs, and a primary/secondary study for poles, transformers and conductors. Performed a TOU analysis to determine the appropriate rate differentials for its peak and off-peak rates. Served as an expert witness on behalf of the client in a general rate case before the Minnesota Public Service Commission.

National Grid (2010)

Conducted class allocated cost of service studies for the client's Massachusetts natural gas operations. This task included combined gas cost of service studies for the consolidation of four gas service territories into two gas utility subsidiaries. During interrogatories, performed four separate allocated cost of service studies for each gas service territory. Work included reconfiguring the company's commercial and industrial customer classes according to size of load and customer-related facilities. Served as an expert witness on behalf of the client in consolidated general rate cases before the Massachusetts Department of Public Utilities.

NW Natural (2008)

Provided cost of service and rate design support for the utility's Washington general rate case, including expert witness testimony. Assisted the client with an earlier revenue neutral reconfiguration of its Oregon commercial/industrial sales and transportation service offerings. The earlier initiative included collaborative work with an industrial customer stakeholder group.

Integrys Energy (2007)

Assisted the client with the pursuit of alternative regulatory initiatives in conjunction with company's expansion of its energy efficiency and conservation programs. Supported the research, design, and selection of revenue decoupling mechanisms for its two Illinois regulated gas utility subsidiaries, Peoples Gas Light & Coke Utility and North Shore Gas Company. Served as the cost of service witness in two general rate case filings.

Puget Sound Energy (2001 – 2002, 2006 – 2007)

In two Washington general rate proceedings, provided cost of service and rate design support, including expert witness testimony in support of the utility's proposed gas revenue decoupling mechanism. Conducted research on accelerated cost recovery mechanisms for infrastructure replacement, electric power cost adjustment mechanisms and gas supply pricing options of utilities in North America.

Southern Union Company (2006, 2007)

Engagement director for cost of service and rate design support for the general rate proceedings of the company's Midwestern (Missouri Gas Energy) and northeastern Pennsylvania (PG Energy) gas utilities, including expert witness testimony on cost of service, rate design and declining use-per-customer. Rate design support included a proposed 10-year weather normal, and the introduction of straight-fixed variable rates (Midwestern LDC). This was the third consecutive rate case engagement for the Northeastern LDC.

Vectren Energy Delivery Ohio (2004 – 2005)

Assisted the company with the preparation of a retail customer choice filing for one of its gas distribution jurisdictions. Provided support for the development ancillary service costs, the design of program cost recovery mechanisms, and tariff structure for service offerings.

Connecticut Natural Gas (1999 – 2000, 2002 – 2003, 2005)

Served as engagement manager for cost of service and rate design support, including expert witness testimony, for the client's participation in a statewide gas unbundling proceeding. Subsequent projects included analysis of the client's demand forecasting capability, implementation of an algorithm-based balancing service and a cost of service studies related to transportation-related administrative costs, resources supporting system reliability and recovery of potentially stranded costs.

Sempra Energy (2001 – 2002)

Provided case strategy and cost of service support for the biennial cost allocation proceedings of its two utility subsidiaries, Southern California Gas and San Diego Gas & Electric.

BC Gas Utility Ltd. (now FortisBC) (2000 – 2001)

Served as engagement manager for cost of service and rate design support. Represented the client in its capital investment recovery proceeding for a major pipeline project, a cross-provincial (British Columbia) transmission pipeline. The three-phase project included regulatory strategy support for executive management regarding the integration of the pipeline proposal with the utility's Performance Based Ratemaking and unbundling initiatives and a global rate design proceeding. Cost of service support included a review of its gas cost portfolio allocation to firm sales customer classes, a survey of the trends in gas cost allocations and incentive mechanisms in North America, and serving as a facilitator for an all-party cost allocation and rate design workshop.

Oklahoma Natural Gas Company (ONEOK) (1999 – 2000)

Served as engagement manager for cost of service and rate design support, including expert witness testimony, for client's asset separation and unbundling proceeding as well as a subsequent general rate case. Integrated gas utility (wellhead to burner-tip) unbundled upstream services (production and gathering, storage, and intra-state transmission) from its distribution business.

Confidential South American Gas Utility (1999)

For an affiliate of a major U.S. energy company, conducted a cost of service and rate design training for management personnel engaged in the planned restructuring of the rate-setting processes for three gas utilities in Brazil.

Confidential Canadian Energy Marketer (1999)

Provided consulting support and position paper on cost allocation and pricing issues for Canadian gas marketer's participation in a restructuring collaborative sponsored by the intra-provincial pipeline and local distribution utility in Saskatchewan.

Washington Natural Gas (1995)

Negotiated and obtained regulatory approval of a 20-year contract with the company's largest industrial customer, which avoided bypass of 14 primary plant facilities within the service territory, prevented loss of annual throughput, and maintained contribution to system costs.

Washington Natural Gas (1995)

Obtained regulatory approval of unbundled, cost-based transportation services to meet large commercial and industrial customer needs and redesigned rates of other classes to better align with new cost of service methodology. The project required the facilitation of a collaborative working group of key industrial customers, customer associations, commission staff, and consumer advocacy agencies.

UTILITY SYSTEM OPERATIONS AND ORGANIZATIONAL DEVELOPMENT

Puget Sound Energy (2013 – 2014)

Engaged to perform a review of its project management and capital spending authorization processes (CSA). The overall project objectives were to educate project management (PM) staff as to the importance and relevance of regulatory prudence standards, evaluate existing PM processes along with newly introduced corporate CSA processes, and propose PM and corporate process and documentation efficiencies. This task was accomplished through 1) a situational assessment and risk review; 2) analysis of project management practices; and 3) development of common documentation for the CSA and PM processes.

Puget Sound Energy (2012 – 2013)

Engaged to perform a review of how the company compares to similarly-situated utilities in the areas of the underlying capitalized costs related to new customer additions ("new business investment") and the management policies and practices that influence the new business capital investment. Examined the interrelationships of our client's management policies and practices in the functional areas related to new business investment and developed an understanding of the nature of the costs captured by the new business investment process. Benchmarked those costs relative to peers' cost factors and management capital expenditure practices and performed targeted peer group interviews on our client's behalf. The review identified certain trends and/or interrelationships between management policies and practices, as well as other exogenous factors, and the resulting impact on new business investment.

Puget Sound Energy (2011 – 2012)

Engaged to perform a review of its electric transmission planning and project prioritization process. The emphasis of the review was to determine if the process implemented by the client could be expected to meet the regulatory standard of prudence, as adopted by the state regulatory commission. Reviewed the prudence standard adopted by the commission in several recent regulatory proceedings, supplemented by our knowledge of the prudence standard adopted at a national level and in other states. The engagement included two phases: 1) an initial situation assessment of the existing process employed by the client, and 2) a review of the historic implementation of that process by reviewing a sampling of transmission projects. Compiled and provided examples of capital planning documents and procedures, viewed as "best practices," from other electric utilities and other relevant transmission entities.

Alliant Energy (2011 – 2012)

Provided audit support for one of the company's gas and electric utilities, Interstate Power & Light, during a management audit ordered by one of its two regulatory jurisdictions. Conducted a pre-audit of distribution operations and resource planning processes to provide the client with potential audit issues. Assisted the client throughout the audit process in responding to information requests, preparing company executives and management personnel for audit interviews, and management of preliminary audit issues and findings by the independent audit firm.

Ameren Illinois Utilities (2009 – 2010)

Performed a number of benchmark analyses to compare each of the client's A&G and O&M expenses, on a per-customer basis, to various peer groups conducted for the client's natural gas and electric operations. Analyses were performed for natural gas, electric and combination utilities with both electric and gas operations. Various iterations of the analyses were prepared to make the peer group of utilities more comparable to the characteristics of the client's utility operations. Served as an expert witness on behalf of the client in a consolidated general rate case proceeding of its three utility subsidiaries before the Illinois Commerce Commission.

California Water Service Company (2007 – 2008)

Engaged to manage the implementation of a new revenue decoupling mechanism into its 24 separate rate areas. Changes to the following processes and related procedures were required: rate setting, meter reading, billing, revenue and financial reporting. Microsoft Project was used to manage and track the implementation throughout the following organizations: Rates, Accounting, Information systems, Communications, and Customer Service.

Puget Sound Energy (2007)

Conducted an evaluation of the company's key accounts (Top 100) and business account services organization. Work included compilation of "best practices" from peer group utilities, recommendations related to staffing levels, roles and responsibilities, and the interrelationships with the customer service (call center), revenue management and community relations organizations of the utility.

Washington Gas Light (2006)

Provided market monitoring strategies and action plans based on an analysis of competitive threats and discussions with the client's customers and other utilities facing similar issues. Intent of recommended monitoring strategies and corresponding action plans to result in increased customer growth (meters) and/or customer retention, including a prioritized implementation approach to the monitoring strategies and action plans, based on benefits to the client and time to implement.

Entergy New Orleans / Entergy Gulf States (2004 – 2005)

Conducted an evaluation of the two gas operating subsidiaries' capital planning, asset management strategy, and customer growth practices. Formulated a strategy for improving the profitability of the entities, with regulatory strategies for its two jurisdictions that included a special cost recovery mechanism for accelerated infrastructure replacement programs.

Austin Energy (1997 – 1998)

Engaged as a member of three-consultant team that established a self-sustaining energy services business to replace its rebate-based, demand-side management programs. Area of focus included the finance and administrative functions as well as the employee evaluation and recruitment process, which involved establishing the organization structure, span of control, job descriptions, qualifications, and salary ranges. The team worked closely with the head of the new organization, the municipal utility management, and the relevant municipal government agencies. Also facilitated numerous management and stakeholder meetings.

TXU Energy (1997)

Provided research and consulting support to establish performance metrics and benchmarks from peer group companies for the client's performance management system.

EXPERT WITNESS TESTIMONY PRESENTATION

- Alaska Regulatory Commission
- Arkansas Public Service Commission
- British Columbia Utility Commission (Canada)
- Connecticut Department of Public Utility Control
- Delaware Public Service Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Massachusetts Department of Utilities
- Minnesota Public Utilities Commission
- Missouri Public Service Commission
- New Brunswick Energy and Utilities Board (Canada)
- Oklahoma Corporation Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission
- Federal Energy Regulatory Commission

PROFESSIONAL HISTORY

Black & Veatch (Present)

Director

Concentric Energy Advisors, Inc. (2007 – 2013)

Vice President

Navigant Consulting, Inc. (1997 – 2007)

Director

Puget Sound Energy, Inc. (1997)

Manager – Federal Regulatory Affairs

Washington Natural Gas Company (1993 – 1997)

(Merged with Puget Power & Light to form Puget Sound Energy in 1997)
Director – Rates and Tariffs

Indiana Energy (now Vectren) (1984 – 1993)

Regional Director – Distribution Operations
Director – Rates

Ohio Valley Gas Corporation (1978 – 1984)

Data Processing Manager
Assistant District Manager – Distribution Operations

SELECTED PUBLICATIONS/PRESENTATIONS

"Enhancing the Profitability of Growth," American Gas Association, Rate and Regulatory Issues Seminar, April 4 - 7, 2004

"Regulatory Treatment of New Generation Resource Acquisition: Key Aspects of Resource Policy, Procurement and New Resource Acquisition," Law Seminars International, Managing the Modern Utility Rate Case, February 17 - 18, 2005

"Managing Regulatory Risk – The Risk Associated with Uncertain Regulatory Outcomes," Western Energy Institute, Spring Energy Management Meeting, May 18 - 20, 2005

"Capital Asset Optimization – An Integrated Approach to Optimizing Utilization and Return on Utility Assets," Southern Gas Association, July 18 - 20, 2005

"Resource Planning as a Cost Recovery Tool," Law Seminars International, Utility Rate Case Issues & Strategies, February 22 - 23, 2007

"Natural Gas Infrastructure Development and Regulatory Challenges," Southeastern Association of Regulatory Utility Commissioners, Annual Conference, June 4 – 6, 2007

"Resource Planning in a Changing Regulatory Environment," Law Seminars International, Utility Rate Cases – Current Issues & Strategies, February 7 - 8, 2008

"Natural Gas Distribution Infrastructure Replacement," American Gas Association, Rate Committee Meeting and Regulatory Issues Seminar, April 11 – 13, 2010

"Building a T&D Investment Program to Satisfy Customers, Regulators and Shareholders," SNL Webinar, March 27, 2014

"Utility Infrastructure Replacement; Trends in Aging Infrastructure, Replacement Programs and Rate Treatment," Large Public Power Council, Rates Committee Meeting, August 14, 2014

CNGC/400
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

DIRECT TESTIMONY OF PAMELA J. ARCHER
REPRESENTING CASCADE NATURAL GAS CORPORATION

Revenue Proof / Tariffs

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I. INTRODUCTION

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

A. My name is Pamela J. Archer and my business address is 8113 W. Grandridge Blvd., Kennewick, WA 99336. My present position is Supervisor, Regulatory Analysis for Cascade Natural Gas Corporation (Cascade or Company), a wholly-owned subsidiary of MDU Resources Group, Inc. (MDU Resources).

Q. Would you briefly describe your duties?

A. Yes. I supervise the preparation of regulatory reports and rate/tariff filings for regulatory approval, as well as provide regulatory and tariff advice and information to others within the Company.

Q. Please briefly describe your educational background and professional experience.

A. I am a 1992 graduate of The Ohio State University with a B.S. in Chemical Engineering. In 1996, I graduated from Ashland University with a Master of Business Administration Degree. Prior to joining Cascade in September 2010, I was employed as an Energy Specialist at the Office of the Ohio Consumers' Counsel for fifteen years. I have received additional training at the Annual Regulatory Studies Program sponsored by the National Association of Regulatory Utility Commissioners (NARUC) at Michigan State University in 1993 as well as at multiple events sponsored by NARUC and the National Association of State Utility Consumer Advocates. I have also taken post-graduate courses in Managerial Accounting, Corporate Finance, and Business Law at The Ohio State University.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is threefold:

- First, I describe the revenue proof shown in Exhibit CNG/401;

- Second, I present the Company's new tariff P.U.C. OR. No. 10 (New Tariff) provided in Exhibit CNG/402, which, upon approval in this general rate case filing, will replace in its entirety the Company's current Tariff, P.U.C. Or. No. 9 (Current Tariff). This testimony includes a description of how the New Tariff differs from the Current Tariff, and Exhibit CNG/403 provides a cross-walk from the Current Tariff to the New Tariff and a brief description of changes in the New Tariff; and
- Third, I describe changes and additions to the New Tariff that relate directly to issues proposed in this general rate case filing through the testimony of other witnesses.

II. REVENUE PROOF

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

A. Yes. The revenue proof shows the presentation of revenue at current rates and current volumes. The amount shown for current rates includes all the components of the rates, including gas costs, taxes, the public purpose charge and any billing adjustments for each rate schedule. The present billing section matches the amount of 2015 base year revenue which appears on the income statement.

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 volumes and forecasted billing determinants.

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

A. The forecasted volumes and forecasted billing determinants used in this revenue proof come from the most recent IRP forecast.

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

A. Yes. The use of these forecasted amounts forms the basis of an adjustment to the revenue requirement which is addressed further in Company witness Michael Parvinen's testimony.

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

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

III. NEW TARIFF, P.U.C. OR. NO. 10

Q. Why is the Company replacing its Current Tariff in its entirety?

A. The Company is replacing its current Oregon tariff, P.U.C. Or. No. 9 (Current Tariff), which was last updated in 2007, in its entirety in order to make necessary formatting and housekeeping changes. The new tariff will be designated as P.U.C. OR. No. 10 (New Tariff).

Q. Please provide an overview of the formatting changes in the New Tariff.

A. The New Tariff includes the following formatting changes:

- The headers and footers of the New Tariff sheets are reformatted to reflect that the Public Utility Commission of Oregon (Commission) no longer needs space in the upper right hand corner of each sheet to stamp the receipt of a tariff sheet. The issuing Company officer's name has also been removed from the footer as this is no longer required content.
- The content of the New Tariff is no longer presented in text boxes which allows for more efficient use of space on the page and for more effective editing.

- The New Tariff sheets are renumbered so the tariff sheet numbering is consistent with the numbering of the corresponding rule or rate schedule.
- In the New Tariff, definitions are provided in Rule 2 so that they are readily accessible and defined before they are used in the substance of the New Tariff.
- The content in Current Tariff, Rule 1 “Applications and Contracts for Service” and Current Tariff, Rule 2 “Customer Deposits” has been reorganized in the New Tariff as Rule 3 “Establishing Service” and Rule 4 “Customer Deposits” such that requirements for establishing service are not comingled with the requirements related to deposits.
- Proposed Rule 5 “Discontinuation of Service,” is written to remove amounts for fees associated with discontinuation of service. The rules are intended to define terms and conditions while the schedules define the rates. It is administratively more efficient to have the amount charged for fees stated only in Schedule 200 so that a reference is not missed whenever the charge is updated.
- Generally, all rate schedules are reformatted for consistency and to remove references to those schedules that are no longer in effect.

Q. Is the Company proposing any changes to language in the New Tariff?

A. Yes. The Company has made numerous language changes for the purpose of clarification and this testimony will address the substantive language changes.

Q. Please describe the substantive language changes made to the rules in the New Tariff.

A. The Company made the following revisions to the rules:

- In New Tariff, Rule 2 “Definitions” (Current Tariff, Rule 15), Cascade added, removed, and revised defined terms for improved clarity.

- Cascade renumbered Rule 3 “Discontinuation of Service” in the Current Tariff as Rule 5 in the New Tariff, and revised the text of the rule so that the grounds for disconnecting service are consistent with the list of reasons for disconnecting service in OAR 860-021-0305.
- Cascade renamed the “Disconnect Visit Charge” in Current Tariff, Rule 3 as the “Field Visit Charge” in New Tariff Rule 5 and Schedule 200. The purpose of this change is to clarify that the fee is not incurred when service is disconnected. The Field Visit Charge is applied only when the Company is unable to either disconnect or reconnect service as planned.
- New Tariff, Rule 6 “Billing” updates the information found in Current Tariff, Rule 4 so that the practices for correcting under- and overbillings are consistent with the changes to OAR 860-021-0135 adopted in Commission Order No. 14-230.[1]
- Cascade renamed the “Returned Check Charge” in Current Tariff, Rule 4 as the “Returned Payment Fee” in New Tariff, Rule 6. The fee is applied to any payment type where funds are insufficient, and the revised name clarifies that the fee applies to all payment types and not only checks.
- Cascade revised Rule 5 of the Current Tariff (renumbered as Rule 7 in the New Tariff) to remove the language that disallowed sharing or reselling of gas. The revision was made for consistency with ORS Chapter 90, which allows landlord/tenant utility billing arrangements.
- Cascade added new language to New Tariff, Rule 7 to clarify that the Company is not required to provide submetering or any services related to submetering, as submetering is an activity on the customer-owned side of the meter.

[1] *In the Matter of Amendments to Rules Regarding Adjustment of Utility Bills*, Docket AR 579, Order No. 14-230 (June 24, 2014).

- Cascade updated its address in New Tariff, Rule 8 “Meter Testing” (Current Tariff, Rule 6).
- Cascade removed the language regarding excess flow valves in Current Tariff, Rule 7 “Service Line Installations” (New Tariff, Rule 9) because this language is repeated in Schedule 200, where it is retained.
- Current Tariff, Rule 17 “Firm Service Priority” is renamed “Order of Priority for Gas Service” in the New Tariff. Additionally, Cascade developed new language in New Tariff, Rule 17 that more broadly addresses the order of service for both core and non-core customers as well as curtailment procedures. Cascade removed the language related to the entitlement period as it only applies to transportation customers.
- Cascade simplified and updated New Tariff, Rule 18 “Limitation of Firm Natural Gas Service” (Current Tariff, Rule 18) by removing outdated references to gas shortages and the Federal Power Commission.

Q. Can you please describe the substantive language changes made to the Schedules in the New Tariff?

A. The Company made the following edits to the Schedules:

- An order referenced in New Tariff, Schedule 100 “Adjustment for Municipal Exactions” (Current Tariff, Schedule No. 100) is removed and replaced with the appropriate Oregon Administrative Rule, OAR 860-022-0040(1).
- Current Tariff, Schedule Nos. 163 and 183 describe services that must be taken together and no other service combinations are available. Current Tariff, Schedule No. 163 is for transportation of customer-owned gas and Current Tariff, Schedule No. 183 establishes the rules associated with the customer-owned gas being delivered in Schedule No. 163. Current Tariff, Schedule Nos. 163 and 183 are

combined in the New Tariff into Schedule 163 for the distribution service of customer-owned gas. Cascade revised and reformatted the information included in Current Tariff, Schedule No. 183 (New Tariff Schedule 163) to clarify its meaning.

- All rate schedules (Schedules 101, 104, 105, 111, 112, 126, 163, and 170) are revised in New Tariff in the following manner:
  - Cascade removed language regarding meter configurations from the Availability sections as this is more appropriately addressed in New Tariff, Rule 7 “Meters.”
  - Cascade removed the language prohibiting the submetering and reselling of natural gas. Submetering is a customer decision and a landlord may resell gas under ORS Chapter 90.
  - Cascade added or moved a term under the heading “General Terms” to state that service under the rate schedule broadly includes compliance to all approved and appropriate rules and regulations.

Q. Is the Company proposing any changes to rates or charges?

A. Yes. The Company is updating the tax component for customer-provided construction funds in New Tariff, Rule 9 “Service Line Installations” (Current Tariff, Rule 7) and New Tariff, Rule 10 “Main Installations” (Current Tariff, Rule 8). This percentage amount is automatically applied to customer contributions for service line extensions. A calculation is provided as Exhibit CNG/404 to demonstrate how this rate was reduced from the current amount of 26.56% to the new amount of 20.38%. The Company will update the rate in its final compliance filing that will be submitted after the Commission’s final ruling on this general rate case, ensuring that this amount is based on the most current approved rate of return. All other changes to rates are part of the larger overall case and are discussed in Section IV below.

Q. Are any currently approved tariff sheets removed?

A. Yes.

Q. Which currently approved sheets are being removed and why are they being removed?

A. The Company's New Tariff does not include the following rules and schedules that are in the Current Tariff:

- Cascade has removed Current Tariff, Rule 15 "Definitions" as the pertinent content has been moved to New Tariff, Rule 2.
- Cascade has removed Current Tariff, Rule 16 "Promotional Activities" because it describes promotional activities that are no longer offered.
- Cascade has removed Current Tariff, Schedule No. 145 "Residential Heating Equipment Rental Rate" as this program is no longer available. The Company's energy efficiency programs are now being administered by the Energy Trust of Oregon.
- Cascade has removed Current Tariff, Schedule No. 183 "Optional Customer Owned Gas Supply" because the pertinent content has been consolidated with Current Tariff, Schedule No. 163 "General Distribution System Interruptible Transportation Service" as Schedule 163 in the New Tariff.
- Current Tariff, Schedule No. 175 "Energy Efficiency Investment Recovery Adjustment Provision" was put in place to recover lost margin associated with energy efficiency. This adjustment is no longer needed as the Company has decoupling under Rule 19 "Conservation Alliance Plan Mechanism".
- Cascade has removed Current Tariff, Schedule No. 185 "Optional Firm Pipeline Capacity Supplemental Schedule" because it is a service option that has been frozen since 2007. No customers are taking service on this schedule.

- Cascade has removed Current Tariff, Schedule No. 194 “Temporary Rate Addition”, Current Tariff, Schedule No. 194-A “UM 1283 Merger Rate Credits”, and Current Tariff, Schedule No. 194-B “Other Residual Temporary Adjustment” as these adjustments are no longer in effect.

Q. Did the Company make any other changes to the Tariff you wish to explain?

A. No.

IV. TARIFF CHANGES RELATING TO RATE CASE TESTIMONY

Q. Did you prepare revised tariff sheets to reflect the rate increases and other tariff changes proposed in this case?

A. Yes. Cascade’s revised tariff sheets are provided in Exhibit CNG/402.

Q. Did you rely on data provided by another witness to prepare the tariff sheets?

A. Yes. I relied on the cost-of-service study data, results, and testimony provided by Company witness Ron Amen.

Q. Is the Company proposing any changes to the basic service charge in any of the rate schedules?

A. Yes. The Company is proposing to introduce a monthly basic service charge of $250.00 for Rate Schedule 170. In addition, the monthly basic service charge for Rate Schedule 105 will see an increase from $12.00 to $30.00 while Rate Schedule 163 will see an increase from $500.00 to $750.00.

Q. Does this conclude your direct testimony?

A. Yes it does.

CNGC/401
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

Pamela J. Archer
Exhibit No. 401

Revenue Proof

Cascade Natural Gas Corporation Revenue Proof

Test Year: January 1, 2015 Through December 31, 2015

		Present Billing					Current Rates					Proposed Rates				
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)		Billing Determinants (Therms/Bills)	Rate	Margin	2015 Revenue Adjustment		Percent Distribution	Billing Determinants (Therms/Bills)	Proposed Rate	Proposed Distribution Margin
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)		(G)	(H)	(I)	(I)		(J)	(K)	(L)	(M) (K*L)
Rate 101	**General Residential Service**															
1	**Basic Service Charge**		716,979	$ 3.00		**$ 2,150,937**	**Basic Service Charge**	727,940	$3.00	**$ 2,183,820**	**$ 32,883**	**Basic Service Charge**		727,940	$ 3.00	**$ 2,183,820**
2																
3	Delivery Charge (Jan. - Oct.)			$0.359510			Delivery Charge		$0.36884			Delivery Charge			0.40656	
4	All therms		27,639,162 Therms		27,639,162 Therms	$ 9,936,555	Forecasted Therms	39,969,509		**$ 14,742,354**	**$ 856,950**	Forecasted Therms		39,969,509 Therms		**$ 16,250,004**
5	Delivery Charge (Nov. - Dec.)			$ 0.359510												
6			8 683 243 Therms		8 683 243 Therms	$ 3,121,713										
7	**Total Delivery Charge**		36,322,405 Therms		36,322,405 Therms	**$ 13,058,268**										
8	**Average Cost of Gas**					**19,452,626**										
9	Adjustment					13										
10	Franchise Tax					612,646										
11	PPC and Adjustments					(0)										
12	Public Purpose Fund					641,412										
13	Subtract out PPC Fund & Ajustments					(641,412)										
14	Current Month Unbilled +					25,834,601										
15	Previous Month Unbilled -					(25,327,842)										
16	CAP Adjustment					320,376										
17	Deferrals					704,249										
18	Deficiency					-										
19	**Total Non-Gas Revenue**					2,144,043										
20																
21	**Total Rate Schedule 101 Revenue**					**$ 36,805,874**										
Rate 104	**General Commercial Service**															
22	**Basic Service Charge**		116,921	$ 3.00		**$ 350,763**	**Basic Service Charge**	118,811	$3.00	**$ 356,432**	**$ 5,669**	**Basic Service Charge**		118,811	$ 3.00	**$ 356,432**
23																
24	Delivery Charge (Jan. - Oct.)			0.256550			Delivery Charge		$0.26263			Delivery Charge			$ 0.262630	
25	All therms		19,622,561 Therms		19,622,561 Therms	$ 5,034,168	Forecasted Therms	28,117,840		**$ 7,384,588**	**$ 521,577**	Forecasted Therms		28,117,840 Therms		**$ 7,384,588**
26	Delivery Charge (Nov. - Dec.)			$ 0.256550												
27			5 642 432 Therms		5,642,432 Therms	$ 1,447,566										
28	**Total Delivery Charge**		25,264,993 Therms		25,264,993 Therms	**$ 6,481,734**										
29	Therms Adjustment[1]				-52,467 Therms											
30	**Average Cost of Gas**					**13,523,390.07**										
31																
32	Franchise Tax					390,595.03										
33	PPC and Adjustments					(650.81)										
34	Public Purpose Fund					374,760.85										
35	Adjustment					**(35,386)**										
36	Subtract out PPC Fund & Ajustments					(374,110)										
37	Current Month Unbilled +					16,118,711										
38	Previous Month Unbilled -					(16,024,247)										
39	CAP Adjustment					286,813										
40	Deferrals					534,260										
41	Deficiency					1,201										
42	**Total Non-Gas Revenue**					**$ 1,271,948**										
43																
44	**Total Rate Schedule 104 Revenue**					**$ 21,627,835**										

Cascade Natural Gas Corporation Revenue Proof

Test Year: January 1, 2015 Through December 31, 2015

Line No.	Rate Description (A)	Percent Distribution (B)	Billing Determinants (Therms/Bills) (C)	Rate (D)	Adjusted Billing Determinants (E)	Weather Normalized Revenue (Margin) (F) (D*E)	Current Rates	Billing Determinants (Therms/Bills) (G)	Rate (H)	Margin (I)	2015 Revenue Adjustment (I)	Proposed Rates: Percent Distribution (J)	Billing Determinants (Therms/Bills) (K)	Proposed Rate (L)	Proposed Distribution Margin (M) (K*L)
Rate 105	**General Industrial Service**														
45	**Basic Service Charge**		1,524	$ 12.00		**$ 18,288**	**Basic Service Charge**	1,534	$12.00	**$ 18,414**	**$ 126**	**Basic Service Charge**	1,534	$ 30.00	**$ 46,034**
46															
47	**Total Delivery Charge**		2,571,241 Therms	$ 0.180320	2,571,241 Therms	**$ 463,646**	Delivery Charge		$0.19152			Delivery Charge		$ 0.244580	
48							Forecasted Therms	2,543,274		**$ 487,088**	**$ 23,442**	Forecasted Therms	2,543,274 Therms		**$ 622,034**
49	**Average Cost of Gas**					**1,428,424.33**									
50															
51	Franchise Tax					43,499.87									
52	Adjustment					(25.08)									
53	Deferrals					(500.54)									
54	Deficiency					3,333.77									
55	**Total Non-Gas Revenue**					**46,308.02**									
56															
57	**Total Rate Schedule 105 Revenue**					**$ 1,956,667**									
Rate 111	**Firm Commercial Service**														
58	**Basic Service Charge**						**Basic Service Charge**					**Basic Service Charge**	160	$ 200.00	**$ 32,000**
59															
60	**Total Delivery Charge**		642,155	0.14617		**$ 93,864**	Delivery Charge		$0.15494			Delivery Charge		$ 0.17436	
61							Forecasted Therms	543,756		**$ 84,250**	**$ (9,614)**	Forecasted Therms	543,756		**$ 94,809**
62	**Average Cost of Gas**					**359,178.87**									
63															
64	Franchise Tax					4,624.64									
65	Adjustment					0.00									
66	Deferrals					(123.92)									
67	Deficiency					0.00									
68	**Total Non-Gas Revenue**					**$4,500.72**									
69															
70	**Total Rate Schedule 111 Revenue**					**$ 457,543**									
Rate 111	**Firm Industrial Service**														
71	**Total Delivery Charge**		1,215,006	0.14617		**$ 177,597**	Delivery Charge		$0.15494			Delivery Charge		0.17436	
72							Forecasted Therms	1,021,677		**$ 158,299**	**$ (19,299)**	Forecasted Therms	1,021,677		**$ 178,140**
73	**Average Cost of Gas**					**$ 676,997**									
74															
75	Franchise Tax					$ 8,766									
76	Adjustment					$ -									
77	Deferrals					$ (234)									
78	Deficiency					$ -									
79	**Total Non-Gas Revenue**					**$ 8,532**									
80															
81	**Total Rate Schedule 111 Revenue**					**$ 863,127**									

Test Year: January 1, 2015 Through December 31, 2015

Present Billing

Line No.	Rate Description (A)	Percent Distribution (B)	Billing Determinants (Therms/Bills) (C)	Rate (D)	Adjusted Billing Determinants (E)	Weather Normalized Revenue (Margin) (F) (D*E)
Rate 170	**Interruptible Service**					
82	**Basic Service Charge**					
83						
84	**Total Delivery Charge**		2,478,811	0.12309		**$305,117**
85						
86	**Average Cost of Gas**					**$1,394,575**
87						
88	Franchise Tax					$19,420
89	Adjustment					(4,042.57)
90	Deferrals					(437.50)
91	Deficiency					0.00
92	Previous Month CA1501A -					(1,719,111.62)
93	Current Month CA1501A +					1,690,468.80
94	**Total Non-Gas Revenue**					**(13,702.66)**
95						
96	**Total Rate Schedule 170 Revenue**					**$1,685,988.76**
Rate 163	**Interruptible Transportation**					
97	**Dispatch Service Charge**		348	$ 500.00		**$ 174,000**
98						
99	Commodity Charge Jan - Nov					
100	Commodity Charge First 10,000 Therms		2,776,536 Therms	0.12402	0.00022	$ 344,957
101	Commodity Charge Next 10,000 Therms		2,062,550 Therms	0.11188	0.00022	$ 231,212
102	Commodity Charge Next 30,000 Therms		3,236,912 Therms	0.10512	0.00022	$ 340,976
103	Commodity Charge Next 50,000 Therms		2,678,046 Therms	0.06456	0.00022	$ 173,484
104	Commodity Charge Over 100,000 Therms		6,184,302 Therms	0.03275	0.00022	$ 203,896
105						
106	Commodity Charge Dec					
107	Commodity Charge First 10,000 Therms		267,640 Therms	0.12402	0.00006	$ 33,209
108	Commodity Charge Next 10,000 Therms		222,059 Therms	0.11188	0.00006	$ 24,857
109	Commodity Charge Next 30,000 Therms		377,453 Therms	0.10512	0.00006	$ 39,701
110	Commodity Charge Next 50,000 Therms		249,922 Therms	0.06456	0.00006	$ 16,150
111	Commodity Charge Over 100,000 Therms		442,040 Therms	0.03275	0.00006	$ 14,503
112	**Total Commodity Charge**		18,497,460 Therms			**$ 1,422,945**
113						
114	Franchise Tax					$ 23,028
115	Gross Revenue Fee					$ 34,087
116	Adjustment					$ (479)
117	Previous Month CA1501A -					$ (1,654,060)
118	Current Month CA1501A +					$ 1,645,564
119	Deferrals					$ (6,132)
120	**Total Non-Gas Revenue**					**$ 42,007**
121						
122	**Total Rate Schedule 163 Revenue**					**$ 1,638,952**

Current Rates / Proposed Rates

Line No.	Current Rates	Billing Determinants (Therms/Bills) (G)	Rate (H)	Margin (I)	2015 Revenue Adjustment (I)	Proposed Rates: Percent Distribution (J)	Billing Determinants (Therms/Bills) (K)	Proposed Rate (L)	Proposed Distribution Margin (M) (K*L)
82						**Basic Service Charge**	48	$ 300.00	**$ 14,400**
84	Delivery Charge		$0.12309			Delivery Charge		0.11719	
85	Forecasted Therms	2,439,224		**$300,244**	**$ (4,873)**	Forecasted Therms	2,439,224		**$285,853**
97	**Dispatch Service Charge**	372	$500.00	**$ 186,000**	**$ -**	**Dispatch Service Charg**	372	$ 750.00	**$ 279,000**
99	Commodity Charge					Commodity Charge			
100	Commodity Charge First 10,000 The	3,221,176	0.12402	**$ 399,490**	**$ (8,490)**	Commodity Charg	3,221,176 Therms	0.12909	**$ 415,822**
101	Commodity Charge Next 10,000 The	2,500,576	0.11188	**$ 279,764**	**$ (3,205)**	Commodity Charg	2,500,576 Therms	0.11645	**$ 291,192**
102	Commodity Charge Next 30,000 The	4,413,295	0.10512	**$ 463,926**	**$ 7,414**	Commodity Charg	4,413,295 Therms	0.10941	**$ 482,859**
103	Commodity Charge Next 50,000 The	4,000,770	0.06456	**$ 258,290**	**$ (9,064)**	Commodity Charg	4,000,770 Therms	0.06720	**$ 268,852**
104	Commodity Charge Next 400,000 Th	16,160,944	0.03275	**$ 529,271**	**$ 11,659**	Commodity Charg	16,160,944 Therms	0.03409	**$ 550,927**
105	Commodity Charge Over 500,000 T	2,433,032	0.01755	**$ 42,700**	**$ 5,926**	Commodity Charg	2,433,032 Therms	0.01827	**$ 44,451**

Cascade Natural Gas Corporation Revenue Proof

Test Year: January 1, 2015 Through December 31, 2015

Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)		Billing Determinants (Therms/Bills)	Rate	Margin	2015 Revenue Adjustment	Percent Distribution	Billing Determinants (Therms/Bills)	Proposed Rate	Proposed Distribution Margin
	Present Billing						Current Rates					Proposed Rates			
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)		(G)	(H)	(I)	(I)	(J)	(K)	(L)	(M) (K*L)
Rate 164	**Interruptible Transportation**														
123	Dispatch Service Charge		24	$ 500.00		$ 12,000									
124															
125	Commodity Charge Jan - Nov														
126	Commodity Charge First 10,000 Therms		220,000 Therms	0.12402	0.00022	$27,333									
127	Commodity Charge Next 10,000 Therms		220,000 Therms	0.11188	0.00022	$24,662									
128	Commodity Charge Next 30,000 Therms		660,000 Therms	0.10512	0.00022	$69,524									
129	Commodity Charge Next 50,000 Therms		1,100,000 Therms	0.06456	0.00022	$71,258									
130	Commodity Charge Next 400,000 Therms		8,306,485 Therms	0.03275	0.00022	$273,865									
131	Commodity Charge Over 500,000 Therms		1,905,296 Therms	0.01755	0.00022	$33,857									
132															
133	Commodity Charge Dec														
134	Commodity Charge First 10,000 Therms		20,000 Therms	0.12402	0.00006	$2,482									
135	Commodity Charge Next 10,000 Therms		20,000 Therms	0.11188	0.00006	$2,239									
136	Commodity Charge Next 30,000 Therms		60,000 Therms	0.10512	0.00006	$6,311									
137	Commodity Charge Next 50,000 Therms		100,000 Therms	0.06456	0.00006	$6,462									
138	Commodity Charge Next 400,000 Therms		772,543 Therms	0.03275	0.00006	$25,347									
139	Commodity Charge Over 500,000 Therms		165,644 Therms	0.01755	0.00006	$2,917									
142	**Total Commodity Charge**		**13,549,968 Therms**			**$546,256**									
143															
144	Gross Revenue Fee					$ 11,916									
145	Previous Month CA1501A -					(570,172.41)									
146	Current Month CA1501A +					$ 560,989									
147	**Total Non-Gas Revenue**					**$ 2,733**									
148															
149	**Total Rate Schedule 164 Revenue**					**$ 560,989**									
Rate 902	**Interruptible Transportation**														
150	**Dispatch Service Charge**		12	500		**$6,000**	**Dispatch Service Charge**	12	$500.00	**$6,000**	**$ -**	**Dispatch Service Charg**	12	500	**$6,000**
151															
152	Commodity Charge Jan-Oct		145,853,439 Therms	$0.0015244		$222,338.98	Commodity Charge		$0.0015259			Commodity Charge		$0.0015259	
153	Commodity Charge Nov-Dec		30,579,333 Therms	$0.0015259		$46,661.00	Forecasted Therms	178,932,927		**$273,033.75**	**$ 4,034**	Forecasted Therms	178,932,927 Therms		**$273,034**
154	**Total Commodity Charge**		**176,432,772 Therms**			**$268,999.99**									
155															
156	Contract Demand Charge		10800000		$0.1005555	**$1,085,999.40**	Contract Demand Charge	10,800,000	$0.10056	**$1,085,999.40**	**$0.00**	Contract Demand Cha	10,800,000	$0.1005555	**$1,085,999**
157															
158	Gross Revenue Fee					$29,051									
159	Previous Month CA1501A -					(1,390,049.92)									
160	Current Month CA1501A +					1,400,152.58									
161	**Total Non-Gas Revenue**					**39,153.20**									
162															
163	**Total Rate Schedule 902 Revenue**					**$1,400,152.59**									
Rate 903	**Interruptible Transportation**														
164	**Dispatch Service Charge**		12	500		**$6,000**	**Dispatch Service Charge**	12	$500.00	**$6,000**	**$ -**	**Dispatch Service Charg**	12	500	**$6,000**
165															
166	Commodity Charge Jan-Oct		7,083,567 Therms	0.0116819		$82,750	Commodity Charge		$0.01169			Commodity Charge		0.0116936	
167	Commodity Charge Nov-Dec		1,162,369 Therms	0.0116936		$13,592	Forecasted Therms	9,753,086		**$114,049**	**$ 17,707**	Forecasted Therms	9,753,086 Therms		**$114,049**
168	**Total Commodity Charge**		**8,245,936 Therms**			**$96,342**									
169															
170	Contract Demand Charge		192000	0.09375		**$18,000**	Contract Demand Charge	192,000	$0.09375	**$18,000**	**$0**	Contract Demand Cha	192000	0.09375	**$18,000**
171	Adjustment					$551									
172	Gross Revenue Fee					$2,569									
173	Previous Month CA1501A -					-$122,910									
174	Current Month CA1501A +					$122,622									
175	**Total Non-Gas Revenue**					**$2,832**									
176															
177	**Total Rate Schedule 903 Revenue**					**$123,173**									

Cascade Natural Gas Corporation Revenue Proof

Test Year: January 1, 2015 Through December 31, 2015

	Present Billing						Current Rates					Proposed Rates			
Line No.	Rate Description	Percent Distribution	Billing Determinants (Therms/Bills)	Rate	Adjusted Billing Determinants	Weather Normalized Revenue (Margin)		Billing Determinants (Therms/Bills)	Rate	Margin	2015 Revenue Adjustment	Percent Distribution	Billing Determinants (Therms/Bills)	Proposed Rate	Proposed Distribution Margin
	(A)	(B)	(C)	(D)	(E)	(F) (D*E)		(G)	(H)	(I)	(I)	(J)	(K)	(L)	(M) (K*L)
Rate 904	**Interruptible Transportation**														
178	**Dispatch Service Charge**		12	500		**$6,000**	**Dispatch Service Charge**	12	$500.00	**$6,000**	**$ -**	**Dispatch Service Charg**	12	500	**$6,000**
179															
180	Commodity Charge Jan-Oct		8,335,770 Therms	0.0078356		$65,316	Commodity Charge		$0.00784			Commodity Charge		0.0078434	
181	Commodity Charge Nov-Dec		1,615,200 Therms	0.0078434		$12,669	Forecasted Therms	10,769,601		**$84,470**	**$ 6,486**	Forecasted Therms	10,769,601 Therms		**$84,470**
182	**Total Commodity Charge**		**9,950,970 Therms**			**$77,984**									
183				0.0877404											
184	Contract Demand Charge		499200	0.0877404		**$43,800**	Contract Demand Charge	499,200	$0.08774	**$43,800**	**$0**	Contract Demand Cha	499200	0.0877404	**$43,800**
185															
186	Gross Revenue Fee					$2,728									
187	Francise Tax					$3,039									
188	Previous Month CA1501A -					-$133,551									
189	Current Month CA1501A +					$133,015									
190	**Total Non-Gas Revenue**					**$5,231**									
191															
192	**Total Rate Schedule 904 Revenue**					**$133,015**									
Rate 905	**Interruptible Transportation**														
193	**Dispatch Service Charge**		12	500		**$6,000**	**Dispatch Service Charge**	12	$500.00	**$6,000**	**$ -**	**Dispatch Service Charg**	12	500	**$6,000**
194															
195	Commodity Charge Jan-Oct		7,566,641 Therms	0.0109666		$82,980	Commodity Charge		$0.01098			Commodity Charge		0.0109776	
196	Commodity Charge Nov-Dec		1,808,027 Therms	0.0109776		$19,848	Forecasted Therms	9,178,906		**$100,762**	**$ (2,066)**	Forecasted Therms	9,178,906 Therms		**$100,762**
197	**Total Commodity Charge**		9,374,668 Therms			**$102,828**									
198															
199	Contract Demand Charge		480000	0.04375		**$21,000**	Contract Demand Charge	480,000	$0.04375	**$21,000**	**$0**	Contract Demand Cha	480000	0.04375	**$21,000**
200															
201	Gross Revenue Fee					$2,771									
202	Previous Month CA1501A -					-$132,599									
203	Current Month CA1501A +					$136,450									
204	**Total Non-Gas Revenue**					**$6,622**									
205															
206	**Total Rate Schedule 905 Revenue**					**$136,450**									
						$67,389,766.28				29,640,042	1,406,860				31,546,329
						67,389,765.96					30,400				
	[1] Adjusting Cascade bill therms for gas used					0					**1,437,260**				

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

Pamela J. Archer
Exhibit No. 402

Tariff Sheets

RATES, RULES, AND REGULATIONS
FOR
NATURAL GAS SERVICE
IN
OREGON

Including service to the communities of:
Athena, Baker, Bend, Boardman, Chemult, Crescent, Gilchrist, Hermiston, Huntington, Irrigon, Lapine, Lime, Madras, Milton-Freewater, Mission, Nyssa, Ontario, Pendleton, Pilot Rock, Prineville, Redmond, Stanfield, Sunriver, Umatilla, and Weston.

INDEX

RULES

PUBLIC PURPOSES

RATE SCHEDULES

(continued)

INDEX

RATE SCHEDULES (continued)

RATE ADJUSTMENTS

OTHER CHARGES

OPTIONAL SERVICES

RULE 1
GENERAL

1. The Company shall furnish natural gas in compliance with the rules and regulations as established in this Tariff, and all subsequent revisions as approved by the Public Utility Commission of Oregon.

2. No officer, employee, agent, or representative of the Company has any right to waive, alter, or amend in any manner the rules and regulations established in this Tariff, or any part thereof.

3. Service shall be furnished provided adequate capacity exists in the Company's system.

4. The natural gas supplied by Cascade may vary in different localities. The total gross heating value of the gas deliverable shall not be less than 985 BTUs.

RULE 2
DEFINITIONS

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

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

2. BTU - British Thermal Unit

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

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

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

6. Customer - Any person, firm, or corporation that has applied for, been accepted, and is currently receiving gas and, or distribution service from the Company under these Rules and Regulations at one location under one rate classification contract.

7. Curtailment **-** An event when the Company must interrupt service to customers in accordance with Rule 17. A Curtailment event may affect any level of service depending on the severity and geographical scope of the event.

8. Customer Classifications:
   A. Residential - Service to a single family dwelling, two family (duplex) dwelling or to an individual dwelling unit in a multiple family dwelling building for residential purposes including space heating, water heating, and cooking.

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

(continued)

RULE 2
DEFINITIONS

DEFINITIONS (continued)

Customer Classifications (continued)

B. Commercial - Service to a customer engaged in selling, warehousing, or distributing a commodity, in some business activity or in a profession, or in some form of economic or social activity (office, stores, clubs, hotels, etc.) and for purposes that do not come directly under another classification of service.

C. Industrial - Service to a customer engaged in a process which creates or changes raw or unfinished materials into another form or product. (Factories, mills, machine shops, mines, oil wells, refineries, pumping plants, creameries, canning and packing plants, shipyards, etc., i.e., in extractive, fabricating or processing activities).

D. Institutional - Service to a customer of a public character including but not limited to governmental buildings, colleges, schools, hospitals, clinics, institutions for the care or detention of persons, and similar establishments.

E. Interruptible Gas - An interruptible gas service customer is considered “non-core” and receives a reduced rate on natural gas service because this class of customers is the first curtailed when gas supply or distribution is constrained for reasons other than force majeure.

F. Transportation - Transportation customers purchase their own natural gas and procure only distribution services from the Company.

9. Gas Day - A twenty-four hour period beginning daily at 7:00 a.m. Pacific Clock Time (PCT), which is Pacific Standard Time or Daylight Savings Time in Kennewick, Washington, whichever is effective at the time of reference. The Company's Gas Day coincides with the Gas Day established in Northwest Pipeline’s tariff, which may change from time to time, upon approval of the Federal Energy Regulatory Commission (FERC).

10. Essential Agricultural Use - As established by the Secretary of Agriculture under section 401(c) of the Natural Gas Policy Act of 1978 (NGPA), or identified in 7 CFR 2900, et seq. and amendments thereof, essential agricultural use is gas use (1) For agricultural production, natural fiber production, natural fiber processing, food processing, food quality maintenance, irrigation pumping, crop drying; or (2) As a process fuel or feedstock in the production of fertilizer, agricultural chemicals, animal feed, or food which the Secretary of Agriculture determines is necessary for full food and fiber production.

11. Firm Service - The sale of natural gas on a firm basis where the Company will exercise reasonable diligence to supply and deliver continuous service to customers not receiving interruptible service. See Order of Priority in Rule 17.

(continued)

RULE 2
DEFINITIONS

DEFINITIONS (continued)

12. High Priority Use - As defined in 281.203(a), Title 18 Code of Federal Regulations, high priority use is natural gas in a residence, a small commercial establishment, in a school or hospital, or for police protection, for fire protection or in a correctional facility.

13. Month - The period of time between and including the date of the current meter read and the date of the prior meter read which is the period upon which the Customer's monthly bill is based. A billing month may be contained within a single calendar month, or may encompass a portion of two separate calendar months.

14. Premise - All of the real property and personal property in use by a single customer on a parcel of land which comprises the site upon which customer facilities are located and to which natural gas service is provided.

15. Tariff - This Tariff, including all schedules, rules, regulations, and rates as they may be modified or amended from time to time.

16. Therm - A unit of heating value equivalent to 100,000 BTUs.

17. WACOG - The Weighted Average Commodity Cost of System Supply Gas (WACOG) reflected in Cascade's tariffs shall be as established by gas cost tracking or other similar filings.

RULE 3
ESTABLISHING SERVICE

REQUIREMENTS FOR ESTABLISHING SERVICES
To establish service with the Company, an applicant must do the following:

1. Provide the Company with: a) the date service is to begin; b) whether the premise has previously received service from the Company; c) the purpose for which the gas is to be used; d) whether the applicant owns or rents the premise; e) the applicable rate schedule; and f) any other information that the Company deems necessary;
2. Establish Identity in accordance with the requirement in Section A below in this Rule; and
3. Establish Credit in accordance with the requirements found in Section B below in this Rule.

By establishing service, a customer agrees to be bound by all the terms and conditions of service as established in the Company Tariff as periodically revised and approved by the Public Utility Commission of Oregon.

A. ESTABLISHING IDENTITY

To establish an account, each applicant, including an applicant for co-customer, is required to provide documentation verifying his/her identity. Cascade may require: a) the name of person responsible; b) name on the account if different; c) birthdate; d) Social Security Number; e) valid Oregon driver's license; f) service address; g) billing address if different; h) telephone numbers where applicant can be reached; and I) other information as deemed necessary by the Company.

If the applicant does not wish to provide his/her Social Security Number or valid driver's license, he/she may provide a valid State or Federal picture identification; a combination of a birth certificate and current school or employer picture identification; the name of another person that can verify the applicant's identity; or other information deemed sufficient by the utility.

Once an account is established, at the customer's request, Cascade will restrict access of the account by other individuals through the use of a password.

B. ESTABLISHING CREDIT

Below are the criteria for establishing credit for residential and non-residential customers, respectively. A customer who cannot meet the requirements put forth below must pay a Deposit in accordance with the terms and conditions in Rule 4.

(continued)

RULE 3
ESTABLISHING SERVICE

ESTABLISHING SERVICE (continued)

1. **RESIDENTIAL SERVICE**
   Satisfactory credit may be established by any of the following:
   a. Received twelve months of continuous utility service (of same type) in the preceding 24-month period and the utility can verify that the applicant voluntarily terminated service and paid for services as required;

   b. Provides proof of ability to pay by providing either proof of employment during the prior 12-month period, or statement by income provider that applicant has a regular source of income; or

   c. Meets the Commission approved minimum credit requirements based on a third party credit report score or the Company's own credit scoring formula.

2. **NON RESIDENTIAL SERVICE**
   A non-residential applicant or customer may establish credit if either of the following is verified:

   a. The non-residential applicant or customer has received continuous utility service of a type and in quantities similar to the service for which application is made during the 12-month period prior to the date of the credit screen and has not received any notices of disconnection during such period; or

   b. The non-residential applicant or customer is licensed to do business in the state of Oregon and has kept current over the past twelve months on all real estate mortgages or lease agreements, commercial loans, utility bills and trade accounts.

COMPLIANCE TO RULES AND REGULATIONS

By establishing an account, a customer agrees to comply with all the applicable rules and regulations as established in this Tariff as revised from time to time.

RULE 4
CUSTOMER DEPOSITS

RESIDENTIAL DEPOSIT REQUIREMENTS

1. An applicant or customer may be required to pay a deposit when the applicant:
   a. Is unable to establish credit as outlined in Rule 3;
   b. Received the same type of service from any Oregon energy utility within the prior 24 months and owed a balance when service was terminated; or
   c. Was previously terminated for theft of service by any Oregon utility, found to have tampered with the meter, or diverted service.

2. In lieu of paying a deposit, the applicant may provide a written surety agreement from a responsible party.

3 A deposit required under these rules shall not exceed one-sixth the amount of reasonable estimated billing for one year at rates then in effect. This estimate shall be based upon the use of service at the premise during the prior year or upon the type and size of the customer's equipment that will use the service.

4. Any additional or subsequent deposit may be required as a condition of continued service if any of the following are true:

   a. If the customer remodels, adds gas appliances or moves, and the anticipated usage will be at least 20 percent greater than that upon which the prior deposit was based;
   b. The customer gave false information to establish an account and/or credit status; or
   c. The customer has stolen service, tampered with the meter, or diverted service.

5. Paying a deposit does not excuse a customer from complying with Cascade's tariffs or other regulations on file with the Commission, such as the obligation to pay bills promptly.

DEPOSIT PAYMENT ARRANGEMENTS FOR RESIDENTIAL SERVICE

1. When a deposit is required by Cascade, the consumer may pay the deposit in full or elect to pay the deposit in three installments. The first installment is due immediately. The remaining installments are due 30 days and 60 days after the first installment payment. Except for the last payment, installments shall be the greater of $30 or one-third the deposit.

2. Where an installment payment of a deposit is made together with a payment for gas service, the amount paid shall first be applied toward payment of the amount due for deposit.

(continued)

RULE 4
CUSTOMER DEPOSITS

DEPOSIT PAYMENT ARRANGEMENTS FOR RESIDENTIAL SERVICE (continued)

3. In the event a consumer is required to pay an additional deposit, the customer shall pay within five days one-third of the total deposit, or at least $30, whichever is greater. The remainder of the deposit is due under the terms of Subsection 1. If the customer has an existing deposit installment agreement, the remaining installment payments will be adjusted to include the additional deposit; however, two installment payments cannot be required within the same 30-day period.

4. Where a customer enters into an installment agreement for payment of a deposit under Subsection 1 of these rules, Cascade shall provide written notice explaining its deposit requirements. The notice shall specify the date each installment payment shall be due and shall include a statement printed in boldface type informing the person that service will be disconnected if payment is not received when due. The notice shall also set forth the name and telephone number of the appropriate unit within the Department of Human Services or other agencies which may be able to help the customer obtain financial aid.

5. If a customer fails to abide by the terms of a deposit installment agreement, the Company may disconnect service after a five-day notice. The notice shall contain the information and shall be served in the manner set forth in Rule 5.

6. Where good cause exists, Cascade may provide more liberal arrangements for payment of deposits than those set forth in this rule. Cascade shall keep a written record of the reasons for such action.

7. Should disconnection for nonpayment of a deposit occur, the person disconnected shall be required to pay the full amount of the deposit, and any applicable reconnection fee, disconnect visit charge, late-payment fee, and one-half the past due amount before service is restored. The balance of the past-due amount shall be paid within 30 days of the date service is restored. A customer may continue with an existing time-payment agreement by paying all past-due installments, along with the full deposit and other applicable fees.

NONRESIDENTIAL DEPOSIT REQUIREMENTS

1. Deposit Requirement - Nonresidential (Seasonal and Non-seasonal Service). A deposit may be required equal to one-sixth the estimated annual usage at the service address if an applicant or customer:
   a. Does not satisfy the credit-screening criteria set forth in Rule 3.

(continued)

RULE 4
CUSTOMER DEPOSITS

NONRESIDENTIAL DEPOSIT REQUIREMENT (continued)

b. Owes a bill that is overdue by thirty (30) days or more;
c. Was previously exempted from paying a deposit based upon false information given at the time of application;
d. Is involved in a bankruptcy action, liquidation, bulk sale or financial reorganization; or
e. Is adding incremental demand at a premise with an existing service account.

DEPOSIT PAYMENT ARRANGEMENTS FOR NON-RESIDENTIAL SERVICE

1. An applicant for nonresidential service who is required to pay a deposit shall pay the deposit in full prior to receiving service. An applicant for nonresidential service may also fulfill the deposit requirement with an irrevocable letter of credit, surety bond (performance bond) or some other form of guarantee acceptable to the Company.

2. An existing nonresidential customer is considered to be an applicant for purposes of satisfying the deposit requirement. An existing nonresidential customer, if required to pay or supplement a deposit, is required to pay the full amount within 10 days of the date of the notice from the Company that such a deposit is required. This notice will also serve as the notice of disconnection required under OAR 860-021-0505.

3. If service is disconnected for nonpayment of a deposit, the customer disconnected will be required to pay the full amount of the deposit, plus any applicable reconnection fee, disconnect visit charge, late payment fee and past due account balance before service is restored.

INTEREST ON DEPOSITS FOR RESIDENTIAL AND NONRESIDENTIAL SERVICE

1. Unless otherwise specified by the Commission, customer deposits shall accrue interest at a rate based upon the effective interest rate for new issues of one-year Treasury Bills issued during the last week of October as determined by the Commission in Docket No. UM 779. This interest rate, rounded to the nearest percent, shall apply to deposits held during January 1 through December 31 of the subsequent year.

2. Upon payment of a deposit, Cascade shall furnish a receipt showing the date, name of the applicant or customer, the service address, the amount of deposit, a statement that the deposit will accrue interest at the rate prescribed by the Commission, and an explanation of the conditions under which the deposit will be refunded.

3. If the deposit is held beyond one year, accrued interest will be paid through a credit to the customer's account. If held less than one year, interest will be prorated. Cascade shall keep a detailed record of each deposit received until the deposit is credited or refunded.

(continued)

RULE 4
CUSTOMER DEPOSITS

REFUND OF DEPOSITS FOR RESIDENTIAL AND NONRESIDENTIAL SERVICE

1. Upon termination of service, a customer's deposit plus accrued interest, shall first be applied to any unpaid balance on the customer's account and any remaining balance will be refunded to the customer.

2. Cascade may continue holding a deposit until such time as credit is satisfactorily established or reestablished. For purposes of this rule, credit shall be considered to be established or reestablished if one year after a deposit is made:

   a. The account is current;
   b. Not more than two five-day disconnection notices were issued to the customer during the previous 12 months; and
   c. The customer was not disconnected for nonpayment during the previous 12 months.

3. After satisfactory credit has been established or reestablished, the deposit plus any accrued interest shall be promptly credited to the customer's account or refunded at the customer's request.

4. In the event the customer moves to a new address within Cascade's service area, the deposit, plus accrued interest, will be transferred to the new account.

5. Unless otherwise specified by the customer, Cascade shall mail deposit refunds to the customer's last known address. Valid claims for refunds received within one year of the date service was terminated shall be promptly honored. Funds held beyond one year will be disposed of in accordance with ORS 98.316.

RULE 5
DISCONTINUATION OF SERVICE

GROUNDS FOR DISCONNECTING GAS SERVICE

1. Gas service may be disconnected:

    a. For failing to pay a deposit or make payments in accordance with the terms of a deposit payment arrangement (Rule 4);

    b. For providing false identification or verification of identity;

    c. Where facilities provided are unsafe or do not comply with state and municipal codes governing service or the rules and regulations contained in this Tariff;

    d. Where the customer does not cooperate in providing access to the meter;

    e. Where a customer requests Cascade to disconnect service or close an account;

    f. Where dangerous or emergency conditions exist at the service premise;

    g. For failure to pay Oregon tariff or price listed charges due for services rendered, or by meter tampering, diverting service, or other theft of service (Rule 5);

    h. For failure to abide by the terms of a time-payment agreement; or

    i. Where the Commission approves the disconnection of service.

VOLUNTARY DISCONNECTION

Every customer who is about to vacate any premise supplied with gas service, or who for any reason wishes to have such service discontinued, shall give five days' notice to the Company in advance of specified date of discontinuance of service. Until the Company has such notice, the customer shall be held responsible for all service rendered.

EMERGENCY DISCONNECTION

In emergencies endangering life or property, a utility may terminate service without following the procedures set forth in this rule. However, Cascade shall immediately thereafter notify the Commission. In such cases, where the necessity for emergency termination was through no fault of the customer, there will be no charge made for restoration of service.

(continued)

RULE 5
DISCONTINUATION OF SERVICE

DISCONNECTION OF SERVICE ON WEEKENDS AND HOLIDAYS
Gas service shall not be disconnected for nonpayment on or the day prior to a weekend or a state or utility-recognized holiday.

NOTICE OF PENDING DISCONNECTION OF RESIDENTIAL SERVICE

1. Notice requirements are waived where safety concerns, or meter tampering, diverting of service, or other theft of service is detected. When a written notice is given under these rules:

   a. The notice shall contain multilingual information as required by Commission rules and be served on the customer's designated representative, if any;

   b. If Cascade's records show that the billing address is different from the service address, and Cascade has reason to believe the address is occupied by someone other than the customer, Cascade shall provide a five-day notice to both the occupants of the service address and to the customer's mailing address. The notice may be addressed to "tenant" or "occupant." The envelope shall bear a bold notice stating "Important notice regarding continuance of gas service" or similar words. The notice to occupants may not include the dollar amount owing.

   c. When Cascade's records show service is to a master-metered multi-family dwelling (including rooming houses), Cascade must notify the Commission's Consumer Services Section at least five business days prior to disconnecting the service. Cascade will use reasonable efforts to notify occupants of the impending disconnection and alternatives available to them.

2. The notice shall be printed in **bold face type** and shall state in easy to understand language:

   a. The reason for the proposed disconnection;

   b. The amount to be paid to avoid disconnection;

   c. The earliest date for disconnection;

   d. An explanation of the time-payment agreement provisions;

   e. An explanation of the medical certificate provisions;

   f. The name and telephone number of the appropriate unit of the Department of Human Services or other agencies which may be able to provide financial aid; and

   g. An explanation of the Commission's complaint process and toll-free number.

(continued)

RULE 5
DISCONTINUATION OF SERVICE

NOTICE OF PENDING DISCONNECTION OF RESIDENTIAL SERVICE (continued)

3. At least 15 days before Cascade disconnects a residential customer for nonpayment of services rendered, Cascade will provide written notice to the customer. A 15-day notice is not required when disconnection is for failure to establish credit, theft of service, or safety.

4. A notice of disconnection may not be sent prior to the due date for payment of a bill.

5. Cascade may serve the 15-day notice of disconnection in person or send it by first class mail to the last known address of the customer. Service is complete on the date of the mailing or personal delivery.

6. At least five business days before the proposed disconnection date, Cascade must mail or deliver a written disconnection notice to the customer.

   a. The disconnection notice shall inform the person that service will be disconnected on or after a specific date and shall explain the alternatives and assistance that might be available.

   b. If notification is made by delivery to the residence, Cascade shall attempt personal contact. If personal contact cannot be made with the customer or an adult resident, Cascade shall leave the notice in a conspicuous place at the residence.

7. On the day that Cascade expects to disconnect service and prior to disconnection, Cascade will make a good faith effort to personally contact the customer or an adult at the residence scheduled to be disconnected.

   a. If the contact is made, Cascade shall advise the person of the proposed disconnection;

   b. If contact is not made, Cascade must leave a notice in a conspicuous place at the residence informing the customer that service has been, or is about to be, disconnected.

8. Where personal contact is made by the Company under this rule, and the circumstances are such that a reasonable person would conclude that the customer does not understand the consequences of disconnection, the Company must:

   a. Notify the Department of Human Services and the Commission; and

   b. Delay the proposed disconnection date for five additional business days.

(continued)

RULE 5
DISCONTINUATION OF SERVICE

NOTICE OF PENDING DISCONNECTION OF RESIDENTIAL SERVICE (continued)

9. Where personal contact is made, the representative of the Company making contact shall be empowered to accept reasonable partial payment of the overdue balance in accordance with the time payment provisions.

10. Cascade must document its effort to provide notice and shall make the documentation available to the customer and the Commission upon request.

EMERGENCY MEDICAL CERTIFICATE FOR RESIDENTIAL SERVICE

1. Cascade shall not disconnect residential service if the customer submits certification from a qualified medical professional stating that disconnection would significantly endanger the physical health of the customer or a member of the customer's household. "Qualified medical professional" means a licensed physician, nurse-practitioner, or physician's assistant authorized to diagnose and treat the medical condition described without direct supervision by a physician.

2. An oral certification must be confirmed in writing within 14 days by the qualified medical professional prescribing medical care. Written certification must include:

   a. The name of the person to whom the certificate applies and relationship to the customer;

   b. A complete description of the health condition;

   c. An explanation how the health of the person will be significantly endangered by the termination of service;

   d. A statement indicating how long the health condition is expected to last;

   e. A statement specifying the particular type of utility service required (e.g. gas for heating); and

   f. The signature of the qualified medical professional prescribing medical care.

3. An emergency medical certificate shall be valid only for the length of time the health endangerment is certified to exist, but no longer than six months without renewal. At least 15 days before the certificate's expiration date, Cascade will give the customer written notice of the date the certificate expires unless it is renewed with Cascade before that day arrives.

(continued)

RULE 5
DISCONTINUATION OF SERVICE

EMERGENCY MEDICAL CERTIFICATE FOR RESIDENTIAL SERVICE (continued)

4. A customer submitting a medical certificate is not excused from paying for gas service.

   a. Customers are required to enter into a written time-payment agreement with Cascade where an overdue balance exists. Terms of the time-payment agreement shall be those set forth in this Rule 5 or other terms as agreed upon in writing between the parties.

   b. Where financial hardship can be shown, a customer with a medical certificate shall be permitted to renegotiate the terms of a time-payment agreement with Cascade.

   c. Time-payment arrangements in effect when a medical certificate terminates remain in effect for the balance then owing. If a customer fails to pay charges incurred after the certificate terminates, standard time-payment provisions (Rule 5) will apply to payment of the arrearage incurred after the medical certificate expires. The terms of the medical certificate time-payment plan continue to apply to the arrearage accrued during the disability.

5. If a medical certificate customer fails to enter into a written time-payment agreement within 20 days of filing the certificate or to abide by its terms, Cascade shall notify the Commission's Consumer Services Section of its intent to disconnect service and the reason for the disconnection. Cascade may disconnect service after providing a notice 15 days in advance of disconnection for nonpayment, or five days before disconnection for failure to enter into a written time-payment agreement. The notice shall comply with the requirements of Part I, Subsection 2, except that Subsection e shall not apply. A hearing may thereafter be held to determine whether Cascade should be permitted to disconnect service to the customer.

6. Cascade may verify the accuracy of a medical certificate. If Cascade believes a customer does not qualify, or no longer qualifies for a medical certificate, Cascade may apply to the Commission for permission to disconnect the customer's service.

TIME-PAYMENT AGREEEMENTS FOR RESIDENTIAL SERVICE (NON MEDICAL CERTIFICATE CUSTOMERS)

1. Cascade will not disconnect residential service for nonpayment if a customer enters into a written time-payment plan. Cascade will offer customers a choice of payment agreements. At a minimum, the customer may choose between a levelized payment plan and an equal payment arrearages plan.

(continued)

RULE 5
DISCONTINUATION OF SERVICE

TIME-PAYMENT AGREEEMENTS FOR RESIDENTAIL SERVICE (NON MEDICAL CERTIFICATE CUSTOMERS) (continued)

2. A customer who selects a levelized-payment plan will pay a down payment equal to the average annual bill including the account balance, divided by twelve, and a like payment each month for eleven months thereafter.

    a. Cascade shall periodically review the monthly installment plan. If necessary, due to changing rates or variations in the amount of service used by the customer, the installment amount may be adjusted to bring the account into balance within the time period specified in the original agreement.

    b. If a customer changes service address at any time during the period of a time-payment agreement, provided that payments are then current and the customer pays other tariff charges associated with the change in residence, Cascade shall recalculate the customer's deposit and/or monthly installment. The recalculated amount shall reflect the balance of the account at the previous service address and the average annual bill at the new service address for the months remaining in the original time-payment agreement. When installments on a time-payment agreement have not been kept current, a customer shall be required to pay all past-due installments, together with any other applicable charges before service is provided at the new residence.

3. A customer who selects an equal payment arrearages plan will pay a down payment equal to one-twelfth the amount owed for past gas service (including the overdue amount and any amounts owed for a current bill or a bill being prepared but not yet delivered to the customer). Each month, for the next eleven months, an amount equal to the down payment will be added to, and payable with, the current charges due for service. If a customer changes service address at any time during the period of an arrearages payment plan, the plan continues. However, the customer must pay any past-due charges and all other applicable charges before Cascade provides service at the new address.

4. Cascade and the customer may agree in writing to an alternate payment arrangement, provided Cascade first informs the customer of the availability of the payment terms set forth in this rule.

5. If a customer fails to abide by the time-payment agreement, Cascade may disconnect service after serving 15 days' notice.

(continued)

RULE 5
DISCONTINUATION OF SERVICE

FIELD VISIT CHARGE
A Field Visit Charge as established in Schedule 200 may be charged whenever Cascade is required to visit a residential service address for the purpose of disconnecting or reconnecting service, but due to the customer's action, is unable to complete the reconnect or disconnect.

LATE PAYMENT CHARGE
A Late-Payment Charge as established in Schedule 200 will be applied to overdue account balances, both residential and nonresidential, at the time of preparing the subsequent month's bill. The Late-Payment Charge may not be applied to time-payment or equal-payment accounts that are current, and will be applied only to accounts that have an overdue balance greater than $200. The Commission will determine the Late-Payment Charge by surveying prevailing market rates for late-payment charges of commercial enterprises. The Commission will notify Cascade by November 15 of each year what rate may be used to determine late-payment charges on overdue customer accounts during the following calendar year. The current late-payment rate and the conditions for its application to customer accounts shall be specified on the gas bill.

RULE 6
BILLING

GENERAL

Gas consumed, as indicated by meter readings, will be billed to customers as promptly as possible after reading dates, at approximately thirty day intervals, computed per applicable filed tariff rates. Bills will be due and payable as of dates rendered and delinquent or past due fifteen days thereafter.

When an under- or overbilling occurs, Cascade shall provide written notice to the customer detailing the circumstances, period of time, and amount of adjustment. The exception to these provisions is if issuing a correction is uneconomical in the sole view of the Company.

1. Underbillings: For underbillings, the Company may issue a bill correction if the error occurred within the prior twelve month period ending on the date on which the customer or former customer was last billed. The Company will not issue billing corrections for underbillings in excess of two years (twenty-four months). However, if an underbilling is a result of fraud, tampering, diversion, theft, misinformation, false information or other unlawful conduct on the part of the customer or former customer, the Company may collect full payment for any amount owed without limitation.

   Where a Customer is required to repay an underbilling, the Customer shall be entitled to enter into a time payment agreement without regard to whether the customer already participates in such an agreement. If the customer and Cascade cannot agree upon payment terms, the Commission shall establish terms and conditions to govern the repayment obligation. Cascade shall provide written notice advising the customer of the opportunity to enter into a time payment agreement and of the Commission's appeal and complaint process.

2. Overbillings: For overbillings, the Company will issue a credit for amounts previously overbilled within the prior twelve month period ending on the date on which the customer or former customer was last overbilled. The Company will not issue credits for amounts overbilled for more than three years (thirty-six months) before the date the energy utility discovered the overbilling.

No billing adjustment shall be required if a gas meter registers less than two percent error under conditions of normal operation.

Bills will show dates of readings, readings at beginning of period and end of period, the number of cubic feet, therms, or other units of measurement of gas consumed, the tariff schedule code applicable, the delinquent date of bill, and the amount of the bill. Any estimated reading shall be clearly noted on the bill.

Cascade should make reasonable efforts to prepare opening and closing bills from actual meter readings.

(continued)

RULE 6
BILLING

ESTIMATED BILLING CAPABIILITY
The Company may issue small commercial customers and residential customers excluding accounts with pool water heating load an estimated bill during the months of June through September. Actual meter readings will be made the month following any month in which the customer's bill is estimated.

TRANSFER BILLINGS
If Cascade identifies that a customer owes Cascade a balance from the customer's prior account for Oregon service, Cascade may transfer the amount to the customer's current account after giving the customer notice of the transfer, the amount due under the prior account, the period of time during which the balance was incurred and the service address under which the bill was incurred. The notice must also meet the provisions for notifications as established in Rule 5. If the bill is identified at the time a customer changes residences, the provisions of this rule apply.

If the customer has six months or more remaining on a time-payment agreement, the installment amount will be adjusted in order to bring the account into balance within the time period specified in the original agreement. If the customer has less than six months remaining on a time-payment agreement, Cascade will recalculate the agreement to bring the account into balance within 12 months. The customer must pay any past due time-payment installments before Cascade adjusts or recalculates the agreement. Cascade may make more liberal payment arrangements for customers on medical certificates who cannot reasonably be expected to pay the outstanding balance in the time otherwise applicable under this rule.

BUDGET PAYMENT PLAN FOR PAYMENTS OF GAS BILLS
The budget payment plan for payment of gas bills is devised to average out the monthly payments for gas service of any residential customer who can establish satisfactory credit with the Company.

At the request of a residential customer with satisfactory credit and no balance outstanding, the Company will estimate the customer's annual billing for gas service, based on the previous twelve months' usage. The estimated amount will then be divided by twelve. The resultant amount, rounded to the next full dollar, shall be the amount the customer will pay in lieu of the regular monthly billing for each month of the budget payment plan period. At the end of the plan year, any outstanding debit or credit balances will be rolled into the estimated usage for the following plan year and will be reflected in that year's monthly budget payment plan amount. Credit balances will be refunded to the customer if the customer specifically requests a refund.

(continued)

RULE 6
BILLING

BUDGET PAYMENT PLAN FOR PAYMENTS OF GAS BILLS (continued)
For each succeeding annual budget payment period the Company will re-estimate the amount of the customer's bills for service for the ensuing period and so advise the customer. Unless the customer advises the Company to the contrary, such new monthly budget payment installments will be used for the ensuing payment period. If the customer requests to leave the plan, any debit balance will be due and payable under the regular terms of payment for gas service; credit balances may be applied to future gas bills or, if the customer so requests, refunded to the customer.

During each budget payment plan period the customer shall be entitled to receive gas service so long as the customer pays each monthly budget payment plan installment as it becomes due. If a customer fails to comply with the terms of this plan, the budget payment plan will be discontinued and the customer will be billed monthly on the basis of actual usage. If a customer fails to comply with the terms of this plan, and has a debit balance, customer may be subject to disconnection of service under Rule 5.

For each billing period the customer will receive a bill showing the amount of gas used during the billing period, the charge for such gas used, the balance of account and the amount of the current month's budget payment plan installment.

Any estimates furnished by the Company in connection with such budget payment plan shall not be construed as a guarantee or assurance that the total actual charges will not exceed the estimates. The Company may at any time submit a revised estimate to the customer and require that the customer pay the revised monthly budget payment plan installment as a condition to the continuation of the budget payment plan for that customer.

Such estimates or any revising thereof shall apply only to the premise then occupied by the customer. If the customer vacates such premise and moves to a different premise served by Cascade, the amount of the budget payment will be re-estimated and the customer will be advised of the change. If the customer will not desire natural gas service from Cascade at the new premise, the budget payment plan shall immediately terminate and any amount payable from the customer will be due and payable under the regular terms of payment for gas service; any amount due the customer by the Company shall be refunded.

RETURNED PAYMENT FEE
The Company will charge a Returned Payment Fee, as established in Schedule 200, for any payment returned unpaid.

(continued)

RULE 6
BILLING

CONVERSION OF METER MEASUREMENTS TO THERMS

All meter measurements for gas service shall be converted to a therm basis for billing purposes. Such conversion shall be based on the temperature of the gas, the absolute pressure of the gas, and the measured heating values at standard conditions of the gas received from the pipeline supplier(s).

In cases where meters are not mechanically or electronically corrected for temperature, monthly temperature correction factors (Heat Value Multiplier) will be used to determine customer billing therms. The Heat Value Multiplier is calculated as the current pipeline heating value times a temperature factor of 520, divided by the sum of 460 and the published 30-year normal average temperature data.

In cases where meters are not mechanically or electronically corrected for pressure, a Pressure Factor will be used to determine customer billing therms. The Pressure Factor equals the sum of individual customer delivery pressure and the following applicable atmospheric pressure, both divided by 14.73 psi, (atmospheric pressure at sea level).

Town	Atmospheric Pressure, psi
Athena	13.86
Baker	13.03
Bend	12.95
Boardman	14.61
Chemult	12.42
Crescent	12.59
Gilchrist	12.59
Hermiston	14.50
Huntington	13.67
Irrigon	14.58
Madras	13.60
McNary	14.50
Milton-Freewater	14.21
Mission	14.11
Nyssa	13.63
Ontario	13.65
Pendleton	14.19
Pilot Rock	13.90
Prineville	13.30
Redmond	13.24

(continued)

RULE 6
BILLING

CONVERSION OF METER MEASUREMENTS TO THERMS (continued)

Town	Atmospheric Pressure, psi
Stanfield	14.43
Sunriver	12.70
Umatilla	14.58
Vale	13.60
Weston	13.87

RULE 7
METERS

METERS
Each customer must furnish a convenient, safe and adequately sized location for a meter that is acceptable to the Company and where the meter is readily accessible for reading, inspecting, turning off or on, and removing for testing whenever necessary.

No charge will be made for installation of billing meters. When a customer desires, for his/her convenience, the installation of more than one meter at one premise for one class of service, the Company may install such other meters, providing physical conditions or excessive installation costs do not make the installation of a master meter impractical. In such cases where a master meter is not installed, each meter so located on one premise for one class of service shall be billed as a separate meter having separate minimum charges. However, where practical, the Company will install a master meter.

Services shall be through one or more meters, at the option of the Company. No extension whatsoever of customer-owned piping shall be made for the purpose of supplying gas to adjacent property.

The Company will not be required to furnish, install, maintain, read, or test submeters.

Meters will be read once a month as nearly on the same date each month as Saturdays, Sundays and holidays will permit.

If, for any reason whatsoever, the Company's employees cannot gain access to the meter for the purpose of reading the index thereof, an estimated bill will be rendered and the same will be considered a regular billing. The Company will seek the customer's cooperation in obtaining monthly readings in the event that meter access cannot be obtained.

Any estimated bill or customer provided reading shall be subject to actual verification by the utility not less than once every four months.

RULE 8
METER TESTING

STATISTICAL METER SAMPLING PROGRAM

Except for meters which are in the Company's statistical sampling program, every gas meter will be tested at least once in a ten year period.

The Company may elect to keep diaphragm type meters with rated capacity of up to 3,000 cfh in service for intervals beyond ten years, provided the meter performance meets the criteria of the Company's statistical sample program as approved by the Commission.

The Company's statistical sample program will meet the requirements set forth in Part IV ("In-Service Performance"), of the 1992 version of ANSI B109.1 and B109.2, and shall be based on generally accepted statistical methods within the industry for predicting the sampling distribution of the proportion of a population, with a 90% degree of confidence.

More specifically, the sampling program shall determine from a random sample of sufficient size that, nine times out of ten, as many as 80% of the meters in a meter group (population) are within the percent accuracy limits of 98.0% and 102.0% (i.e. accuracy requirement), and with no more than 10% of the meters in a group exceeding 102.0% accuracy (i.e., not fast requirement). If it is determined that fewer than 80% of the meters in a group meet the accuracy requirement or more than 10% of the meters in a meter group exceed the not fast requirement, corrective action will be taken.

Corrective action shall consist of either a selective removal program to raise the accuracy performance of the group to acceptable standards or the removal of the entire group from service. The rate of removal will be such that the required corrective action is completed as soon as practicable but not to exceed a period of two years after the year testing was performed. However, with Commission approval, the period for removal may be extended an additional two years in any year which the total number of meters required for removal exceeds four percent of the number of meters in the Statistical Sample Program.

For further details, a copy of the Statistical Sample Program can be obtained by writing to the Manager, Measurement, c/o Cascade Natural Gas Corporation, 8113 W. Grandridge Blvd, Kennewick, WA 99336.

METER ACCURACY STANDARD

Before being installed for customer use, meters whether new or reconditioned, will be in good order and be adjusted to register correct consumption with an accuracy bandwidth of two percent (2%) fast or slow.

(continued)

RULE 8
METER TESTING

CUSTOMER REQUESTED METER TESTING (continued)
Any customer may request the Company to test his/her meter. Company shall make such test at its central meter shop within twenty (20) days of receipt of request and no payment or deposit will be required for such test.

Should customer request a meter test more often than once in every twelve (12) month period, a Deposit for Meter Test as established in Schedule 200 to cover the reasonable cost of the test may be required of the customer. The amount so deposited will be returned to the customer if the meter is found, upon test, to register more than two (2) percent fast.

All meters will be tested in Company's central meter shop located in Yakima, Washington. A customer shall have the right to require Company to conduct the test in his/her presence at Yakima, or if he/she so desires, in the presence of a representative appointed by him/her.

A report giving customer's name, date of request, address of service location, the type, make, size and meter number, the date tested, and result of test will be supplied to the customer within a reasonable time after completion of test.

RULE 9
SERVICE LINE INSTALLATIONS

SERVICE INSTALLATIONS

The Company will provide a customer's service line, from the service connection at the main in the alley, street or right-of-way abutting the customer's premise, to and including the meter, but the customer shall pay for the installed cost of any length of service line in excess of forty (40) feet inside the customer's property line abutting the alley, street or right-of-way in which the main is situated, except that:

Customers who install gas fired appliances as the primary means to perform the following requirements shall receive free footage in excess of the forty (40) feet minimum up to the amounts listed below:

Requirement	No Direct Cost
Space heating only[1]	20 feet
Space heating and water heating [1]	40 feet
Commercial and Industrial with over 150,000 Btu connected load (in lieu of space and water heating)	40 feet

(1) Applies to all classes of service.

The Company reserves the right to designate the location of service line, meters and regulators, and select the amount of space which must be left unobstructed for the installation.

In the event that the constructed service line footage on customer's premise exceeds the appropriate free footage allowance by 10% or less, there will be no charge. When the service line is rerouted from the originally designated location for the convenience of the Company and constructed service line footage exceeds the appropriate free allowance or any previously agreed excess, no charge will be made for such rerouting excess. Free footage allowances for projects of multiple single family structures shall be the appropriate free allowance multiplied by the number of structures to be served. Free footage allowance for a split service shall be the sum of the appropriate free footage for each structure to be served.

(continued)

RULE 9
SERVICE LINE INSTALLATIONS

<u>SERVICE INSTALLATIONS</u> (continued)
If the Company provides additional free footage of service line, beyond the initial 40 feet, based upon gas appliances identified above, Customer shall be required to sign a Customer Commitment Contract. If the customer fails to install any or all of the gas appliances which provided additional free footage and fails to commence gas usage within 60 days from the date that the service line is installed, the Company shall bill the customer for the cost per foot of such additional footage, including 20.38% to compensate for the cost resulting from customer provided construction funds. If requested by the Company, the customer shall provide the Company with a copy of the installation invoice to verify the installation of the gas appliances. In the absence of installation documentation, the customer shall allow reasonable access to customer's premises for the verification of the installation of those appliances, upon the Company's request. If, subsequent to paying for such costs, the customer installs the agreed upon appliances and commences gas usage within five years from the date the extended facilities were installed, the costs paid to the Company by the customer associated with each installed agreed upon appliance shall be refunded without interest.

The Company shall not be required to relocate an existing service line at no cost to customer where such relocation is to be made for the convenience of the customer.

The customer will indemnify and hold the Company harmless from claim, etc., for trespassing or injury to building and property crossed by the installation of the service line except upon negligence of Company personnel.

<u>EXCESS FLOW VALVES</u>
An Excess Flow Valve is available as an added safety feature in the event that the service line is suddenly severed. At the customer's request, the Company will install an Excess Flow Valve for the fees established in Schedule 200.

RULE 10
MAIN INSTALLATIONS

MAIN EXTENSIONS

The Company will furnish an extension of its distribution main system free of charge to provide firm natural gas service to any applicant for such service located beyond the existing main system up to an estimated cost of construction to provide such service equal to four and one-half (4-1/2) times the estimated gross annual revenue less cost of gas to be derived therefrom.

The Company may require a customer to sign a Customer Commitment Contract prior to the installation of a main extension. If the Company provides a main extension and the customer fails to install any or all of the gas appliances which were included in the extension analysis and fails to commence gas usage within 6 (six) months from the date of the Customer Commitment Contract, the Company shall bill the customer for the costs and expenses associated with its extension of the distribution main, including 20.38% to compensate for the cost resulting from customer provided construction funds, based upon the feasibility of the extension with the actually installed appliances. If requested by the Company, the customer shall provide the Company with a copy of the installation invoice to verify the installation of the gas appliances. In the absence of installation documentation, the customer shall allow reasonable access to customer's premise for the verification of installation of those appliances, upon the Company's request. If, subsequent to paying for such costs, the customer installs the agreed upon appliances and commences gas usage within five years from the date of the Customer Commitment Contract, the costs of the distribution facilities paid to the Company by the customer associated with each installed agreed upon appliance shall be refunded without interest.

The Company may deny any extension if conditions relative to the extension indicate that such service will not be of such permanence as to warrant the expenditure required. The Company may require from the applicant(s) the advance of funds, including 20.38% to compensate for the cost resulting from customer provided construction funds, which may be required in excess of the free allowance; such advance subject to refund without interest on the following basis:

1. An amount equal to four and one-half (4-1/2) times the estimated annual gross margin (gross revenue less cost of gas) to be derived from each additional customer, in excess of the number of customers on which the advance was predicated, whose service line is connected directly to the main extension upon which the advance was made. Such refund shall be granted within thirty (30) days of setting of a meter for such additional customer or customers.

(continued)

RULE 10
MAIN INSTALLATIONS

MAIN EXTENSIONS (continued)

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

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

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

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

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

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

RULE 11
HOUSE PIPING

HOUSE PIPING

All house piping and equipment beyond Company furnished facilities and accessories thereto, necessary to utilize service furnished by the Company, shall be installed by and belong to the customer and be maintained at his or her expense.

House piping shall be installed in accordance with applicable ordinances of the city, town or other such governing body as may have jurisdiction in the locality in which the installation is being made. Lacking other rules or ordinances for house piping, the International Mechanical Code shall apply.

The customer must maintain all fixtures and piping beyond Company furnished facilities. Any loss or damage through leaks beyond Company furnished facilities is at the customer’s risk and expense.

Meters will not be connected with piping known by the Company to be defective, and the Company reserves the right to discontinue service in the event it, at any time, finds the customer-owned piping or appliances on customer's premise defective or in an unsafe condition. The Company does not, however, assume responsibility for inspecting the customer's appliance and piping, nor does it assume liability for such defective or hazardous conditions as may exist therein.

RULE 12
RESPONSIBILITY FOR MAINTENANCE OF SERVICE CONNECTIONS

<u>RESPONSIBILITY FOR MAINTENANCE OF SERVICE CONNECTIONS</u>
In the absence of a special contract between the Company and the customer to the contrary, the customer will be responsible for all piping and appliance connections belonging to the customer between the meter and the appliances, and for any service piping belonging to the customer concealed within walls or any other inaccessible locations within buildings or that has reentered the ground after leaving the meter. The customer shall in all cases notify immediately the office of the Company of any leakage or escape of gas on his or her premises.

In the event of gas leakage or escape, no allowance will be made from the amount of gas registered by the meter, nor will the Company be responsible for any damage caused by the escape of gas. The Company's responsibility ceases at the meter except where, pursuant to special contract between the Company and the customer, facilities are owned by the Company on the customer's premises.

RULE 13
TEMPORARY SERVICE

The Company may furnish temporary service under the following conditions if, in its sole opinion, the furnishing of Temporary Service will not create an undue hardship upon it or its existing consumers:

a) The applicant for such temporary service shall be required to pay to the Company in advance or otherwise, as the Company may elect the net cost of installing and removing any facilities necessary in connection with the furnishing of such service by the Company.

b) Each applicant for temporary service shall be required to deposit with the Company a sum of money equal to the estimated amount of the bill for such service, or to otherwise secure, in a manner satisfactory to the Company, the payment of any bills which may accrue by reason of such service so furnished.

c) Temporary service shall not exceed a period of one year.

d) Any balance over and above the net cost of installing and removing any facilities will be returned to the customer upon discontinuation of service if less than one year; if temporary service exceeds one year, thereby becoming permanent, the entire deposit is subject to return at the rate of 20% of the gross revenue each year after the first year resulting from such service. In no event shall the refund exceed the amount of the deposit. All refunds shall cease sixty months after the service becomes permanent.

RULE 14
COMPANY RESPONSIBILITY

The Company will use reasonable diligence in furnishing as uniform a supply of gas as practicable to its firm service customers. In the event Company's supply of gas is insufficient at any time or any location to meet the full requirements of all customers served under firm service rate schedules, the Company may be required to curtail service to customers in accordance with Rule 17, Order of Priority for Gas Service. However, should, the supply of gas fail or be temporarily interrupted by reason of accident or otherwise, the Company upon notice will make reasonable efforts to restore such supply.

Notwithstanding, the Company may interrupt its service to make necessary alterations and repairs, but only for such time as may be reasonable or unavoidable. Except for emergency related interruptions, the Company shall give customers reasonable notice of its intention to interrupt service and shall endeavor to arrange such interruption so as to minimize any inconvenience to customers.

Under the conditions stated above or when the Company deems an emergency warrants interruption or limitation in the service being rendered, such interruption or limitation shall not constitute a breach of contract and shall not render the Company liable for damages suffered thereby or excuse a customer from further fulfillment of the contract.

RULE 15
CUSTOMER RESPONSIBILITY

The Company shall have the right to enter the customer's premise at all reasonable hours for the purpose of inspecting the customer's facilities to ensure the customer is served on the appropriate rate schedule; for installing, removing, testing or replacing the Company's apparatus or property; for reading meters and for the entire removal of the Company's property in event of termination of service for any reason.

The Company shall at all times retain ownership of installed meters and service. All Company property installed in or upon the customer's premise, used and useful in supplying service, is placed in the customer's protection. All reasonable care must be exercised to prevent loss of or damage to such property; ordinary wear is an exception. The customer will be held liable for any loss of property or damage thereto, and shall pay to the Company the cost of necessary repairs or replacements.

Any changes made in the location of service lines or meter installations to suit the customer must be at the customer's expense.

Interference with the meter or its connections, service, mains or other Company property by anyone except employees or authorized agents of the Company is strictly prohibited. No one except the Company employees are allowed to make any repairs or adjustments to any Company-owned equipment including meters. In case of emergency, other authorized parties may shut off the flow of gas at meters.

RULE 16
FORCE MAJEURE

Neither the Company nor the customer shall be liable for damage to the other for any act, omission or circumstances occasioned by or in consequence of any acts of God, strikes, lockouts, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fire, storms, floods, unforeseeable or unusual weather conditions, washouts, arrests and restraint of rulers and peoples, civil disturbances, explosives, breakage or accident to machinery or lines of pipe, line freeze-ups, temporary failure of gas supply, inadequacy of gas supply at any time or any location to meet the full requirements of all customers served by Company, the binding order of any court or governmental authority which has been resisted in good faith by all reasonable legal means, and any other cause, whether of the kind herein enumerated, or otherwise, and whether caused or occasioned by or happening on account of the act or omission of one of the parties to this contract or some person or concern not a party thereto, not reasonably within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome. A failure to settle or prevent any strike or other controversy with employees or with anyone purporting or seeking to represent employees shall not be considered to be a matter within the control of the party claiming suspension.

RULE 17
ORDER OF PRIORITY FOR GAS SERVICE

GENERAL

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

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

ORDER OF PRIORITY

1. Residential customers.

2. Firm Service Commercial and institutional customers as follows:
   a. Commercial and institutional customers served under Rate Schedules 104 and 105.
   b. Commercial or institutional customers served on other firm service rate schedules, and essential agricultural service and other high priority users not covered elsewhere.

3. Firm Service Industrial customers using gas as feedstock in a process in which natural gas is used as a raw material and as plant protection requirements of lower priority customers.

4. Firm Service Industrial customers with consumption of less than 1,000 therms per day.

5. Firm Service Industrial customers with consumption of more than 1,000 therms per day but less than 10,000 therms per day.

6. Industrial customers with consumption of more than 10,000 therms per day, including customers receiving service on Schedule 201, Special Contracts.

7. General distribution system interruptible transportation service customers.

8. Customers receiving interruptible natural gas service.

(continued)

RULE 17
ORDER OF PRIORITY FOR GAS SERVICE

ADMINISTRATION OF CURTAILMENT

When the Company requires a curtailment due to either gas supply or capacity failures, the curtailment shall be imposed first on customers in the lowest order of priority category at the rate of 100% of each customer's requirements (excepting minor requirements for essential services as approved by Company) on a customer-by-customer basis and will then proceed to customers in the next lowest order of priority category, and so on, until sufficient volumes have been curtailed to bring remaining requirements into balance with available system supply.

In the event that only a partial curtailment of total volumes in any category or sub-category is required and to the degree it is possible, such curtailment will be rotated among customers in each category from one curtailment period to the next to prevent any one customer in a certain category from being curtailed to a greater extent than other customers in that same category.

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

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

CURTAILMENT NOTICE

The Company shall give as much advance notice as possible for each curtailment order, but in no event will the Company provide less than two hours' notice unless prevented from doing so by force majeure conditions. In each curtailment order, the Company's curtailment and restoration notices, respectively, shall be given by telephonic communications, electronic communication, or personal contact by Company personnel to the customer's responsible representative and such order shall specify both the volumes to be curtailed and/or restored at the time that curtailment and/or restoration of customer's requirement is to be effective.

FIRM SERVICE BILLING ADJUSTMENT

The monthly bill for any firm service customer curtailed by the Company for a reason contained in this Rule shall be adjusted for the entire month in which curtailment occurred. The total amount due will be reduced by an amount equal to fifty percent of the difference between the amount of the gas bill for such month as determined under the Rate Schedule the customer's regular billings are rendered and the amount that the customer would have been billed that month per Schedule 170, Interruptible Service. Such billing adjustment shall be provided as a reduction of the customer's monthly billing for the month in which the curtailment was experienced. No billing adjustment will be made in the event curtailment of firm service by Company is necessary due to force majeure conditions as defined in Company's Rule 16.

(continued)

RULE 17
ORDER OF PRIORITY FOR GAS SERVICE

UNAUTHRORIZED USAGE CHARGES
A customer served on a transportation or interruptible rate, who uses more gas than the Company allows during a curtailment period, if any, will incur an overrun charge as established in the rate schedule under which that customer receives service.

FORCE MAJUERE
In the event it should become necessary to curtail service due to force majeure conditions, the Company may curtail without notice or without reference to the priorities established herein. *See* Rule 16.

COMPANY'S LIABILITY
The Company shall not be liable for damages or otherwise to any customer for failure to deliver gas that may be curtailed pursuant to this order of priority of firm service.

RULE 18
LIMITATION OF FIRM SERVICE

GENERAL
Firm service will be available to a customer if the Company determines, in its sole judgment, that adequate supply and capacity are available to accommodate a Customer's service requirements. If the Company determines firm service is not available to a customer, interruptible service may be an option.

RULE 19
CONSERVATION ALLIANCE PLAN MECHANISM

APPLICABLE
The Conservation Alliance Plan (CAP) mechanism described in this rule applies to customers served on Residential General Service Rate Schedule 101 and Commercial General Service Rate Schedule 104.

TERM
The Company shall initiate a review of this mechanism on September 30, 2019, with any proposed changes to be effective January 1, 2020.

PURPOSE
The purpose of this provision is to (a) define the procedures for the annual tracking revisions in rates due to changes in the weather-normalized use per customer associated with Rate Schedule 101 & Rate Schedule 104; and (b) to define the procedures for the deferral of differences experienced between the actual average use per customer and the amount estimated at the time the Margin Rates were established.

REVISIONS TO COMMODITY MARGIN RATES DUE TO CHANGES IN THE WEATHER-NORMALIZED USE/CUSTOMER

1. The Company shall use the baseline weather normalized average commodity margin per customer for Rate Schedule 101 and Rate Schedule 104 as reflected in its March 31, 2015, General Rate Case Filing (UG 287). That application was based upon the weather normalized twelve months ended December 31, 2015.

2. For each subsequent year for the term of this provision, the Company shall file annually (CAP Filing) with the Commission to update the Commodity Margin Rate for Rate Schedule 101 and Rate Schedule 104 based upon the weather normalized usage for the twelve months ending June 30th divided into the margin requirement of each rate schedule.

3. Weather-normalized usage is calculated using the approach to weather normalization adopted in the Company's Spring Earnings Review filings, PGA Applications and other weather normalized report submittals.

4. The Total Commodity Margin Requirement of Rate Schedule 101 and Rate Schedule 104 shall be calculated by multiplying the baseline average commodity margin per customer per Rate Schedule, excluding any margin collected through the monthly Basic Service Charge, by the current twelve months ended June 30 average customer count based upon the average of the monthly bills issued.

5. The Margin Commodity Rate is calculated by dividing the Total Commodity Margin Requirement by the Total Weather Normalized Usage.

RULE 19
CONSERVATION ALLIANCE PLAN MECHANISM

DEFERRAL OF MARGIN COLLECTION DIFFERENCES

1. The Company will maintain Conservation Variance and Weather Variance deferral accounts as Regulatory Assets or Liabilities. Each month, the Company will calculate the difference between the weather-normalized actual margin and the expected margin for rate schedules 101 and 104. Expected margin shall be the baseline average commodity per customer multiplied by the current customer count. The resulting dollar amount difference will be recorded in the Conservation Variance deferral account. The Company will also calculate the difference between non-weather normalized actual margin and the expected margin for rate schedules 101 and 104. The resulting dollar amount difference will be reduced by subtracting the dollar amount recorded in the Conservation Variance deferral account with the remainder recorded in the Weather Variance deferral account.

2. The Company shall impute interest on the deferred balances on a monthly basis utilizing the Commission establish deferral account interest rate.

3. The Company will include in the annual CAP filing a temporary adjustment amount designed to amortize any balance in the Conservation Variance and the Weather Variance deferral accounts. Temporary surcharges and/or refund increments will be applied to the Margin Commodity Rate over the following twelve months or any other appropriate amortization period.

SCHEDULE 31
PUBLIC PURPOSE CHARGE

PURPOSE
The purpose of this provision is to define the funding method for public purpose activities to be administered through one or more independent entities. Public purpose activities include, but may not necessarily be limited to, energy efficiency programs, market transformation and low-income conservation and bill assistance programs designed to benefit sales customers within Cascade Natural Gas's service territory in Oregon.

APPLICABLITY
The charge herein shall be applicable to rate schedules 101, 104, 105, 111, and 170.

ADJUSTMENT TO RATES
Effective February 1, 2016, a public purpose charge equal to 3.4% of current revenues, including customer service charges, in each month will be assessed as a line item on applicable bills. The level of the public purpose charge will be reviewed and revised as necessary based on periodic evaluation of public purpose funding needs.

The public purpose charge shall be allocated to specific separate accounts to fund the respective public purpose programs as follows:

- 3.15% will support energy efficiency programs administered by the Energy Trust of Oregon (Energy Trust).
- 0.25% will support low-income conservation and bill assistance activities.

SPECIAL TERMS AND CONDITIONS
1. 93% of the public purpose funds will be transferred to the Energy Trust. The Energy Trust will use the funds to design, promote and administer natural gas energy efficiency programs in accordance with agreements executed between Cascade and the Energy Trust.

2. 7% of the public purpose funds will be transferred to two internal program accounts and dispersed to Community Action Agencies (Agencies) for the purpose of adding or expanding low-income weatherization programs and bill assistance programs. 70% of the funding will be designated for low-income conservation programs, and the remaining 30% will be designated for bill payment assistance. The internal accounts shall accrue interest at the Company's currently effective authorized rate of return.

SCHEDULE 31
PUBLIC PURPOSE CHARGE

SPECIAL TERMS AND CONDITIONS (continued)

3. Each month, the Company will bill the public purpose charge on all rate schedule 101, 104, 105, 111, and 170 customers' bills. By the 20th of the month following the billing month, the Company will forward the amount of funds expected to be collected from billings issued for the prior calendar month, less a reserve for uncollectibles in an amount equal to Cascade's average percentage of net write-offs, to each fund administrator. Funds retained after the 20th of the month will earn interest at the Company's authorized rate of return until distributed to the fund administrators unless otherwise specified in an approved program or other agreement.

4. The Company, and any independent entity selected to administer public purpose programs under this Tariff, will report program results as directed by the Commission. Copies of all reports provided by the fund administrators to the Commission shall also be submitted to the Company for review.

5. All public purpose funds will be allocated only to programs that are available within the Company's Oregon service territory.

SCHEDULE 32
OREGON LOW INCOME ASSISTANCE PROGRAM

PURPOSE

The purpose of this provision is to define the mechanism for providing low-income bill assistance funding to the independent entities delivering the program and to define the process through which those funds will be allocated to the various entities providing services to low-income residential customers within Cascade Natural Gas's service territory in Oregon. This tariff schedule works in conjunction with Schedule 31 and Schedule 33.

GENERAL TERMS AND CONDITION

The monies provided by the public purpose funding, defined in Schedule 31, will be transferred to an internal program account and dispersed to Community Action Agencies (Agencies) for the purpose of adding or expanding low-income bill assistance and weatherization programs on a monthly basis.

SPECIAL TERMS AND CONDITIONS

1. In order to participate in the program, an Agency must be a legal entity, contracting or subcontracting with the State of Oregon, Department of Housing and Community Services (OHCS), which is eligible to administer funding under the Federal Low-Income Home Energy Assistance Program (LIHEAP).

2. All funds allocated to the Agencies will be distributed only to income-eligible residential customers of Cascade Natural Gas. Fund distribution will be accomplished using a cashless voucher system. The cashless voucher system will allow the transfer of authorized payments to an individual customer's utility account from the Oregon Low-Income Bill Assistance program account based on an electronic voucher list submitted to the company by each participating Agency. The company will process the voucher as soon as possible following receipt of the voucher list. In the event the Company receives a voucher authorization for a single customer from two or more Agencies, the Company will process only one voucher authorization.

3. The company will determine the allocation of bill assistance funds to the participating Agencies at the beginning of each program year based on the same allocation used by OHCS to allocate funds under LIHEAP during the previous program year, except that the finds may be reallocated at any time during the program year, if the company, at its sole discretion, determines that such a re-allocation is the most effective and efficient use of the available funds.

(continued)

RULE 32
OREGON LOW INCOME ASSISTANCE PROGRAM

SPECIAL TERMS AND CONDITIONS (conditions)

4. Each participating Agency will have sole responsibility to screen and approve applicants for eligibility. Each Agency shall follow the established protocols for the qualification of and disbursement to eligible participants in accordance with the guidelines promulgated by OHCS and the Low-Income Energy Assistance Act of 1981 and subsequent amendments, as outlined in the OHCS Omnibus Contract. The amount of assistance for eligible participants shall be based on the LIHEAP/OEA Poverty Guidelines and Payment Matrix from the OHCS/OEA Manual for these programs. Any voucher authorization received by the Company that exceeds these guidelines will be appropriately adjusted. If a customer has a credit balance due to the receipt of low-income assistance and the customer's service is disconnected, the credit balance will be redirected to the Agency's allocation fund for distribution to other clients.

5. Each Agency will be reimbursed from the Oregon Low-Income Bill Assistance Program account for certain administrative costs and direct program costs incurred by them in the administration and delivery of the program to Cascade's customers. Total program administration and delivery costs shall not exceed 20 percent of the total low-income bill payment assistance funds applied to customers' utility accounts. Should actual administrative and program delivery costs be lower than the 20 percent, the remaining funds shall be allocated into the program fund to support direct services.

6. Each Agency will provide a summary report providing information on the prior month's program activities. The report must identify the number of families assisted and their location, as well as the amount of funds dispersed. The Company must receive all reports by the 20th business day of each month.

7. The Bill Payment Program year will extend from October 1 through September 30. Any amounts not disbursed in the program year will carry over to the next program year. The Company will provide an annual summary evaluation report on the progress of the program for review by the Commission by December 1 following the end of each program year.

SCHEDULE 33
OREGON LOW-INCOME ENERGY CONSERVATION PROGRAM

PURPOSE
The purpose of this provision is to define the terms and conditions under which that portion of the funds designated for use for low-income weatherization programs under Schedule 31, Public Purpose Charge will be administered and delivered to eligible customers.

AVAILABLE
This program is available to income-eligible residential dwellings served by Cascade where the primary heating equipment in the residential dwelling is fueled by natural gas. Any residential dwelling that received assistance for the installation of the same or similar measures under any other energy efficiency program will not be eligible for assistance under this program.

PROGRAM DESCRIPTION
The Oregon Low-Income Energy Conservation (OLIEC) Program is a program designed to increase energy efficiency in low-income households within Cascade's service territory by providing rebates for the installation of certain weatherization and conservation measures in qualifying residential dwellings following the completion of a home energy evaluation performed by qualifying Low Income, 501c3, or Community Action Agencies (Agencies).

ENERGY EFFICIENCY MEASURES
The following energy efficiency measures qualify for rebates under this program:

Existing Low Income Residential Dwellings
- Ceiling, floor, wall and duct insulation
- Duct sealing (per Oregon Office of Energy standards)
- Infiltration system (weather stripping and caulking)
- High-efficiency furnace installations (90+ % efficient) where cost effective
- Furnace tune-up and filter replacement
- High-efficiency water heater (.62+ where the primary water heating source is natural gas)

New Low Income Residential Construction
The following energy efficiency measures applied toward the construction of affordable housing shall qualify for rebate if the project is designated primarily for the habitation of low income individuals and shall remain under a thirty year period of affordability. Qualified measures include:

- Energy Star Qualified Homes
- High-efficiency furnace installations (90+ % efficient) where cost effective
- High-efficiency water heater (.62+ where the primary water heating source is natural gas)

(continued)

SCHEDULE 33
OREGON LOW-INCOME ENERGY CONSERVATION PROGRAM

ENERGY EFFICIENCY MEASURES (continued)
New Low Income Residential Construction (continued)
The Company, at its discretion, will consider rebates for custom energy efficiency measures applied to new and existing low income dwellings on an individual basis with preference given for measures that would qualify for rebate in similar projects offered through the Energy Trust of Oregon (Energy Trust). An appropriate incentive payment for custom projects will be calculated as 80% of avoided therm cost based upon the therm savings of the gas efficiency measures that are installed at each project.

PROGRAM YEAR
The OLIEC Program year will extend from October 1 through September 30.

ANNUAL REPORT
By December 1, the Company will provide the Commission with an annual report detailing the number of homes treated and dollars spent in the prior program year.

CUSTOMER QUALIFICATIONS
All funds collected under this program will be distributed only to qualifying income-eligible residential customers of Cascade. In the event the Company receives a rebate request for a single customer from two or more Agencies, the Company will process only one rebate request.

FUNDS COLLECTED UNDER THIS PROGRAM ARE AVAILABLE AS FOLLOWS:
1. Beginning with the 2009-2010 program year and for each year thereafter, the Company will designate $25,000 of the program funds for use by Community Action Agencies (Agencies) and 501c3 non-profit agencies for custom low income energy efficiency (CEE) projects. This amount shall also be the designated fund to eligible 501c3 agencies not identified as Agencies for all energy conservation and retrofit measures. The Company will determine the allocation of remaining funds to participating Agencies at the beginning of each program year based on the same allocation used by Oregon Housing and Community Services (OHCS) to allocate funds under the Federal Low Income Home Energy Assistance Program (LIHEAP) during the previous program year. The Company will advise each Agency at the beginning of each program year of the amount the Company estimates will be available to each Agency in that year.

2. In the Company's sole discretion, funds may be re-allocated among the Agencies at any time during the program year whenever the Company determines that such a re-allocation is the most effective and efficient use of the available funds. The Company will not make any such re-allocation without first providing advance notice to the affected Agencies.

3. Any amounts not disbursed in the program year will carry over to the next program year.

(continued)

SCHEDULE 33
OREGON LOW-INCOME ENERGY CONSERVATION PROGRAM

AGENCY QUALIFICATIONS AND RESPONSIBILITIES

1. In order to participate in the program, an Agency must be a legal entity, contracting or subcontracting with the State of Oregon, Department of Housing and Community Services (OHCS), which is eligible to administer funding under the Federal Low Income Home Energy Assistance Program (LIHEAP). An agency shall also qualify to participate in the program if it is a state-recognized Low Income Agency or 501c3 nonprofit engaged in the construction or retrofit of affordable housing designated primarily for the habitation of low income individuals.

2. Each participating Agency will have sole responsibility to screen and approve applicants for eligibility. Each Agency shall follow the established protocols for the qualification of and disbursement to eligible participants in accordance with the guidelines promulgated by OHCS. Agencies operating the Weatherization Assistance Program shall complete their work in accordance with the Low-Income Energy Assistance Act of 1981 and subsequent amendments, as outlined in the OHCS Omnibus Contract. The Company reserves the right to verify installation and compliance with all state codes and standards prior to payment of any rebates.

3. Each participating Agency shall be responsible to complete and return to the Company all required paperwork and other documentation as may be necessary for the Company to process the rebate request. The Company will provide the documentation forms to each participating Agency in electronic or hard copy form, whichever is requested. At a minimum, the documentation must include the Agency name, customer name, the landlord name and address, if applicable, the address of the qualifying households, the square footage of the home, a list of the measures installed, the rebate amount per measure, and total rebate per household.

REBATE PAYMENTS

1. The Company will reimburse participating Agencies for the installation of qualifying measures installed in each eligible household based on the table shown below.

2. In no event will any rebate amount be greater than the actual installed cost of the measure.

3. Qualified measures are eligible for rebate in the amount of 100% of avoided therm cost or 100% of the installed cost of the measure, whichever is less. Custom projects for new low income construction shall be eligible for a rebate of 80% of avoided therm cost. Avoided therm cost shall reflect the Company's most recently acknowledged IRP document.

(continued)

SCHEDULE 33
OREGON LOW-INCOME ENERGY CONSERVATION PROGRAM

REBATE PAYMENTS (continued)

Measure	Therm Savings Factor Per Square Foot	Avoided Cost Per Therm	Rebate per Home
Install ceiling insulation where no ceiling insulation exists	0.088	$11.66	Therm savings factor x square footage x avoided cost per therm
Install ceiling insulation where ceiling insulation <R-12 exists	0.034	$11.66	Therm savings factor x square footage x avoided cost per therm
Install floor insulation	0.052	$11.66	Therm savings factor x square footage x avoided cost per therm
Install wall insulation	0.074	$11.66	Therm savings factor x square footage x avoided cost per therm
	Therm savings factor per linear foot		
Install duct insulation	0.136	$9.21	(Therm savings factor x square footage)/(square footage x average linear ft of ductwork per sq ft) x avoided cost per therm
Install duct sealing	--	--	$810
Install infiltration measures	--	--	$120
Install high-efficiency (90%+) furnace	--	--	$690
Install direct vent spaceheater	--	--	$396
Perform furnace tune-up	--	--	$65
High efficiency water heater (.62)*	--	--	$85
Energy Star qualified homes	--	--	$1,107

* Hot water measures shall only be installed in homes where the primary heating source for water is natural gas.

PROGRAM ADMINISTRATION AND DELIVERY COSTS

1. Each Agency will be reimbursed from the Low-Income Weatherization account for administrative costs and direct program costs incurred by it in its administration and delivery of the OLIEC Program in the amount of $225 per household. The Agency fee will be paid to each Agency along with each rebate payment. The Company will process rebates and Agency payments within thirty days from the date the Company receives all completed documentation in support of such rebate requests.

2. The Company will be reimbursed for actual first year program set-up costs from the OLIEC account in an amount not to exceed $5,000.

3. The Company will be reimbursed from the OLIEC account each month for actual program administration costs incurred, except that such reimbursement will not exceed 5% of the total available funds collected during each program year.

(continued)

SCHEDULE 33
OREGON LOW-INCOME ENERGY CONSERVATION PROGRAM

PROGRAM EVALUATION

1. The Company will have a program baseline assessment performed as soon as practical following the effective date of this Schedule.

2. An Advisory Group will be formed to assist the Company in low-income weatherization and bill assistance program development, implementation, and evaluation. The Advisory Group will consist of at least one member each from the Company, the Commission staff, The Community Action Directors of Oregon (CADO) and from two or more participating Agencies.

3. Following the end of program year, the Company will arrange for an independent program performance evaluation to be paid from Low-Income Weatherization funds identified in Schedule 31 in an amount not to exceed $25,000 per year.

4. The Company will use the Advisory Group process and the independent program evaluation results to modify the program structure and process, where appropriate. These processes may also be used to assess whether or not any change to low-income weatherization and bill payment assistance funding levels is appropriate.

(continued)

SCHEDULE 33
OREGON LOW-INCOME ENERGY CONSERVATION PROGRAM
CONSERVATION ACHIEVEMENT TARIFF (CAT) PILOT PROGRAM

PROGRAM DESCRIPTON

The Conservation Achievement Tariff (CAT) is a pilot program in effect until December 31, 2017. The CAT operates alongside of, and in conjunction, with the existing Oregon Low-Income Energy Conservation (OLIEC) Program which is defined previously in this Schedule. This provision defines the terms and conditions under which funds designated for low-income energy conservation programs under Schedule 33 is administered and delivered to eligible residential customers within Cascade Natural Gas' service territory in Oregon.

At its sole discretion, the Company may allocate funds collected under Schedule 31, Public Purpose Funding for low income energy conservation programs to a separate pool (CAT pool) if funding for OLIEC is sufficient to meet the needs of agencies qualified to provide weatherization services to Cascade customers under the OLIEC Schedule 33. CAT funding may be accessed by any of the qualifying Low-Income, 501c3 or Community Action Agencies (Agencies) that administer the OLIEC program for the purpose of providing programmatic funding for the completion and performance of qualified weatherization work authorized through the OLIEC tariff. The intent of this tariff is to provide essential monies to bridge the gap between the Company's payments associated with customer energy savings via the traditional OLIEC program and the funds necessary for full delivery of this essential program to qualified customers. The funds are available to Agencies on a first come, first serve basis for the purpose of providing Total Installed Costs for weatherization measures approved under Schedule 33, Oregon Low Income Energy Conservation (OLIEC) program.

"Total Installed Costs" are defined as all costs incurred for materials and contractor labor necessary to fully perform tariff-eligible natural gas weatherization work at a qualified customer premise. In order to qualify for CAT funding, the participating Agency shall provide all associated invoices and receipts as evidence of expenditures for authorized weatherization work provided to the Company for validation.

Monies may be directed from OLIEC to the CAT fund during the course of the program year at the Company's sole discretion, whenever the Company determines that such a reallocation is the most effective and efficient use of available funds. The Company will not make any such re-allocation without first providing advance notice to the affected Agencies.

All measures currently defined as eligible under OLIEC shall be eligible for funds to cover Total Installed Costs under CAT. In the event that additional measures become eligible for funding under the OLIEC, the CAT shall also apply.

(continued)

SCHEDULE 33
OREGON LOW-INCOME ENERGY CONSERVATION PROGRAM
CONSERVATION ACHIEVEMENT TARIFF (CAT) PILOT PROGRAM

PROGRAM DESCRIPTION (continued)

Agencies that complete projects under OLIEC, and install one or more of the eligible energy efficiency measures, are eligible to receive their normal reimbursement under that program. Agencies are also eligible to receive an additional CAT allocation that equates to the difference between the OLIEC rebate for each eligible measure installed and the invoiced amount for the Total Installed Cost of each measure. These monies shall be available upon receipt of documentation verifying the final incremental costs between those covered under the traditional OLIEC program and the remaining Total Installed Costs.

PROGRAM ADMINISTATION AND DELIVERY COSTS

The OLIEC program will remain a separate low-income energy conservation program. The CAT program is a pilot program that operates in conjunction with OLIEC. The OLIEC program contains a listing of program administration and delivery costs. There are no additional program administration and delivery costs associated with the Conservation Achievement Tariff.

ANNUAL REPORT

The annual OLIEC report will contain information on CAT including but not be limited to, number of participants and total cost of CAT.

SCHEDULE 34
ENERGY EFFICIENCY SERVICES AND PROGRAMS

PURPOSE
This provision is intended to provide an economical and effective means of conserving natural gas through the reduction of heat loss in residential dwellings, and commercial and industrial buildings and in the improvement of the efficiency of space heating, water heating, and energy utilization of the dwellings.

AVAILABLE
This program is available to all customers served on Schedules 101, 104, 105, 111, and 170.

INFORMATION TO CUSTOMERS
The Company will provide applicable customers with general and technical information about energy efficiency services and about energy efficiency programs available through the Energy Trust of Oregon (Energy Trust) that will improve the efficiency of space heating and energy utilization of residential dwellings and commercial/industrial facilities. This information may be provided through bill inserts, displays (all offices), booklets, handouts, advertisements, and industry and public agency literature.

ENERGY EFFICIENCY PROGRAMS
The Energy Trust has been approved to deliver and administer energy efficiency programs to Cascade's customers. Customers may participate in such programs by contacting the Energy Trust directly or a Cascade representative, who will connect the customer upon request.

CUSTOMER NOTIFICATION
Sales customers will be notified annually by bill insert: (1) that information on energy efficiency is available from the Company; (2) that energy efficiency programs are available through the Energy Trust; (3) how to obtain energy efficiency information from the Company; and (4) how to contact the Energy Trust.

Notification to rental unit owners will be made by mail when a tenant who is a customer requests the material be mailed to the owner; and furnishes the owner's name and address with the request.

GENERAL TERMS
This Schedule is governed by the terms of this Schedule, the General Rules and Regulations contained in this Tariff and by all rules and regulations prescribed by regulatory authorities, as amended from time to time.

SCHEDULE 100
ADJUSTMENT FOR MUNICIPAL EXACTIONS

APPLICABILITY
This schedule sets forth the conditions under which exactions such as license, privilege, franchise, business, occupation, operating, excise, sales or use of street taxes or other exactions now imposed, or which may hereafter be imposed on the Company are billed by the Company to its customers.

TERRITORY
This schedule is applicable to all customers in the entire territory in the State of Oregon served by the Company.

RATES AND CONDITIONS
When any municipal corporation or other local taxing agency imposes on the Company any license, privilege, franchise, business, occupation, operating, excise, sales or use of street taxes or exactions, the amount thereof which exceeds 3% of the gross revenue derived from gas service furnished customers within the levying municipality or taxing district, the excess above 3% shall be billed pro rata to such customers in accordance with OAR 860-022-0040(1) as approved by the Public Utility Commission of Oregon. When customers are billed as herein provided, the amount will be separately stated on, and added to, the regular billing.

SCHEDULE 101
GENERAL RESIDENTIAL SERVICE RATE

APPLICABILITY
This schedule is available to residential customers.

RATE

Basic Service Charge		$3.00	per month
Delivery Charge	all therms per month	$0.40656	per therm
Schedule 177	Cost of Gas (WACOG)	$0.49633	per therm
Schedule 191	Gas Cost Rate Adjustment	($0.02361)	per therm
Schedule 192	Intervenor Funding Adjustment	$0.00102	per therm
Schedule 193	Conservation Alliance Plan Mechanism	$0.01035	per therm
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm
	Total	$0.89065	per therm

MINIMUM CHARGE
Basic Service Charge $3.00

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

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

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

SCHEDULE 104
GENERAL COMMERCIAL SERVICE RATE

APPLICABILITY
This schedule is available to commercial customers.

RATE

Basic Service Charge		$3.00	per month
Delivery Charge	all therms per month	$0.26263	per therm
Schedule 177	Cost of Gas (WACOG)	$0.49633	per therm
Schedule 191	Gas Cost Rate Adjustment	($0.02361)	per therm
Schedule 192	Intervenor Funding Adjustment	$0.00000	per therm
Schedule 193	Conservation Alliance Plan Mechanism	$0.01035	per therm
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm
	Total	$0.74570	per therm

MINIMUM CHARGE
Basic Service Charge $3.00

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

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

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

SCHEDULE 105
GENERAL INDUSTRIAL SERVICE RATE

APPLICABILITY
This schedule is available to industrial customers.

RATE

Basic Service Charge		$30.00	per month
Delivery Charge	all therms per month	$0.24458	per therm
Schedule 177	Cost of Gas (WACOG)	$0.49633	
Schedule 191	Gas Cost Rate Adjustment	($0.02361)	per therm
Schedule 192	Intervenor Funding Adjustment	$0.00006	
Schedule 193	Decoupling Mechanism Adjustment	$0.00000	per therm
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm
	Total	$0.71736	per therm

MINIMUM CHARGE
Basic Service Charge $30.00

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

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

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

SCHEDULE 111
LARGE VOLUME GENERAL SERVICE RATE

APPLICABILITY

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

RATE

Basic Service Charge		$200.00	per month
All Therms per Month:			
Delivery Charge		$0.17436	per therm
OTHER CHARGES:			
Schedule 177	Cost of Gas (WACOG)	$0.49633	per therm
Schedule 191	Gas Cost Rate Adjustment	($0.02361)	per therm
Schedule 192	Intervenor Funding Adjustment	$0.00006	per therm
Schedule 193	CAP Temporary Adjustment	$0.00000	per therm
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm
	Total	$0.64714	per therm

MINIMUM CHARGE

Basic Service Charge $200.00

CONTRACT

Customers receiving service under this rate schedule shall execute a contract for a minimum period of twelve consecutive months' use. The Annual Minimum Quantity is to be negotiated and included as part of the contract but in no case shall the Annual Minimum Quantity be less than 50,000 therms.

ANNUAL DEFICIENCY BILL

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

(continued)

SCHEDULE 111
LARGE VOLUME GENERAL SERVICE RATE

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 112
COMPRESSED NATURAL GAS SERVICE

AVAILABILITY
This schedule is available for the sole purpose of compressing natural gas for use as a fuel in vehicular internal combustion engines. Service under this schedule shall be through one or more meters, at the option of the Company, provided they are located on contiguous property not divided by streets, roads, alleys, or other public thoroughfares. Service for any end use of natural gas other than the compression of natural gas for vehicle use, such as space heating, water heating, or any other direct processing or boiler fuel use, is not permitted under this rate schedule or through the meter through which service under this rate schedule is offered.

RATE

Basic Service Charge		$3.00	per month
All Therms Per Month:			
Delivery Charge		$0.22600	per therm
OTHER CHARGES:			
Schedule 177	Cost of Gas (WACOG)	$0.49633	per therm
Schedule 191	Gas Cost Rate Adjustment	($0.02361)	per therm
Schedule 192	Intervenor Funding Adjustment	$0.00000	per therm
Schedule 193	CAP Temporary Adjustment	$0.00000	per therm
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm
	Total	$0.69872	per therm

MINIMUM CHARGE
Basic Service Charge $3.00

CONTRACT
Customers receiving service under this rate schedule shall sign a contract having a minimum term of twelve months. Said contract shall contain such provisions regarding indemnification and insurance as the Company deems necessary or desirable with respect to a particular customer.

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

(continued)

SCHEDULE 112
COMPRESSED NATURAL GAS SERVICE

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 126
EMERGENCY INSTITUTIONAL SERVICE

AVAILABILITY
This schedule is available upon written application wherein the customer makes a showing acceptable to Company demonstrating the customer's institutional operations could not be continued without severe disadvantage to the occupants of customer's facilities in the absence of service under this schedule.

APPLICABILITY
To institutional customers currently taking service from the Company under its filed rate schedules.

CONTRACT
Customers receiving service under this rate schedule shall execute a contract for a period of twelve consecutive months.

RATE

All Therms per Month:			
Delivery Charge		$0.26670	per therm
OTHER CHARGES:			
Schedule 177	Cost of Gas (WACOG)	$0.49633	per therm
Schedule 191	Gas Cost Rate Adjustment	($0.02361)	per therm
Schedule 192	Intervenor Funding Adjustment	$0.00000	per therm
Schedule 193	Conservation Alliance Plan Mechanism	$0.00000	per therm
Schedule 195	Public Purposes Charge	$0.00000	per therm
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm
	Total	$0.73942	per therm

MINIMUM CHARGE
None

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.

(continued)

SCHEDULE 126
EMERGENCY INSTITUTIONAL SERVICE

CURTAILMENT
Service under this schedule is subject to curtailment as established in Rule 17. If the customer uses any amount of gas above the amount authorized by the Company during a curtailment event, the customer's failure to comply with the Company's curtailment order shall be considered as an unauthorized overrun volume. The customer shall incur an unauthorized overrun charge of $0.50 per therm; this charge is in addition to the regular charges incurred in the Rate section of this schedule. The payment of an overrun penalty shall not under any circumstances be considered as giving customer the right to take unauthorized overrun gas or to exclude any other remedies which may be available to the Company to prevent such overrun.

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 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, curtailment and pre-emption (all of which are defined below in this schedule).

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** $750.00 per month

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

		Base Rate	Sch. 192	Sch. 196	Billing Rate	
First	10,000	$0.12909	$0.00006	$0.00000	$0.12915	per therm
Next	10,000	$0.11645	$0.00006	$0.00000	$0.11651	per therm
Next	30,000	$0.10941	$0.00006	$0.00000	$0.10947	per therm
Next	50,000	$0.06720	$0.00006	$0.00000	$0.06726	per therm
Next	400,000	$0.03409	$0.00006	$0.00000	$0.03415	per therm
Over	500,000	$0.01827	$0.00006	$0.00000	$0.01833	per therm

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 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

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

Customers electing to provide their own gas supplies under this schedule in lieu of firm system supply waive any right to automatically purchase firm supplies at some future date. Requests for firm service shall be subject to the effects on service availability or costs to other customers and may require a charge to offset any incremental costs of acquiring additional firm supplies.

Service under this Schedule is subject to entitlement, curtailment and pre-emption as defined below:
1) Entitlement. During an entitlement, a customer served on this Schedule is required to control gas usage to be within a specified threshold percentage as determined by the Company. A customer who fails to comply with an entitlement order will incur additional charges, as established below in this Schedule.
2) Curtailment. A curtailment is when the Company must interrupt any or all of the service to customers, in accordance with the term and conditions established in Rule 17. A curtailment event may affect any level of service depending on the severity and geographical scope of the event. A Customer who fails to comply with a curtailment order will incur additional charges as established below in this Schedule; and
3) Pre-emption. Pre-emption is when a customer served under this schedule is required to make its gas available to the Company for a price, to the extent the Company determines it is necessary to maintain service to customers with higher service priorities as defined in Rule 17.

SERVICE CONTRACT
Service under this schedule requires an executed contract between the Company and the customer.

A. Contract Term
The contract term shall be for a period not less than the period covered under the customer's gas purchase contract with customer's supplier. However, in no event shall the contract be for less than one year and the termination date of the contract in any year shall be September 30th.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

SERVICE CONTRACT (continued)

B. Required Content
   1. The service contract shall state the annual minimum quantity of gas to be delivered;
   2. The service contract shall state the maximum daily volume of gas to be delivered under this distribution system capacity schedule; and
   3. The annual minimum charge is to be negotiated and included as part of contract between Company and customer, and may be in addition to amounts otherwise due under this schedule.

GAS SUPPLY

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

SUPPLIER AND RELATED RESPONSIBILITIES

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

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

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

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

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

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

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

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

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

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

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

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

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

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

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

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

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

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

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

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

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

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

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

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

PRIORITY OF NOMINATED GAS (continued)

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

PRE-EMPTION

In the event the Company is required to curtail firm service customers the Company may automatically assign gas supply from Schedule 163 customers to priority 1 and 2 customers as defined in Rule 17.

In the event of such re-assignment, the Company shall compensate affected customers served under this Schedule with a credit equal to the then current Cascade WACOG commodity rate for all volumes assigned plus a penalty credit of $0.60 per therm on all but the first 5% of customer's daily entitlement under this schedule.

UNAUTHORIZED USE OF GAS DURING CURTAILMENTS OR ENTITLEMENT PERIODS

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

- **Underrun Entitlement** - A condition whereby a customer served under this schedule is required to use the gas previously nominated and received on such Customer’s behalf on a specified gas day.
- **Overrun Entitlement -** A condition whereby a customer served under this Schedule is restricted to use no more than a percentage of such customer’s acknowledged confirmations on a specified gas day.

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

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

In the event of failure of customer's supplies or if capacity is pre-empted for service entitled to higher priority customers (as defined in Rule 17), the Company may curtail deliveries to the customer or issue a system entitlement. Customer usage of gas above the amount authorized by the Company during an entitlement period shall be considered an unauthorized overrun volume. The overrun charge that will be applied during any overrun entitlement period will equal the greater of $1.00 per therm or 150% of the highest midpoint price for the day at NW Wyoming Pool, NW south of Green River, Stanfield Oregon, NW Canadian Border (Sumas), Kern River Opal, or El Paso Bondad supply pricing points (as published in Gas Daily), converted from dollars per dekatherms to dollars per therm by dividing by ten. The overrun charge will be in addition to the incremental costs of any supplemental gas supplies the Company may have had to purchase to cover such unauthorized use, in addition to the regular charges incurred in the Rate section of this Schedule and any other charges incurred per the terms and conditions established in this Schedule. The payment of an overrun penalty shall not under any circumstances be considered as giving customer the right to take unauthorized overrun gas or to exclude any other remedies which may be available to the Company to prevent such overrun. The charge that will apply during any underrun entitlement period will be $1.00 per therm for any underrun imbalances.

NOTICE OF CURTAILMENT, ENTITLEMENT, OR PRE-EMPTION
The Company shall give as much advance notice as possible for each curtailment, entitlement, or pre-emption order (generally referred to in this Section as curtailment), but in no event will the Company provide less than two hours' notice unless prevented from doing so by Force Majeure conditions. The Company's curtailment and restoration notices, respectively, shall be given by telephonic communications, electronic communication, or personal contact by Company personnel to the customer's responsible representative, and such order shall specify both the volumes to be curtailed and/or restored at the time that curtailment and/or restoration of customer's requirement is to be effective.

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

(continued)

SCHEDULE 163
GENERAL DISTRIBUTION SYSTEM INTERRUPTIBLE TRANSPORTATION SERVICE

GENERAL TERMS

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

SCHEDULE 170
INTERRUPTIBLE SERVICE

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

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

RATE

Basic Service Charge		$300.00	per month
All Therms per Month:			
Delivery Charge		$0.11719	per therm
OTHER CHARGES:			
Schedule 177	Cost of Gas (WACOG)	$0.49633	per therm
Schedule 191	Gas Cost Rate Adjustment	($0.02361)	per therm
Schedule 192	Intervenor Funding Adjustment	$0.00006	per therm
Schedule 193	Decoupling Mechanism Adjustment	$0.00000	per therm
Schedule 196	Oregon Earnings Sharing	$0.00000	per therm
All Therms per Month:	Total Per Therm Rate	$0.58997	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.

CONTRACT
Customers receiving service under this rate schedule shall execute a contract for a minimum period of twelve consecutive months' use. This contract shall state the maximum daily consumption of natural gas that Company agrees to deliver, as well as the annual minimum quantity.

(continued)

SCHEDULE 170
INTERRUPTIBLE SERVICE

ANNUAL DEFICIENCY BILL
In the event a customer purchases less than the annual minimum quantity, as defined in the contract, the customer shall be charged an Annual Deficiency Bill. Annual Deficiency Bill shall be calculated by multiplying the difference between the Annual Minimum Quantity and the therms actually taken (Deficiency Therms) times the difference between the commodity rate in this Rate Schedule 170, as modified by any applicable rate adjustments, and the weighted average commodity cost of system supply gas as such costs are reflected in the Company's tariffs. If the Company curtailed or interrupted service, the Annual Minimum Quantity shall be reduced by a fraction, the numerator of which is the actual number of days or fraction thereof, service was curtailed and the denominator of which is 365.

CURTAILMENT
Service under this schedule is subject to curtailment as established in Rule 17. Customer usage of gas above the amount authorized by the Company during a curtailment period shall be considered an unauthorized overrun volume. The overrun charge that will be applied during any overrun entitlement period will equal the greater of $1.00 per therm or 150% of the highest midpoint price for the day at NW Wyoming Pool, NW south of Green River, Stanfield Oregon, NW Canadian Border (Sumas), Kern River Opal, or El Paso Bondad supply pricing points (as published in "Gas Daily"), converted from dollars per dekatherms to dollars per therm by dividing by ten. The overrun charge will be in addition to the incremental costs of any supplemental gas supplies the Company may have had to purchase to cover such unauthorized use, in addition to the regular charges incurred in the Rate section of this Schedule and any other charges incurred per the terms and conditions established in this Schedule. The payment of an overrun penalty shall not under any circumstances be considered as giving customer the right to take unauthorized overrun gas or to exclude any other remedies which may be available to the Company to prevent such overrun. The charge that will apply during any underrun entitlement period will be $1.00 per therm for any underrun imbalances.

ESSENTIAL AGRICULTURAL AND HGH PRIORITY USE
Service under this schedule is not available to an essential agricultural user or a high priority user, as defined in Rule 2.

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

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

SCHEDULE 177
PURCHASED GAS COST ADJUSTMENT PROVISION

APPLICABLE
This schedule applies to all schedules for natural gas sales service within the entire territory served by the Company in the State of Oregon. The definitions and provisions described herein shall establish the natural gas costs for Purchased Gas Adjustment (PGA) deferral purposes on a monthly basis.

PURPOSE
The purpose of this provision is to allow the Company, on established Adjustment Dates, to adjust rate schedules for changes in the cost of gas purchased in accordance with the rate adjustment provisions described herein.

ADJUSTMENT DATES
The Adjustment Date shall be November 1 of each year for changes in annual gas costs. The Company may file out-of-cycle PGA adjustments to be effective at times other than November 1 of each year, if the sum of the Company's annual Actual Commodity Costs and Actual Non-Commodity Costs differs from the sum of the annual Embedded Commodity Costs and Embedded Non-Commodity Costs by 10 percent or more, or for such other reasons and on such terms as the Commission may approve.

DEFINITIONS
1. Actual Commodity Cost: The natural gas supply costs for commodity actually paid for the month, including Financial Transactions, fuel use, and distribution system lost and unaccounted for natural gas (LUFG) plus Gas Storage Facilities withdrawals, plus or minus the cost of natural gas associated with pipeline imbalances, plus propane costs, plus odorization charges, less Commodity Off-System Sales Revenues received during the month, plus actual Variable Transportation Costs, plus commodity-related reservation charges, less all transportation demand charges embedded in commodity costs.

2. Commodity Off-System Sales Revenues: Revenues received from the sale of natural gas to a party other than the Company's Oregon sales customers less costs associated with the sales transactions.

3. Variable Transportation Costs: Variable transportation costs, including pipeline volumetric charges, and other variable costs related to volumes of commodity delivered to sales customers.

4. Actual Non-Commodity Cost: Actual Non-Commodity gas costs shall be equal to actual Demand Costs, less actual Capacity Release benefits, plus or minus actual pipeline refunds or surcharges.

5. Demand Costs: Fixed monthly pipeline costs and other demand-related natural gas costs such as capacity reservation charges, plus any transportation demand charges embedded in commodity costs.

(continued)

SCHEDULE 177
PURCHASED GAS COST ADJUSTMENT PROVISION

DEFINITIONS (continued)

6. Capacity Release Benefits: This component includes revenues associated with pipeline capacity releases. The benefits to customers, through the monthly PGA deferrals, shall be 100% of the capacity release revenues up to the full pipeline rate, and 80% of the capacity release revenues in excess of full pipeline rates. Capacity release revenues shall be quantified on a transaction-by-transaction basis.

7. Estimated Weighted Average Cost of Gas (WACOG): The estimated WACOG for the period November 1st through October 31st is calculated by the following formula: (Forecasted Purchases at Adjusted Contract Prices) divided by (forecasted sales volumes). This WACOG does not include any revenue sensitive factors.
   a. Forecasted Purchases means this year's forecasted sales volumes plus a percentage for distribution system LUFG and pipeline fuel in kind.
   b. Distribution system embedded LUFG means the 5-year average of actual distribution system LUFG, not to exceed 2%.
   c. Adjusted contract prices means actual and projected contract prices that are adjusted by each associated Canadian pipeline's published (closest to August 1) fuel use and line loss amount provided for by tariff, and by each associated U.S. pipeline's tariffed rate.

8. Estimated Non-Commodity Cost: Estimated annual Non-Commodity gas costs shall be equal to estimated annual Demand Costs, less estimated annual Capacity Release Benefits, plus or minus estimated annual pipeline refunds or surcharges.

9. Estimated Non-Commodity Cost per Therm: The Estimated Non-Commodity cost per therm is calculated by the following formula: (Estimated annual Non-Commodity Cost divided by forecasted sales volumes). This estimate does not include any revenue-sensitive factors.

The Estimated Cost of Gas per therm is as follows:

	Cost of Gas Per Therm	Revenue Sensitive Costs	Cost of Gas Per Therm Rate
WACOG	$0.29780	2.856%	$0.30655
Non-Commodity Cost	$0.18436		$0.18978
TOTAL	**$0.48216**	**2.856%**	**$0.49633**

10. Actual Monthly Calendar Sales Volumes: Actual billed sales therms, adjusted for estimated unbilled therms, for firm and interruptible sales schedules.

(continued)

SCHEDULE 177
PURCHASED GAS COST ADJUSTMENT PROVISION

DEFINITIONS (continued)

11. Embedded Commodity Cost: The Estimated WACOG multiplied by the Actual Monthly Calendar Sales Volumes.

12. Embedded Non-Commodity Cost: The Estimated Non-Commodity Cost per Therm multiplied by the Actual Calendar Sales Volumes less interruptible sales volumes.

13. Financial Transactions: Cost of Financial Transactions related to gas supply, including but not limited to, hedges, swaps, puts, calls, options and collars that are exercised to provide price stability/control or supply reliability for sales service customers.

14. Gas Storage Facilities: The cost of natural gas for injections shall be the actual cost of purchasing gas for storage and the cost of injection of the gas into the storage facility. Withdrawals of natural gas shall be valued at the weighted average cost of gas in the facility plus any variable withdrawal costs. Only the cost of natural gas withdrawn from Gas Storage Facilities will be included in the Actual Commodity Cost, as defined herein.

CALCULATION OF MONTHLY GAS COST FOR DEFERRAL PURPOSES

The Company will maintain sub-accounts OF Account 191. Monthly entries into these sub-accounts shall be made to reflect the differences between: 1) the monthly Actual Commodity Cost and the monthly Embedded Commodity Cost, and 2) the monthly Actual Non-Commodity Costs and the monthly Embedded Non-Commodity Cost. The entries shall be calculated as follows:

1. A debit or credit entry shall be made equal to 100% of the difference between the Actual Non-Commodity Cost and the Embedded Non-Commodity Cost.

2. A debit or credit entry shall be made equal to 90% of the difference between the Actual Commodity Costs and the Embedded Commodity Costs.

3. Differentials shall be deemed to be positive if the actual cost exceeds embedded costs and to be negative if actual costs fall below embedded costs.

4. The cost differential entries shall be debited to the Account 191 sub-accounts if positive, and credited to the Account 191 sub-accounts if negative.

5. Interest: The Company shall compute interest on deferred balances on a monthly basis using the interest rate(s) approved by the Commission.

(continued)

SCHEDULE 177
PURCHASED GAS COST ADJUSTMENT PROVISION

AMORTIZATION OF ACCOUNT 191 SUB-ACCOUNT DEFERRALS
The Account 191 sub-account balances shall be amortized over the twelve month period commencing with the November 1 adjustment date or such other time period acceptable to the Company and the Commission. The amount of amortization for the Account 191 sub-accounts shall consist of an amount necessary to recover or return the amount accumulated in the sub-accounts and other deferral accounts.

TIME AND MANNER OF FILINGS
Applications must be made no later than sixty days in advance of the effective date.

AMOUNT OF ADJUSTMENT
The amount of adjustment to be made to customers' rates effective on each November 1 adjustment date shall consist of the sum of the changes in the Embedded Commodity Cost and Non-Commodity Cost and the change in amortization rates of the PGA Balancing Accounts as well as other deferral accounts as the Commission may approve.

GENERAL TERMS
This schedule is subject to the General Rules and Regulations contained in this tariff and to those prescribed by regulatory authorities. This schedule is an automatic adjustment clause as described in ORS 757.210(1) and is subject to the customer notification requirements as described in OAR 860-022-0017.

SCHEDULE NO. 191
TEMPORARY GAS COST RATE ADJUSTMENT

APPLICABLE
The temporary rate applies to Schedules 101, 104, 105, 111, 112, 126, and 170.

RATES
Each of the charges specified in the schedules for gas service hereinafter listed shall be adjusted by the following per therm increase or (decrease) or appropriate multiple thereof in determining annual minimum bill, if any:

Rate Schedule	Amount
101	($.02361)
104	($.02361)
105	($.02361)
111	($.02361)
112	($.02361)
126	($.02361)
170	($.02361)

LIMITATION
This temporary rate adjustment shall remain in effect until cancelled pursuant to a Commission order.

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for 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 NO. 192
INTERVENOR FUNDING ADJUSTMENT

APPLICABLE
Applicable to customers served on Schedules 101, 104, 105, 111, 112, 126, 163, and 170.

PURPOSE
The purpose of this schedule is to recover the cost of Intervenor Funding Grants provided to various entities to cover their costs of advocating on behalf of customers. The awarding of such grants is governed by Section 7.3 of the First Amended and Restated Intervenor Funding agreement adopted by the Public Utility Commission of Oregon in Order No. 07-564.

MONTHLY RATES, MINIMUM BILLS AND OTHER CHARGES
Each of the charges specified in the schedules for gas service hereinafter listed shall be adjusted by the following per therm increase or (decrease) or appropriate multiple thereof:

Rate Schedule	Amount
101	$.00102
104	$.00000
105	$.00006
111	$.00006
112	$.00000
126	$.00000
163*	$.00006
170	$.00006
*all rate blocks	

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for 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 193
CONSERVATION ALLIANCE PLAN ADJUSTMENT

APPLICABLE
This rate applies to Schedules 101 and 104.

PURPOSE
The purpose of this schedule is to amortize deferred conservation and weather variances associated with the Company's approved conservation alliance plan as outlined in Rule 19 of the Company's tariff.

RATES
Each of the charges specified in the schedules for gas service hereinafter listed shall be adjusted by the following per therm increase or decrease or appropriate multiple thereof in determining annual minimum bill, if any:

Rate Schedule	Rate
101	$0.01035
104	$0.01035

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

TAX ADDITIONS
The rates named herein are subject to increases as set forth in Schedule 100 for 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 196
UM 903 OREGON EARNINGS SHARING

APPLICABLE
This temporary rate addition applies to gas service rendered by the Company under the tariff of which this schedule is a part for service on and after the effective date hereof and shall be in addition to all rates and charges specified in this tariff.

PURPOSE

This schedule refunds a portion of the Company's overearnings in accordance with the Commission's annual order issued in Docket No. UM 903.

RATES:

Each of the charges specified in the schedules for gas service hereinafter listed shall be adjusted by the following per therm increase or (decrease) or appropriate multiple thereof in determining annual minimum bill, if any:

Rate Schedule	Rate
101	$0.000
104	$0.000
105	$0.000
111	$0.000
163	$0.000
170	$0.000

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

SPECIAL TERMS AND CONDITIONS:

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

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

SCHEDULE 200
VARIOUS MISCELLANEOUS CHARGES

APPLICABILITY

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

I. Reconnection Charge (Rule 5)

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

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

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

III. Field Visit Charge- (Rule 5) $10.00

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

IV. Late Payment Charge – (Rule 5) $200.00

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

V. Returned Payment Charge - (Rule 6) $10.00

A returned check fee of ten dollars ($10.00) may apply for any payment returned unpaid.

VI. Residential Excess Flow Valves – (Rule 9)

a. Installation of an Excess Flow Valve: $ 38.00

The customer will be responsible for any maintenance or replacement costs that may be incurred due to the excess flow value. Such cost shall be based upon time and materials.

b. Modifying an Existing Service Line:

- Time of Construction Crew up to $220.00 per hour
- Cost of Materials required to open and close service connection trench, including asphalt replacement, if any.
- Installation of the Excess Flow Valve $38.00

SCHEDULE 201
SPECIAL CONTRACTS

PURPOSE

The purpose of this schedule is to describe generally the terms and conditions of service provided by the Company pursuant to special contracts approved by the Public Utility Commission of Oregon under OAR 860-022-0035. In each case, the rights and obligations of the parties are as specified in detail in the respective special contracts. In the event of any ambiguity or conflict between the summaries in this schedule and the substantive provisions of the special contracts, the terms of the special contracts shall be controlling. If a referenced rate schedules is no longer in effect, its most appropriate successor on file with the Commission should be used.

DESCRIPTIONS OF SPECIAL CONTRACTS

1. **LAMB-WESTON, INC. - HERMISTON, OREGON** - Market Based Distribution System Interruptible Transportation Service
   a. Term
      The contract was entered into on March 20, 1990 subject to Oregon Public Utility Commission (OPUC) approval. The initial term extends to September 30, 1991 and will continue in effect from year to year thereafter unless canceled by either party upon written notice of 120 days.

   b. Rates
      Buyer pays each month the Dispatching Service Charge and monthly rates applicable under Rate Schedule No. 164 as well as the transportation capacity charges under Optional Firm Pipeline Capacity Supplemental Schedule No. 185.

   c. Special Conditions
      All terms and conditions of service are consistent with Rate Schedule No. 164.

   d. Eligibility
      The "Availability" paragraph of Rate Schedule No. 164 outlines the conditions under which a customer can qualify for service. A condition precedent to availability is that contracts for service under Schedule No. 164 must be reviewed and approved by the Oregon Public Utility Commission pursuant to Oregon Statutes (ORS 757.230), Rules (OAR 860-022-0035), and Commission policies for market based rates (Order No. 87-402).

2. **LAMB-WESTON, INC. - BOARDMAN, OREGON** -- Distribution Transportation Service Special Contract
   a. Term
      The contract, dated October 27, 1995, has a minimum primary contract term of 20 years and will continue in effect thereafter from year to year until cancelled by either party with provision of at least one hundred twenty (120) days advance written notice.

(continued)

SCHEDULE 201
SPECIAL CONTRACTS

LAMB-WESTON, INC. - BOARDMAN, OREGON (continued)

b. Rates
The initial contract rate is based upon the specific service alternative (bypass of Company facilities) available to the customer. Buyer pays each month a Dispatch Service Charge under Distribution Rate Schedule 164 (presently of $500) as well as a monthly Facilities Charge of $1,750. A Commodity Charge of $0.007 will be charged for each therm of gas delivered within the Daily Contract Quantity (DCQ). Volume in excess of the DCQ will be charged at the commodity rate plus any costs or penalties incurred by Cascade in delivering those volumes.

Beginning October 1, 1996 and each October 1 thereafter for the duration of the contract, the Commodity Rate shall be escalated by the percentage change in the Consumer Price Index for the "All Urban Customers - U.S. City Average - All Items," for the twelve months ending on the immediately prior July 1. In addition, Lamb-Weston shall reimburse Cascade for State Utility Tax and other governmental levies imposed upon Cascade in rendering transportation service for Lamb Weston, Inc.

3. HEINZ FROZEN FOODS (formerly known as Ore-Ida Foods, Inc.) - ONTARIO, OREGON -- Distribution Transportation Service Special Contract

a. Term
The contract, dated December 15, 1995, has a minimum primary contract term of 15 years and will continue in effect thereafter from year to year until canceled by either party with provision of at least one hundred twenty (120) days advance written notice.

b. Rates
The initial contract rate is based upon the specific service alternative (bypass of Company facilities) available to the customer. Buyer pays each month a Dispatch Service Charge under Distribution Rate Schedule 164 (presently of $500) as well as a monthly Facilities Charge of $3,650. A Commodity Charge of $0.005 will be charged for each therm of gas delivered within the Daily Contract Quantity (DCQ). Volume in excess of the DCQ will be charged at the commodity rate plus any costs or penalties incurred by Cascade in delivering those volumes.

Beginning October 1, 1996 and each October 1 thereafter for the duration of the contract, the Commodity Rate shall be escalated by the percentage change in the Consumer Price Index for the "All Urban Customers - U.S. City Average - All Items," for the twelve months ending on the immediately prior July 1. In addition, Lamb-Weston shall reimburse Cascade for State Utility Tax and other governmental levies imposed upon Cascade in rendering transportation service for Heinz Frozen Foods.

c. Special Conditions
All operating obligations are detailed within the contract. Customer agrees that all gas used at the plant will be delivered by Cascade during the term of this agreement.

(continued)

SCHEDULE 201
SPECIAL CONTRACTS

HEINZ FROZEN FOODS - ONTARIO, OREGON (continued)

Contract provisions exist to address the potential for Adverse Regulatory Action by federal, state or municipal government or other regulatory authority, inclusive of the Oregon Public Utilities Commission. In the event such action occurs, the disadvantaged Party may terminate the agreement, given sufficient notice between the parties.

d. Eligibility
The contract is specifically designed to address the customer's potential distribution service alternative (bypass of Company facilities). A condition precedent to availability is that Special Contracts for service must be reviewed and approved by the Oregon Public Utilities Commission pursuant to Oregon Statutes (ORS 757.230), Rules (OAR 860-022-0035), and Commission policies for market based rates (Order No. 87-402).

c. Special Conditions
All operating obligations are detailed within the contract. Customer agrees that all gas used at the plant will be delivered by Cascade during the term of this agreement.

Contract provisions exist to address the potential for Adverse Regulatory Action by federal, state or municipal government or other regulatory authority, inclusive of the Oregon Public Utilities Commission. In the event such action occurs, the disadvantaged Party may terminate the agreement, given sufficient notice between the parties.

d. Eligibility:
The contract is specifically designed to address the customer's potential distribution service alternative (bypass of Company facilities). A condition precedent to availability is that Special Contracts for service must be reviewed and approved by the Oregon Public Utilities Commission pursuant to Oregon Statutes (ORS 757.230), Rules (OAR 860-022-0035), and Commission policies for market based rates (Order No. 87-402).

4. HERMISTON GENERATING COMPANY, L.P. - Firm Distribution Transportation Services Special Contract.

a. Term
The contract, dated March 28, 1994 with Amendment No. 1 dated June 3, 1994 and applicable letter agreements dated March 25, 1994, has a minimum primary contact term of 20 years and will continue in effect thereafter from year to year until canceled by either party with provision of at least one (1) year's advance written notice.

(continued)

SCHEDULE 201
SPECIAL CONTRACTS

<u>HERMISTON GENERATING COMPANY, L.P.</u> (continued)

b. <u>Rates</u>
The initial contract rate is based upon the specific service alternative (bypass of Company facilities) available to the customer. Buyer pays each month a Dispatch Service Charge of $500 as well as a monthly Demand Charge of $90,500. A monthly commodity Charge of $.001 will be charged for each MMbtu of gas delivered within the Daily Contract Quantity (DQC). Volume in excess of the DCQ will be charged at the commodity rate plus any costs or penalties incurred by Cascade in delivering those volumes.

Beginning October 1, 1997 and each October 1 thereafter for the duration of the contract, the Commodity Rate shall be escalated by the percentage change in the Consumer Price Index for the "All Urban Customers - U.S. City Average - All Items," for the twelve months ending on the immediately prior July 1. In addition, Hermiston Generating shall reimburse Cascade for State Utility Tax and other governmental levies imposed upon Cascade in rendering transportation service for Hermiston Generating Company.

c. <u>Special Conditions</u>
All operating obligations are detailed within the contract. Customer agrees that all gas used at the generating plant will be delivered by Cascade during the term of this agreement.

Contract provisions exist to address the potential for Adverse Regulatory Action by federal, state or municipal government or other regulatory authority, inclusive of the Oregon Public Utilities Commission. In the event such action occurs, the disadvantaged Party may cause transfer of distribution facilities ownership to Hermiston Generating given sufficient notice between the parties.

d. <u>Eligibility</u>
The contract is specifically designed to address the customer's potential distribution service alternative (bypass of Company facilities). A condition precedent to availability is that Special Contracts for service must be reviewed and approved by the Oregon Public Utilities Commission pursuant to Oregon Statutes (ORS 757.230), Rules (OAR 860-022-0035), and Commission policies for market based rates (Order No. 87-402).

(continued)

SCHEDULE 201
SPECIAL CONTRACTS

5. OREGON POTATO COMPANY - BOARDMAN, OREGON -- Distribution Transportation Service Special Contract

a. Term

The contract, dated December 29, 1995, has a minimum primary contract term of 20 years and will continue in effect thereafter from year to year until canceled by either party with provision of at least one hundred twenty (120) days advance written notice.

b. Rates

The initial contract rate is based upon the specific service alternative (bypass of Company facilities) available to the customer. Buyer pays each month a Dispatch Service Charge under Distribution Rate Schedule 163 (presently of $500) as well as a monthly Facilities Charge of $1,500. A Commodity Charge of $0.007 will be charged for each therm of gas delivered within the Daily Contract Quantity (DCQ). Volume in excess of the DCQ will be charged at the commodity rate plus any costs or penalties incurred by Cascade in delivering those volumes. Oregon Potato shall be obligated to a $35,000 minimum annual bill.

Beginning October 1, 1996 and each October 1 thereafter for the duration of the contract, the Commodity Rate shall be escalated by the percentage change in the Consumer Price Index for the "All Urban Customers - U.S. City Average - All Items," for the twelve months ending on the immediately prior July 1. In addition, Oregon Potato shall reimburse Cascade for State Utility Tax and other governmental levies imposed upon Cascade in rendering transportation service for Oregon Potato Company.

c. Special Conditions

All operating obligations are detailed within the contract. Customer agrees that all gas used at the generating plant will be delivered by Cascade during the term of this agreement.

Contract provisions exist to address the potential for Adverse Regulatory Action by federal, state or municipal government or other regulatory authority, inclusive of the Oregon Public Utilities Commission. In the event such action occurs, the disadvantaged Party may terminate the agreement, given sufficient notice between the parties.

d. Eligibility

The contract is specifically designed to address the customer's potential distribution service alternative (bypass of Company facilities). A condition precedent to availability is that Special Contracts for service must be reviewed and approved by the Oregon Public Utilities Commission pursuant to Oregon Statutes (ORS 757.230), Rules (OAR 860-022-0035), and Commission policies for market based rates (Order No. 87-402).

(continued)

SCHEDULE 201
SPECIAL CONTRACTS

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 287
OPTIONAL GAS MANAGEMENT SERVICES

AVAILABILITY

These services are available to end users transporting on Williams Gas Pipeline West (WGPW), West Coast Energy, Inc (WEI), and/or PG&E Gas Transmission Northwest (PG&E GT-NW) who currently purchase their own gas supply and transportation agreements.

GAS MANAGEMENT SERVICES DESCRIPTION

The Company will, acting as an agent, manage the transportation & delivery of natural gas on the interstate pipelines. Services offered under this schedule include the following:

- Daily Nominations on WGPW, WEI, Cascade Natural Gas Corporation, and/or PG&E GT-NW.
- Review of all nomination confirmations
- Pipeline Balancing services
- Monthly Management reports detailing delivered volumes, account balance positions, load factors achieved and weighted average cost of gas by month and year-to-date.
- Release unused firm transportation capacity on behalf of customer. Capacity equivalent to the Company's unused firm capacity will be marketed on a nondiscriminatory basis.

CONTRACT

Customers receiving service under this schedule shall execute a Gas Management Services agreement for those services for a period of not less than one year.

RATE

A. Gas Management Fee

A monthly management fee, for the performance of the daily gas management services, will be charged on a per MMBTU basis, as specified in the contract but not less than $.005 per MMBTU, for all natural gas consumed by the customer.

B. Mitigation Fee

A mitigation fee, equal to a percentage of the mitigated transportation expense, as specified in the contract, will be charged for capacity released on behalf of customers.

SCHEDULE 287
OPTIONAL GAS MANAGEMENT SERVICES

TERMS OF PAYMENT
Payment shall be due and payable within fifteen days from the date the bill is rendered.

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 700
CUSTOMER-OWNED PIPING

PURPOSE

This schedule offers services, at the option of the Company, to anyone that owns piping systems located within the Company's Oregon service territory. These services may be made available to customers outside of the Company's service territory with the Commission's prior approval. Under no circumstances will this schedule supersede the Company's response to any emergency situation.

DESCRIPTION

Under this schedule the Company will provide a menu of services for customer-owned piping systems. The services available under this schedule include the following:

- Design piping system
- Construct piping system.
- Operation and maintenance of customer-owned piping system
- Design cathodic protection system
- Install cathodic protection system
- Operation and maintenance of cathodic protection system
- Perform leak surveys
- Repair leaks
- Locating Services
- Odorization Testing
- Preparation of required reports to agencies, as required. Such reports may include Operation and Maintenance Plans, Written Emergency Plans, other compliance reports.

RATE

The charges for these services will be specified in the contract and will be on a time and material basis. The following represent standard service rates which apply during regular business hours.

Labor & Equipment:

Semi-Skilled Labor	up to $60 per hour
Skilled Labor	up to $75 per hour
Professional/Technical	up to $125 per hour
Supervisory/Specialist	up to $150 per hour
Service Truck w/Gas Technician	up to $75 per hour
Dump Truck w/ Driver	up to $85 per hour
Backhoe w/ Operator	up to $110 per hour
Welding Rig w/ Welder & Helper	up to $125 per hour
Construction Crew & Equipment	up to $265 per hour

SCHEDULE 700
CUSTOMER-OWNED PIPING

RATE (continued)

Services performed on Evenings/weekends will be charged at 1.5 times the standard hourly rate. Services performed on holidays will be charged at 2 times the standard hourly rate. Mileage will be charged at the IRS Standard Mileage Rate in effect at the time service are performed. A one hour minimum will apply.

Materials

Cost of materials plus 45% for handling.

CONTRACT

Customers receiving service under this rate schedule shall execute a contract for those services. The contract between the Company and customers will provide details about the duties of the Company and the customer with regard to defense and indemnity. The contract will specify the scope of services to be performed along with estimated time and material charges for the project. At the Company's option, customers may be offered a Fixed Price contract. Customers will be billed for actual time and materials unless opting for the Fixed Price Contract. For customers electing the fixed price contract, the price will be based on the estimated time and material required to complete the project as defined in the scope of services section of the contract.

TERMS OF PAYMENT

Payment shall be due and payable within fifteen days from the date the bill is rendered.

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.

CNGC/403
Archer

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

Pamela J. Archer
Exhibit No. 403

Housekeeping Revisions to the Tariff

HOUSEKEEPING REVISIONS TO THE TARIFF				
PUC Or. No. 9 (Current Tariff)		**PUC OR. No. 10 (New Tariff)**		
Current Tariff Sheet	**Current Title**	**New Tariff Sheet**	**New Title**	**Summary of Revisions**
Sheet No. 1	Cover Sheet	Sheet No. i	Cover Sheet	Reformatted, no changes in text
Sheet Nos. 2-2A	Index	Sheet Nos. ii through iii	Index	Reformatted. Headings changed for clarification.
Sheet No. 10	General	Sheet No. 1.1	Rule 1, General	Reformatted. No substantive changes to text.
Sheet Nos. 25 through 25-A	Rule 15, Definitions	Sheet Nos. 2.1 through 2.3	Rule 2, Definitions	Definitions include terms previously found in the Current Tariff, Rule 15. Definitions are placed at the beginning of the New Tariff to ensure that terms are defined before they are used in context. Defined terms are added, removed and revised as need for improved clarity.
Sheet No. 11 and Sheet No. 12	Rule 1, Applications and Contracts for Service Rule 2, Customer Deposits	Sheet Nos. 3.1 through 3.2	Rule 3, Establishing Service	New Tariff, Rule 3 defines the requirements for establishing service which include establishing a positive identification and proving credit worthiness. This information was previously found in both Rule 1 and Rule 2 of the Current Tariff.
Sheet Nos. 12 through 12-C	Rule 2, Customer Deposits	Sheet Nos. 4.1 through 4.4	Rule 4, Customer Deposits	New Tariff, Rule 4 includes the information on customer deposits formerly in Current Tariff, Rule 2. The information in Current Tariff, Rule 2 regarding requirements for establishing service has been included in Rule 3.
Sheet Nos. 13 through 13-F	Rule 3, Discontinuance of Service	Sheet Nos. 5.1 though 5.7	Rule 5, Discontinuation of Service	Rule 5 is revised to remove amounts for defined fees. It is administratively more efficient to have the amount charged for fees stated only in Schedule 200 so that a reference is not missed when the charge is updated. The grounds for disconnecting gas service are revised to ensure they are consistent with OAR 860-021-0305. Finally, the Disconnect Visit Charge is renamed the Field Visit Charge to clarify the fee is not incurred when service is disconnected; rather it is applied when the Company is unable to either disconnect or reconnect service as planned.
Sheet Nos. 14 through	Rule 4, Billing	Sheet Nos. 6.1 through 6.5	Rule 6, Billing	New Tariff, Rule 6, Billings updates the information found in Current Tariff, Rule 4 so that the practices for correcting under-

HOUSEKEEPING REVISIONS TO THE TARIFF				
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14-B				and overbillings are consistent with the changes to OAR 860-021-0135 adopted in Commission Order No. 14-230. Also, the Returned Check Fee is renamed the Returned Payment Fee so that the name is consistent with the practice of applying this charge when any payment channel where funds are insufficient.
Sheet No. 15	Rule 5, Meters	Sheet No. 7.1	Rule 7, Meters	Wording is removed that disallowed sharing or reselling of gas. This wording has become inconsistent with landlord/tenant utility billing arrangements allowed per ORS Chapter 90. Wording is added to clarify the Company is not required to provide submeters or any services related to submeters since submeters are installed on the customer-owned side of the service line.
Sheet Nos. 16 through 16-A	Rule 6, Meter Testing	Sheet Nos. 8.1 through 8.2	Rule 8, Meter Testing	The Company's address is updated.
Sheet Nos. 17 through 17-A	Rule 7¸ Service Line Installations	Sheet Nos. 9.1 through 9.2	Rule 9, Service Line Installations	Language on excess flow valves that is repeated in Schedule 200 is removed. The adder for taxes has been updated.
Sheet No. 18	Rule 8, Main Extensions	Sheet Nos. 10.1 through 10.2	Rule 10, Main Extensions	As in New Tariff, Rule 9, the adder for taxes is updated from 26.56% to 20.38%.
Sheet No. 19	Rule 9, House-Piping	Sheet No. 11.1	Rule 11, House-Piping	No substantive changes.
Sheet No. 20	Rule 10, Responsibility for Maintenance of Service Connections	Sheet No. 12.1	Rule 12, Responsibility for Maintenance of Service Connections	No substantive changes.
Sheet No. 21	Rule 11, Temporary	Sheet No. 13.1	Rule 13, Temporary	No substantive changes.

HOUSEKEEPING REVISIONS TO THE TARIFF				
PUC Or. No. 9 (Current Tariff)		PUC OR. No. 10 (New Tariff)		
Current Tariff Sheet	Current Title	New Tariff Sheet	New Title	Summary of Revisions
	Service		Service	
Sheet No. 22	Rule 12, Company's Responsibility	Sheet No. 14.1	Rule 14, Company Responsibility	No substantive changes.
Sheet No. 23	Rule 13, Customer's Responsibility	Sheet No. 15.1	Rule 15, Customer Responsibility	No substantive changes.
Sheet No. 24	Rule 14, Force Majeure	Sheet No. 16.1	Rule 16, Force Majeure	No substantive changes.
Sheet No. 26	Rule 16, Promotional Activities	Removed in its entirety.		
Sheet Nos. 27 through 27-C	Rule 17, Firm Service Priority	Sheet Nos. 17.1 through 17.3	Rule 17, Order of Priority for Gas Service	The title of this rule is revised in order to broaden the scope to all customers as opposed to only firm service customers. References to Optional Firm Pipeline Capacity service is removed as this service option was frozen some time ago and no customers are currently receiving this service. Also, the language on Transportation Entitlement Periods is removed as the language as this is only applicable to transportation customers served on Schedule 163. The parameters for curtailment applicable to all customers are clarified.
Sheet No. 28	Rule 18, Limitation of Firm Natural Gas Service	Sheet No. 18.1	Rule 18, Limitation of Firm Natural Gas Service	This rule is simplified and updated by removing outdated references to the Federal Power Commission and to gas scarcity.
Sheet Nos. 30 through 30-A	Rule 19, Conservation Alliance Plan Mechanism	Sheet Nos. 19.1 through 19-2	Rule 19, Conservation Alliance Plan Mechanism	No changes.
Sheet No. 31 through 31-A	Schedule No. 31, Public Purposes	Sheet No. 31.1 through 31.2	Schedule 31, Public Purpose Charge	No changes.

HOUSEKEEPING REVISIONS TO THE TARIFF				
PUC Or. No. 9 (Current Tariff)		PUC OR. No. 10 (New Tariff)		
Current Tariff Sheet	**Current Title**	**New Tariff Sheet**	**New Title**	**Summary of Revisions**
	Funding			
Sheet Nos. 32 through 32-A	Schedule No. 32, Oregon Low Income Bill Assistance Program	Sheet Nos. 32.1 through 32.2	Schedule 32, Oregon Low Income Assistance Program	No changes.
Sheet Nos. 33 through 33-D	Schedule No. 33, Oregon Low Income Energy (OLIEC) Program	Sheet Nos. 33.1 through 33.7	Schedule 33, Oregon Low-Income Energy Conservation Program	No changes.
Sheet No. 34	Schedule No. 34, Energy Efficiency Services and Programs	Sheet No. 34.1	Schedule 34, Energy Efficiency Services and Programs	No changes.
Sheet No. 100	Schedule No. 100, Adjustment for Municipal Exactions	Sheet No. 100.1	Schedule 100, Adjustment for Municipal Exactions	No changes.
Rate Schedules		The text in the New Tariff rate schedules and adjustment schedules is uniformly reformatted. Where applicable, the following changes were made to the rate schedules: • The reference to Schedule 194-A, "UM 1283 Merger Rate Credits" is removed from the New Tariff with this filing as this credit expired in 2012. • Language about meter configurations in the Availability sections is removed. Meter configuration is discussed in Rule 7, "Meters" of the Current Tariff and is not a term for service availability as the placement of the language currently implies. • The prohibition against submetering and reselling natural gas is removed. Submetering is a customer decision as it is on the customer-side of the meter, and a landlord can resell gas under the provisions established in ORS Chapter 90. • A description of "General Terms" is added to each rate and adjustment schedule which states that service under the rate schedule broadly includes compliance to all approved and appropriate laws, rules, and regulations. In general, where terms universally applicable to all rates schedule are inadvertently not in a current		

HOUSEKEEPING REVISIONS TO THE TARIFF				
PUC Or. No. 9 (Current Tariff)		**PUC OR. No. 10 (New Tariff)**		
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		schedule, they are added to the proposed schedule. "No changes" below means nothing substantive beyond the changes described here were made. Please Note: this matrix does **not** address the changes to basic service charges or rates.		
Sheet No. 101	Rate Schedule No. 101, General Residential Service	Sheet No. 101. 1	Schedule 101, General Residential Service	No changes.
Sheet No. 104	Rate Schedule No. 104, General Commercial Service	Sheet No. 104.1	Schedule 104, General Commercial Service	No changes.
Sheet No. 105	Rate Schedule No. 105, General Industrial Service	Sheet No. 105.1	Rate Schedule 105, General Industrial Service	No changes.
Sheet No. 111	Rate Schedule No. 111, Large Volume General Service	Sheet No. 111.1 through 111. 2	Rate Schedule 111, Large Volume Service	No changes.
Sheet No. 112	Rate Schedule No. 112, Compressed Natural Gas Service	Sheet No. 112.1 through 112. 2	Rate Schedule 112, Compressed Natural Gas Service	No changes.
Sheet No. 126 through 126-A	Rate Schedule No. 126, Emergency Institutional Services	Sheet No. 126.1 through 126. 2	Rate Schedule 126, Emergency Institutional Services	No changes.
Sheet No. 145	Rate Schedule No. 145, Residential Heating Equipment Rental Rate	Removed in its entirety.		
Sheet Nos. 163 through 163-A	Rate Schedule No. 163, General Distribution System Interruptible Transportation Service	Sheet Nos. 163.1 through 163.9	Rate Schedule 163, General Distribution System Interruptible Transportation Service	New Tariff, Schedule 163 is the combination of current Schedule Nos. 163 and 183, as service on one implies service on both. Current Tariff, Schedule No. 163 provides the cost for transporting customer-owned gas and Current Tariff, Schedule No. 183 establishes the terms for customer-owned gas such as nominating gas, balancing gas, and complying with entitlement

HOUSEKEEPING REVISIONS TO THE TARIFF				
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Current Tariff Sheet	**Current Title**	**New Tariff Sheet**	**New Title**	**Summary of Revisions**
				periods. All of this is now in New Tariff, Schedule 163. The information is reformatted and text is added to provide clarification.
Sheet Nos. 170 through 170-A	Rate Schedule No. 170, Interruptible Service	Sheet Nos. 170.1 through 170.2	Rate Schedule 170, Interruptible Service	Clarification is added on curtailment charges.
Sheet Nos. 175 through 175-A	Schedule No. 175, Energy Efficiency Investment Recovery Adjustment Provision	Removed in its entirety. Energy efficiency program costs are recovered through Schedule 31, Public Purpose Funding.		
Sheet Nos. 177 through 177-B	Schedule No. 177, Purchased Gas Cost Adjustment Provision	Sheet Nos. 177.1 through 177.4	Schedule 177, Purchased Gas Cost Adjustment Provision	No changes.
Sheet Nos. 183 through 183-D	Schedule No. 183, Optional Customer Owned Gas Supply	Removed in its entirety. The information in this schedule was placed in New Tariff, Schedule 163.		
Sheet Nos. 185 through 185-B	Schedule No. 185, Optional Firm Pipeline Capacity	Removed in its entirety. This schedule was previously frozen and no customer is served on it.		
Sheet No. 190 through 190-A	Schedule No. 190, Buy-Sell Supply Service	Removed in its entirety. This schedule was previously frozen and no customer is served on it.		
Sheet No. 191	Schedule No. 191, Temporary Gas Cost Rate Adjustment	Sheet No. 191.1	Schedule 191, Temporary Gas Cost Rate Adjustment	No changes.
Sheet No. 192	Schedule No. 192, Intervenor Funding Adjustment	Sheet No. 192.1	Schedule 192, Intervenor Funding Adjustment	No changes.
Sheet No. 193	Schedule No. 193, UG 167 Conservation Alliance Plan	Sheet Nos. 193.1	Schedule 193, Conservation Alliance Plan	No changes.

HOUSEKEEPING REVISIONS TO THE TARIFF				
PUC Or. No. 9 (Current Tariff)		PUC OR. No. 10 (New Tariff)		
Current Tariff Sheet	**Current Title**	**New Tariff Sheet**	**New Title**	**Summary of Revisions**
	Temporary Adjustments		Adjustment	
Sheet No. 196	Schedule 196, UM 903 Oregon Earnings Sharing	Sheet No. 196.1	Schedule 196, UM 903 Oregon Earnings Sharing	No changes.
Sheet Nos. 200 through 200-A	Schedule No. 200, Various Miscellaneous Charges	Sheet No. 200.1	Schedule 200, Various Miscellaneous Charges	Reformatted.
Sheet Nos. 201 through 201-E	Schedule No. 201, Special Contracts	Sheet Nos. 201.1 through 201.6	Schedule 201, Special Contracts	General terms added as well as language stating that where a referenced rate schedules is no longer in effect, its most appropriate successor on file with the Commission should be used.
Sheet No. 287	Schedule No. 287, Optional Gas Management Services	Sheets Nos. 287.1 through 287.2	Schedule 287, Optional Gas Management Services	No changes.
Sheet No. 700 through 700-A	Schedule No. 700, Optional Customer-Owned Piping Construction, Operation, & Maintenance	Sheet Nos. 700-1 through 700-2	Schedule, 700, Optional Customer-Owned Piping Construction, Operation, & Maintenance	No changes.

BEFORE THE

PUBLIC UTILITY COMMISSION OF OREGON

DOCKET NO. UG 305

Pamela J. Archer
Exhibit No. 404

Calculation of the Income Tax Factor on Customer Contributions

Cascade Natural Gas Corporation

CALCULATION OF THE INCOME TAX FACTOR ON CUSTOMER CONTRIBUTIONS

State of Oregon

Year	Tax Deprec. Rate		State & Federal Effective Tax Rate	Amount
	(a)		(b)	(c)
1	3.7500%		36.175%	0.013566
2	7.2188%		36.175%	0.026114
3	6.6773%		36.175%	0.024155
4	6.1765%		36.175%	0.022343
5	5.7133%		36.175%	0.020668
6	5.2848%		36.175%	0.019118
7	4.8884%		36.175%	0.017684
8	4.5218%		36.175%	0.016358
9	4.4616%		36.175%	0.016140
10	4.4615%		36.175%	0.016139
11	4.4616%		36.175%	0.016140
12	4.4615%		36.175%	0.016139
13	4.4615%		36.175%	0.016139
14	4.4615%		36.175%	0.016139
15	4.4615%		36.175%	0.016139
16	4.4616%		36.175%	0.016140
17	4.4615%		36.175%	0.016139
18	4.4615%		36.175%	0.016139
19	4.4615%		36.175%	0.016139
20	4.4615%		36.175%	0.016139
21	2.2308%		36.175%	0.008070
22	Authorized Overall Return		7.306%	
23	Present Value			0.192457
24	1-FIT + Present Value			0.830707
25	Multiplier			**1.2038**