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July 30, 2020

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
ATTENTION: FILING CENTER
PO BOX: 1088
SALEM OR 97308-1088

RE: Docket No. UG 390 – In the Matter of CASCADE NATURAL GAS CORPORATION, Request for a General Rate Revision

Attached for filing are the following exhibits:

- Cover Letter
- Exhibit 100 - 112 Fjeldheim
- Exhibit 200 - 203 Cohen
- Exhibit 300 - 302 Dlouhy
- Exhibit 400 - 402 Zarate
- Exhibit 500 - 502 Fox
- Exhibit 600 - 602 Gibbens
- Exhibit 700 - 702 Moore
- Exhibit 800 - 802 Peng
- Exhibit 900 - 902 Rossow
- Exhibit 1000 - 1004 Soldavini
- Exhibit 1100 - 1101 St. Brown

/s/ Kay Barnes

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CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Brian Fjeldheim. I am a Senior Financial Analyst employed in the Energy Rates and Accounting Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I am the revenue requirement summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding I introduce Staff-sponsored adjustments and issues regarding the Cascade Natural Gas Company's (CNG, cascade, or Company) request for a general rate revision, docketed as Docket No. UG 390. As such, I verify Cascade's proposed revenue requirement utilizing Staff's revenue requirement model. This model is also used to calculate Staff's modified revenue requirement after incorporating the Staff's proposed adjustments to the Company's revenue requirement.

I am also the Staff analyst on several issues and present Staff's analysis and recommendations regarding the rate treatment for these issues.

Q. Will other Staff witnesses submit testimony regarding the issues they reviewed?

A. Yes. Each Staff assigned to Docket No. UG 390 is submitting separate testimony. In Part 1 of my testimony, I introduce the Staff witnesses and their respective assignments, and estimate the revenue requirement impact of Staff recommended adjustments to the Company's initial filing. These are the issues identified to date. Staff's recommendations and issues may change after reviewing testimony and analysis by other parties.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

Staff/101	Witness Qualification Statement.
Staff/102	Gas Storage in Rate Base – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/103	Gas Storage Operating Expense – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/104	Other Gas Supply and Purchased Gas Expense – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/105	Distribution O&M Expense (non-labor) – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/106	A&G Expense (non-labor) – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/107	Other Taxes (excluding income taxes) – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/108	Materials and Supplies Inventory and Expense – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/109	Prepaid Expense – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/110	Rate Case Expense – Associated Cascade workpaper and responses to Staff Data Requests.
Staff/111	Staff Workpaper – Correction to Cascade's Conversion Rate calculation.

Q. How is your testimony organized?

A. My testimony is organized as follows:

PART 1. REVENUE REQUIREMENT

Q. What is at issue in Cascade's rate case?

A. The Company requests a revision to customer base rates that will increase the Company's annual Oregon jurisdictional revenues by $4,507,842 for an increase of 6.67 percent over current customer rates resulting in a total revenue requirement of $72,086,038. The Company also requests a revision to its amortization rate to recover environmental remediation costs that will increase the Company's annual revenues by $363,765. The combined impact is an incremental increase request of $4,871,607 or 7.21 percent, for an overall revenue requirement of $72,449,803.

The Company bases this request on a twelve-month test year ending December 31, 2020 (Test Year). Cascade provides information for a historical base year of the twelve-months ending December 31, 2019 (Base Year) and adjusts that information to reflect the forecasted Test Year.

Q. What is Staff's recommendation regarding the Company's request?

A. The following table summarizes the Company request and Staff's proposed adjustment for each issue:

Table A

			STAFF ISSUE SUMMARY				
CNG requested Incremental Revenue Requirement							**$ 4,507,842**
Opening Testimony Exhibit No.	**Staff Witness**	**Issue No.**	**Issue Description**	**Revenue**	**Expense**	**Rate Base**	**Revenue Requirement Effect**
Stipulation	Muldoon		Stipulated Cost of Capital (excludes Interest Sync.)				($7,496)
100	Fjeldheim	1	Gas Storage in Rate Base				
100	Fjeldheim	2	Gas Storage Operating Expense				
100	Fjeldheim	3	Other Gas Supply Expense		(22,800)		(23,518)
100	Fjeldheim	4	Distribution O&M Expense		(187,000)		(192,889)
100	Fjeldheim	5	A&G Expense		146,000		150,598
100	Fjeldheim	6	Other Taxes				
100	Fjeldheim	7	Materials & Supplies Inventory & Expense				
100	Fjeldheim	8	Prepaid Expense				
100	Fjeldheim	9	Rate Case Expense		(93,000)		(95,929)
100	Fjeldheim	10	Company Conversion Rate*				
100	Fjeldheim	11	Interest Sync - Stip. Cost of LTD				2,024
200	Cohen	1	Wages & Salaries		(2,032,513)	(586,670)	(2,149,833)
200	Cohen	2	Uncollectible Expense				
200	Cohen	3	Advertising		(7,912)		(8,161)
200	Cohen	4	Customer Accounts		(20,979)		(21,640)
300	Dlouhy	1	Pension Expense		(23,621)		(24,365)
400	Zarate	1	Customer Support Programs				
400	Zarate	2	Energy trust of Oregon				
400	Zarate	3	Gains or Losses in Sales Property				
500	Fox	1	Utility Plant			(1,202,000)	(109,227)
500	Fox	2a	State & Federal Income Tax	-	(383,000)		(541,210)
500	Fox	2b	Other Income	389,000			(389,000)
500	Fox	2c	Taxes Other Than Income - CAT		200,000		206,298
600	Gibbens	1	Load Forecast and Sales Revenue				
600	Gibbens	2	Decoupling				
700	Moore	1	General Plant Maintenance				
700	Moore	2	Employee Benefits				
700	Moore	3	Insurance				
800	Peng	1	Analysis of Depreciation from Ratemaking Perspective				

Opening Testimony Exhibit No.	Staff Witness	Issue No.	Issue Description	Revenue	Expense	Rate Base	Revenue Requirement Effect
800	Peng	2	Depreciation Effect on Revenue Requirement (UM 2073 Depr rates & Final UG 390 Utility Plant in Rate Base) Pending				
800	Peng	3	Regulatory Capitalization Policy				
800	Peng	4	FERC AFUDC Requirements				
900	Rossow	1	Membership & Dues				
900	Rossow	2	Meals & Entertainment & Misc		216,032		222,835
1000	Soldavini	1	Other Income	24,981			(24,981)
1000	Soldavini	2	Affiliate & Jurisdictional Cost Allocation				
1100	St. Brown	1	LRIC, rate spread, and rate design issues - Stipulation pending				
Total Staff-Proposed Adjustments (Base Rates):				$413,981	($2,208,794)	($1,788,670)	($3,006,494)
							$ 1,501,348

* Note - No Incremental Revenue Requirement Effect included for Conversion Rate change in Table A. Staff's proposed decrease to CNG's conversion rate and NTG factor will impact calculated revenue requirement required for authorized ROR on final rate base. Staff's proposed decrease to the conversion rate and NTG factor on the Company's filed case reduces Total Revenues by $11,677 & Expenses by $11,677, which nets to $0. See Staff Excel workpaper, UG 390 Exh 100 Staff's Model adjusting CNG Conv Factor WP.xlsx, Summary tab, col 10.

PART 2. STAFF ISSUES AND ANALYSIS

Q. What areas of Cascade's filing are you primarily responsible for reviewing?

A. In my testimony, I review interest rate synchronization, gas storage in rate base, gas storage operating expense, other gas supply and purchased gas expense, distribution operations and maintenance (O&M) expense, administrative and general (A&G) expense, other taxes (excluding income taxes), materials and supplies inventory and expense, prepaid expense, rate case expense, and Cascade's conversion rate calculation. In order to gain additional insight, I reviewed the Company's responses to Staff's Standard Data Requests (SDRs), issued additional DRs, and reviewed the Company's responses.

ISSUE 1. GAS STORAGE IN RATE BASE

Q. Please describe the gas storage costs at issue.

A. Storage gas consists of two components, “cushion gas” and “working gas inventory.” “Cushion gas” is permanently retained in storage to maintain operational pressure and prevent water deterioration in an underground storage reservoir.[1] “Working gas inventory” is the gas that flows in and out of a storage reservoir, or Liquid Natural Gas (LNG) tank, to serve customer loads.[2] Cascade does not own gas storage facilities and therefor owns no “cushion gas.”[3] Accordingly, the only costs for storage gas at issue in this rate case are those for working gas inventory.

Q. Please summarize the Commission’s historical treatment of gas storage in rate base.

A. All three regulated gas utilities serving in Oregon currently include gas storage costs in rate base.[4]

Q. Please summarize Cascade’s proposed rate treatment for “working gas” stored gas costs.

A. Cascade used a 13 month average of monthly averages (AMA) calculation for their Base Year working gas storage costs.[5] The 2019 AMA for the 2019 Base Year is $208 thousand for liquefied natural gas stored and $435

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[1] See *In the Matter of Northwest Natural*, Docket No. UM 1651, Order No. 13-349 at 1 and 5.
[2] *Id.*
[3] See Staff/102, Cascade’s response to Staff DR Nos. 220 and 221.
[4] See e.g., *In the Matter of Northwest Natural*, Docket UM 1651, Order No. 13-349 at 5 (Commission adopting stipulation including Northwest Natural Gas Company’s working gas inventory in rate base).
[5] See Staff/102, Cascade’s response to Staff DR No. 222.

thousand for prepaid gas storage, totaling $643 thousand in rate base.[6] Cascade proposes no Test Year adjustment. Staff reviewed Cascade's AMA calculations for natural gas stored underground and liquefied natural gas stored and found no errors.

Q. Did Staff issue data request(s) to Cascade concerning working gas inventory?

A. Yes. In addition to reviewing the Company's responses to Standard Data Request (SDR) Nos. 057 and 058, Staff issued Data Requests (DR) Nos. 221 and 222 requesting monthly storage inventory levels, by gas volume and dollar value, as well as the monthly storage guideline for each storage facility, for the past 10 years. Cascade provided the most recent 10 years of data (2010-2019).

The Company provided detailed documentation in support of $643 thousand for prepaid gas storage expense in their response to Staff DR No. 222. However, this dollar amount contradicts the dollar amount of $962 thousand the Company provided in response to Staff SDR No. 058 for gas storage in rate base. Staff is requesting clarification from the Company as to which dollar amount is correct.[7]

Q. Please summarize Staff's analysis of Cascade's responses to DR 222.

A. Using data provided in Cascade's response to DR No. 222 – Rate Base 2019 and the Company's original filing,[8] Staff calculated the dollar amount

[6] *Id*., Cascade Excel file "OPUC-222 – Rate Base 2019", tab "DEC19", rows 98 – 108.
[7] The Company's response to Staff DR No. 268 is pending.
[8] See Exhibits CNGC/301-302, Peters; and Company Excel work paper "MCP-WP1 (Rev Req)".

for the working gas inventory in rate base using the most recent calendar year (2019), the most recent 13 month average of monthly averages (AMA), a three-year calendar annual moving average, a three year AMA average, and a ten-year calendar average (2010 – 2019). Staff's practice is to consider the most recent three-year averages more heavily than a longer-term trend as the basis to calculate an adjustment for gas storage in rate base. Staff believes near term trends in gas pricing are likely to provide a more accurate projected gas price for future periods. In general, Oregon city gate gas prices steadily declined over the past 10 years. To illustrate this, the Oregon city gate price for natural gas was approximately $7.79 per dekatherm in 2009, approximately $4.82 per dekatherm in 2013, and approximately $3.56 per dekatherm in 2019.[9]

Q. What is Staff's proposed adjustment to Gas Storage in rate base?

A. In May of 2019, the Company began leasing 600,000 dekatherms (dth) of additional gas storage capacity from Mist. This additional storage capacity is being provided under a five-year lease from NW Natural with an expiration date of April 30, 2024.[10] The additional storage capacity was not available in prior years, therefore trend analysis of prior periods does not provide a meaningful projection for the Test Year. In this instance, Staff

[9] Pricing provided by the U.S. Energy Information Administration and accessed at https://www.eia.gov/dnav/ng/hist/n3050or3a.htm.
[10] Cascade and NW Natural provided information supporting this during the Q2, 2019 PGA update meeting with Staff and Parties to Docket No. UM 1286.

believes the Company's 13-month AMA dollar amount for 2019 represents the most reasonable Test Year amount.

Q. Does Staff propose an adjustment to Gas Storage in rate base?

A. No. Staff proposes no adjustment for storage gas in the Test Year rate base.

ISSUE 2. GAS STORAGE OPERATING EXPENSE

Q. What are "gas storage operating expenses"?

A. Expenses for gas storage and gas storage operations are recorded in Federal Energy Regulatory Commission (FERC) accounts 814-843.[11]

Q. Please summarize Cascade's proposal related to gas storage expense.

A. The Company does not own or operate a gas storage facility.[12] No expenses for FERC accounts 814-843 are included in this rate case.

Q. Please describe your proposed adjustment of underground storage expense.

A. Cascade does not propose to recover amounts for gas storage or gas storage operating expense in this proceeding. Staff proposes no adjustment.

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[11] The full description of 18 C.F.R. FERC Gas Accounts can be accessed here: https://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.6.46&idno=18.

[12] See Exhibit Staff/103, Company response to DR Nos. 220 and 221.

ISSUE 3. OTHER GAS SUPPLY AND PURCHASED GAS EXPENSE

Q. What is "other gas expense?"

A. For purposes of my analysis, "other gas expenses" are the non-labor expenses recorded in FERC account 813 (other gas supply expenses), and include the cost of materials and non-labor expenses incurred in connection with gas supply functions, including research and development, not provided for in any other FERC account for gas expense.[13]

Q. Please summarize Cascade's proposal related to other gas expense.

A. Cascade is seeking Test Year recovery of $113 thousand for other gas expenses recorded in FERC account 813 for both labor and non-labor expense. According to the Company's response to SDR Nos. 057, 058, and Staff DR No. 219, the total Base Year expense is $111 thousand, of which approximately $51 thousand of the Base Year expense was non-labor expense.[14],[15]

Q. Please summarize Cascade's proposal related to gas purchases.

A. In the Company's initial filing workpapers, Excel file "UG 390 – Peters MCP-WP1", tab "Exh 301 - ROO Summary Sheet", row 18 illustrates that natural gas purchases are removed from the rate case. This is in keeping with the annual purchase gas adjustment (PGA) mechanism whereby gas utilities

[13] See 18 C.F.R. § 205 (FERC account 813).
[14] See Staff/104, Fjeldheim.
[15] See Cascade workpaper Excel file "UG 390 – Peters MCP-WP1", tab "Inflation Factor", row 9.

receive an annual cost recovery adjustment for natural gas commodity purchases.[16]

Q. What is Staff's analysis and recommendation?

A. Staff did not identify any dollar amounts associated with gas commodity purchases included in this rate filing. Regarding other gas expenses included in the filing, the Company provided limited historical data to support the Test Year request. Staff issued DR No. 219 requesting 10 years of historical actuals for other gas supply expenses. The Company provided the requested ten years of labor and non-labor data. Staff only considered the non-labor portion of the requested expenditure for purposes of this analysis. Staff witness Heather Cohen investigates labor expenses in Exhibit Staff/200.

Staff reviewed the data supplied in response to DR No. 219 for potential outliers and more recent trends. In the 2018 - 2019 period, there was a 76.7 percent increase in annual non-labor other gas expenditures from $28,529 to $50,516. Cascade used the $50,516 as the Base Year amount and escalated by 1.8 percent to arrive at the Test Year expense.

In reviewing the Company's response to Staff SDR No. 057, Staff identified a one-time expenditure in 2019 for a damage payment expense related to Puget Sound Energy – Fredonia, for which Oregon ratepayers were allocated $21,000. Cascade did not provide information on this expense. Staff's review of expense for FERC Account 813 in the previous

[16] See Docket No. UG 73, Order No. 89-1046 and Docket No. UM 1286.

two years did not reveal similar expense. When the $21,000 expense is removed, the remaining non-labor other gas expense allocated to Oregon is approximately $29,000, which is consistent with the amounts attributable to Oregon customers in 2018 and 2017, $28,529 and $29,980, respectively.

Staff believes it is appropriate to remove the $21,000 payment to Puget Sound Electric from other gas expense as a non-recurring payment for purposes of determining Cascade's Test Year expense. Cascade has offered no evidence to show why this expense is a normal expense that Cascade can expect to incur on an annual basis.

In reviewing the Company's proposed escalation for other gas expense, Staff noted that Cascade included both labor and non-labor Base Year other gas expense of $111 thousand in their escalation calculation in conjunction with a consumer price index – all urban (CPI-U) escalation rate of 1.8 percent. Staff excluded labor from its review here. Staff recommends using a three-year average for non-labor expense, less the $21 thousand dis-allowance for a Puget Sound Energy damages payment in 2019, with an updated consumer CPI-U escalation factor of 0.7 percent.[17]

[17] June 2020 CPI-U = 0.7 percent. Obtained from the Oregon Office of Economic Analysis – June 2020 forecast available here https://www.oregon.gov/das/OEA/Documents/appendixa.pdf.

Q. Please describe Staff's proposed adjustment of purchased gas and other gas supply expense.

A. The Company's actual cost of natural gas purchases is reconciled via the annual PGA.[18] Staff proposes no change to purchased gas expense in this case.

Regarding Cascade's request to recover approximately $113 thousand in Test Year other gas supply expense, Staff is only considering the non-labor component in the following recommended adjustments:

1) Dis-allow $21 thousand Base Year expense for Puget Sound Energy.
2) Remove the labor component of $60 thousand from the Company's CPI-U escalation calculation. This results in a ($1,792) reduction to the Test Year escalation adjustment.
3) Use a three-year average for other gas supply expense, less the Puget Sound Energy adjustment from 1) then escalate using the June 2020 CPI-U. This results in a Test Year non-labor amount of $30 thousand.

[18] Order No. 14-238 in Docket No. UM 1286.

ISSUE 4. DISTRIBUTION O&M EXPENSE (NON-LABOR)

Q. Please describe the expenses included in this issue.

A. Distribution O&M expenses are recorded in FERC accounts 870-894 and are allocated between Oregon and Washington operations, with discrete state costs (situs) booked 100 percent to the state of operation. Costs that are non-discrete are allocated on a fixed percentage basis. In the Base Year, the Company's cost allocation factor for Oregon is 24.83 percent.[19]

Q. Please provide a summary of the Company's filed proposal for this issue.

A. FERC accounts 871-881 are primarily operational in nature and include activities such as distribution and load dispatching, compressor station and mains operations, measuring and regulating station expenses, customer installs and metering expenses, and utility rents. FERC accounts 882-894 primarily involve system maintenance activities and include maintenance supervision, mains and compressor station maintenance, measuring and regulating station equipment maintenance, and maintenance of meters and other operating equipment.

In the Company's Revenue Requirement model, Cascade used a non-labor Base Year expense for Distribution O&M. Cascade arrived at this amount using Oregon total 2019 Distribution O&M expenditures (FERC accounts 870-894) of $6,651,691 and then subtracted $3,367,458 for Base Year union wages, resulting in a non-labor Base Year amount of

[19] See Exhibit CNGC/305, Peters/1-2.

$3,284,232. Cascade then escalated the calculated non-labor expense using an escalation rate of 1.8 percent.[20] The Company's workpapers indicate that it is requesting non-labor Distribution escalation of $59,116 for FERC accounts 870-894.[21] The Company did not indicate any normalizing adjustments from the Base Year to the Test Year for Distribution O&M expenses.[22]

Q. Please discuss Staff's analysis of these expenditures.

A. Staff first reviewed the reasonableness of Distribution O&M expenses by comparing the utility's proposed Test Year expense to various historical benchmarks, including a three-year average.

Staff reviewed the Base Year non-labor Distribution O&M expenses of $2.127 million provided in the Company's response to Staff SDR Nos. 057 and 058. From this, Staff reviewed two data samples of the 200 largest O&M expenditures, by Oregon situs and by Oregon allocated expense. Staff did not identify any disallowed or one-time expenses in the Base Year data sampled. Staff noted that payments totaling $58,285 were made to an affiliate, Knife River, but made no adjustments.

Staff then reviewed three years of summary level non-labor expenses provided in the Company's response to Staff SDR No. 058 and calculated a three-year non-labor average of $1.971 million (2017-2019).

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[20] See Cascade workpapers, Excel file "UG 390 – Peters MCP-WP 1", tab "Inflation Factor", columns B-F.
[21] See Exhibit CNGC/304, Peters/1, column (k).
[22] *Id.*, row 12

Finally, Staff escalated the three-year average, to include the Base Year, using the June 2020 CPI-U rate of 0.7 percent.[23] This resulted in a Test Year escalation adjustment of $14 thousand, resulting in a total Test Year amount of $1.985 million.

Q. Did Staff note any differences between the Company's calculations and Staff's calculations?

A. Yes. First, the Company's calculation for Base Year non-labor O&M expense of $3.284 million is $1.157 million higher than the $2.127 million figure the Company provided in response to Staff SDR Nos. 057 and 058. The Company provided no additional details or documentation to support the $3.284 million figure. As such, it is Staff's position that the $2.127 million amount in the Company's response to SDR Nos. 057 and 058 is better supported than the dollar amount in the Company's revenue requirement inflation factor model. Using the $2.127 million figure above, Staff applied the Company's inflation factor of 1.8 percent to re-calculate the Company's proposed Test Year escalation, resulting in an escalation amount of $38,277, which is $20,839 less than the Company's proposed escalation.

Additionally, Staff used the June 2020 CPI-U factor of 0.7 percent to calculate Test Year escalation, which is 1.1 percentage points lower than the Company's 1.8 percent escalation used in their filing. In light of the

[23] Oregon Department of Administrative Services – Office of Economic Analysis, June 2020 Revenue Forecast, which can be found at https://www.oregon.gov/das/OEA/Pages/Index.aspx

significant decline in economic activity since the beginning of 2020, it is Staff's position the June 2020 CPI-U represents a reasonable Test Year escalation factor.

Lastly, using a three-year O&M expense average with a June 2020 CPI-U escalation factor, Staff calculated a Test Year dollar amount of $1.984 million.

Q. What is Staff's recommendation for non-labor O&M Test Year expense?

A. Staff recommends using the three-year average of non-labor O&M expense rather than the non-labor O&M Base Year expense of $2.127 million reported in the Company's responses to Standard Data Requests.[24] The three-year average is $1.984 million, a reduction of ($142 thousand). Additionally, Staff recommends reducing the Company's escalation amount from $59 thousand to $14 thousand, a reduction of ($45 thousand). In total, Staff proposes a ($187 thousand) reduction to the escalated, non-labor O&M Test Year expense.

[24] Based on the Company's non-labor responses to SDR Nos. 057 and 058.

ISSUE 5. A&G EXPENSE (NON-LABOR)

Q. Please describe the expense included in this issue.

A. The Company records A&G expenses in FERC accounts 921 – 922, 928, 930, and 931, and these expenses are allocated between Oregon and Washington operations, with discrete state costs booked 100 percent to the state of operation (situs) or on a fixed percentage allocation basis. In the Base Year, the Company's cost allocation factor for Oregon is 24.83 percent.[25]

Q. Please provide a summary of the Company's filed proposal for this issue.

A. The Company used 2019 A&G non labor expenditures (FERC accounts 921 - 925, 930, 931, and 935) for the Base Year and increased these expenses using an escalation factor. Multiple Staff reviewed various separate components of A&G expenses.

In the Company's revenue requirement model, Cascade used a non-labor Base Year expense for A&G expense. Cascade arrived at this amount using Oregon total 2019 A&G expenditures (FERC accounts 920 - 935) of $6,254,289 and then subtracted $3,240,645 for Base Year salary wages, resulting in a non-labor Base Year amount of $3,013,645. Cascade then escalated the calculated non-labor expense using an escalation rate of 1.8 percent.[26]

[25] See CNGC/305, Peters/1-2.
[26] See CNGC/304, Peters/1, column (k).

For A&G, the Company's workpapers indicate it is requesting non labor A&G escalation of $50,923.[27] Separate from escalation, the Company also proposes adjustments to A&G expenses by removing membership fees (50 percent), officer incentive compensation, adjusted wages, and adjustments for various expenses that are typically disallowed by the Commission, resulting in a reduction of ($245,178) to A&G expenses in the 2020 Test Year.[28]

Q. Please discuss Staff's analysis of these expenditures.

A. Staff used the same review methodology as was used for Distribution O&M expenses. Please see Issue 4 for additional details.

Q. Please summarize Staff's review.

A. Per the Company's response to SDR Nos. 057 and 058, Base Year non-labor A&G expenses were $4.068 million. However, $1.753 million of this total was related to employee pension benefits and $101 thousand were related to rate case expenses.[29] Staff witness Dr. Curtis Dloughy addresses pensions in Exhibit Staff/300 and rate case costs are addressed separately in Issue 10 of my opening testimony. Staff witness Paul Rossow is reviewing other miscellaneous A&G expenses in Exhibit Staff/900. The exclusion of pension and rate case costs results in a revised A&G expense

[27] See CNGC/304, Peters/1, column (k).
[28] See Cascade workpapers, Excel file "UG 390 – Peters MCP-WP1 (Rev Req) 6.19.20 r", tab "Exh 304 – Summary of Adj", Row 30.
[29] Per Company response to Staff SDR No. 057, tab"10-A&G", Column F, Subsidiary "29260", Oregon non-labor pension expenses totaled $29,495 and does not agree with the Company's SDR No. 058 response for non-labor pension expense of $1,753,413. Staff is following up with the Company.

of $2.214 million. From the narrowed A&G data, Staff used the Company's revised response to SDR No. 057 and reviewed two data samples of the 200 largest A&G expenditures, by Oregon situs and by Oregon allocated expense. Staff identified $100,603 in legal and consultant fees associated with the Company's rate case filing and is excluding this amount from Staff's analysis in this issue.

Staff then reviewed three years of summary level non-labor expenses provided in the Company's response to Staff SDR No. 058 and calculated a three-year non-labor average of $2.397 million (2017-2019). Finally, Staff escalated the three-year average, less pensions and rate case expenses, to include the adjusted Base Year, using the June 2020 CPI-U rate of 0.7 percent. This resulted in a Staff calculated Test Year escalation adjustment of $17 thousand and a revised total Test Year amount of $2.414 million.

Q. Did Staff note any differences between the Company's calculations and Staff's calculations for A&G?

A. Yes. First, the Company's calculation for Base Year non-labor A&G expense of $3.014 million is $1.055 million lower than the $4.068 million figure the Company provided in response to SDR No. 058. The Company provided no additional details or documentation to support the $3.014 million figure. As such, it is Staff's position that the $4.068 million amount from the Company's response to SDR Nos. 057 and 058 is better supported than the dollar amount in the Company's revenue requirement inflation factor model. Using the $4.068 million figure above, Staff applied the Company's inflation factor of 1.8 percent to re-calculate the Company's proposed Test Year escalation, resulting in an escalation amount of $41,667, which is $12,579 less than the Company's proposed escalation.

Staff did not consider pension and rate case expenses for this analysis and omitted these dollar amounts from its calculations. This results in a revised Base Year amount of $2.214 million.

Staff then used the June 2020 CPI-U factor of 0.7 percent to calculate Test Year escalation, which is 1.1 percentage points lower than the Company's 1.8 percent escalation used in their filing. In light of the significant decline in economic activity since the beginning of 2020, it is Staff's position that the June 2020 CPI-U represents a reasonable Test Year escalation factor.

Lastly, using a three-year A&G expense average that excluded pension (FERC 926) and rate case expenses (FERC 928) and applying a June 2020 CPI-U escalation factor, Staff calculated a Test Year dollar amount of $2.414 million.

Q. What is Staff's recommendation for non-labor A&G Test Year expense?

A. Staff recommends using a three-year average, thereby increasing the Company's non-labor A&G Base Year expense from $2.214 million[30] to

[30] Based on the Company's non-labor responses to Staff SDR Nos. 057 and 058. This figure excludes pension expense (FERC 926) and rate case expense (FERC 928).

$2.397 million, an increase of $183 thousand. Staff proposes to escalate the revised Test Year using the June 2020 CPI-U of 0.7 percent. This reduces the Company's escalation amount from $54 thousand to $17 thousand, a reduction of ($37 thousand). In total, Staff proposes a $146 thousand increase to the escalated, non-labor A&G Test Year expense. This increase excludes pension and rate case expenses.

ISSUE 6. OTHER TAXES (EXCLUDING INCOME TAXES)

Q. Please provide a summary of the Commission's historical treatment of taxes other than income, the Company's filed proposal, and Staff's analysis of the issue.

A. The category "taxes other than income" (Other Taxes) typically includes franchise fees, the regulatory fee imposed by the OPUC, property taxes, payroll taxes and other miscellaneous taxes or fees, e.g. Oregon Dept. of Energy (ODOE) fee, incurred by the energy utility. Payroll taxes are included as a component of wages and salaries, which is discussed by Staff witness Heather Cohen in Exhibit Staff/200.

Franchise fees, along with business or occupation taxes, licenses, and similar exactions or costs, are allowed as operating expenses for general rates on the condition these costs do not exceed 3.0 percent of gross revenues for a gas utility.[31] For simplicity, these costs are referred to collectively as franchise fees. The OPUC fee and ODOE fee are also included in operating expenses for ratemaking purposes. In rate cases, franchise fees, and the OPUC fee are a function of the fee rate multiplied by gross revenues and are called revenue sensitive costs. Additionally, these revenue sensitive fees are included in the conversion factor in determining the revenue requirement.

[31] See OAR 860-022-0040(1). Fees that exceed three percent must be charged to the customers within the jurisdiction assessing the fee. (OAR 860-022-0040(6)).

Property taxes related to property that is not yet used and useful may not be included in customer rates of a gas utility.[32] Hence, these property taxes are excluded from Test Year operating expenses. Property taxes related to property that is used and useful are included in Test Year operating expense and are usually forecasted for ratemaking purposes based on historical property tax information.

Franchise Fees

Q. What is the Commission's historical treatment of franchise fees in a general rate case?

A. The revenue requirement for franchise fees is revenue sensitive. Accordingly, Staff determines a franchise fee rate based on a ratio of annual fees and revenues. Historically, Staff has accepted a franchise fee rate based on a three-year average rate. However, Staff has reviewed other evidence such as a historical trend to determine the reasonableness of the proposed franchise rate and the resulting franchise fees.

Q. Would you please explain the Company's proposal for franchise fees?

A. The Company did not provide any testimony regarding franchise fees. In CNGC/303, the Test Year franchise rate is reported as 2.412 percent. Staff issued DR No. 230 requesting additional data for franchise fees paid, operating revenues, and the franchise fee percentage for 2016-2019. The

[32] See ORS 757.355(1).

Company's response states the 2.412 percent rate is the franchise fee rate the parties stipulated to for Cascade's last rate case, Docket No. UG 347, Order No. 19-088.

Q. What is Staff's recommendation regarding the franchise fee rate the Company proposes?

A. Staff proposes the franchise fee rate be calculated based on a three-year average of the last three years of actual data (2017-2019). Calculating the franchise fee in this way incorporates another year of data from 2019, thereby updating the rate used in UG 347. This results in 2.372 percent versus the Company's 2.412 percent.[33] The 2.372 percent will be used in the Test Year conversion factor for the revenue requirement and Staff will apply this percentage to adjusted Test Year revenues to calculate the amount of franchises fees in other tax expense.

<u>OPUC Regulatory Fee</u>

Q. Would you please explain the Company's proposal for the OPUC fee?

A. The Company has proposed a rate of 0.300 percent.

Q. Does Staff find the 0.300 percent rate reasonable?

A. No. According to Order No. 20-054, the most recent OPUC order setting the annual fee rate, the rate is set at 0.350 percent.[34] Since this rate is applied to gross revenues, the amount of fees recommended by Staff will be a

[33] See Staff electronic workpaper, UG 390 Exh 100 Issue 1 Franchise Fees wp Gardner.xlsx.

[34] The OPUC budget section is projecting an OPUC regulatory fee assessment of 0.35 percent for April 1, 2021.

function of the amount of gross revenues recommended by Staff in subsequent opening testimony.

Property Taxes

Q. Would you please explain the Company's proposal for Property Taxes?

A. As provided in its response to Staff DR No. 232, the Company included $1.9 million in the Test Year, the actual amount paid in 2019 for property taxes. This results in a property tax factor of 1.48 percent.

Q. What is Staff's recommendation regarding property taxes?

A. Staff reviewed the property tax actuals from 2016 through 2019 in the Company's response to Staff DR No. 232. Based on Staff's review, Staff finds the proposed Test Year property tax expense and property tax factor are reasonable. However, depending on other adjustments to Plant, Staff may propose an adjustment to the final revenue requirement for property tax.

Summary of Other Taxes

Q. What is Staff's recommendation regarding the revenue sensitive rates the Company proposes?

A. Staff recommends an OPUC rate of 0.350 percent in the revenue sensitive conversion factor and a franchise fee rate of 2.372 percent.

Q. Does Staff propose a dollar adjustment(s) for the OPUC fee or franchise fees?

A. At this time, no. These fees are considered revenue sensitive and are best considered once the Company's final Test Year revenues are finalized.

Q. What is Staff's recommendation regarding the Company's proposed Test Year expenses?

A. Both the franchise fees and the OPUC fee are revenue sensitive and are thus a function of revenues. Staff will propose dollar adjustments to both based on other Staff proposals regarding Test Year revenues.

ISSUE 7. MATERIALS AND SUPPLIES INVENTORY AND EXPENSE

Q. Please describe the Commission's historical treatment of "Materials and Supplies" inventory.

A. The utility's inventory of materials and supplies is a subcategory of "working capital" that gas utilities are allowed to include in rate base. The concept is that utilities spend money to keep a store of materials and supplies ready for use and should earn a return on that investment.[35]

Q. What amount is the Company proposing to include in rate base for materials and supplies inventory?

A. The Test Year amount for Oregon is $1.715 million, the same amount in Company's Base Year.

Q. Please discuss Staff's analysis of materials and supplies inventory.

A. Staff reviewed 10 years of end of month inventory data provided in the Company's response to Staff DR No. 222. In particular, Staff focused on the end of year balances as well as the Company's calculated 13-month average of monthly averages (AMA) totals for each year.

Q. What is the three-year average for materials and supplies inventory?

A. Staff used the Company's 13-month AMA methodology from the Company's response to DR 222 to cross check the Company's AMA annual averages calculations for 2017-2019. Staff then calculated a

[35] See e.g., *In re California-PacifiCorp Utilities Company* (Docket No. UF 3195), Order No. 76-132 (1976 WL 419251).

three-year and two-year annual AMA average for comparison against the Company's Base Year amount. The proposed Test Year amount of $1.715 million is less than the three-year average AMA of $2.229 million and the two-year average AMA of $2.124 million.[36] From 2017 to 2019, the dollar amount for Cascade's materials and supplies inventory have steadily declined. Staff did not identify any concerns regarding materials and supplies inventory.

Q. Please discuss Staff's review of Base Year materials and supplies expense.

A. In the Company's response to SDR No. 057, Staff identified A&G materials and supplies expenses of $7 thousand and Distribution O&M materials and supplies expenses of $400 thousand. Staff's review of these transactions revealed no issues or concerns. Please see Staff Issues 4 and 5 for a more in-depth description of Staff's review of A&G and Distribution O&M expenses.

Q. Does Staff propose to adjust the Company's Test Year materials and supplies inventory or projected expenses?

A. Staff proposes no adjustment.

[36] 2017-2019 dollar amounts provided in Company's response to Staff DR No. 222, Excel file "OPUC-222 Rate Base 2019". The Company also provided Excel files for 2011-2018.

ISSUE 8. PREPAID EXPENSE

Q. What are prepaid expenses and how are they recorded?

A. Prepaid expenses are payments made in advance for items such as yet-to-be delivered gas, insurance, rent, and taxes. As the periods covered by prepayments expire, the value of these prepayments is reduced and the associated expense is charged to the proper operating account. Prepaid expenses are recorded in FERC account 165.[37]

Q. Did the Company include prepaid expenses in the rate case?

A. In response to Staff SDR No. 085, the Company provided data for three separate categories of prepayments included in the rate case. The Company proposes to include in the Test Year prepayments for insurance of $34 thousand, gas storage of $962 thousand, and miscellaneous of $242 thousand.

Q. Please discuss Staff's review of this issue.

A. The components for gas storage and miscellaneous prepayments were previous addressed in Staff Issues 1, 7, and 8 and are excluded here, with one exception. In Staff's review of gas storage in rate base, the Company provided detailed documentation in support of $643 thousand for prepaid gas storage expense in their response to Staff DR No. 222.

Regarding prepaid insurance expense, Staff noted a discrepancy between the Oregon allocated Base Year dollar amount of $34 thousand provided in the Company's response to SDR No. 085 and total Oregon Base Year

[37] See 18 C.F.R. § 205 (FERC account 165).

expenditures recorded as “prepaid insur exp” of $338 thousand provided in the Company’s response to SDR No. 057. Staff is requesting the Company provide additional clarification for the $304 thousand difference.

Q. Does Staff recommend and adjustment for this issue?

A. At this time, no. However, Staff’s investigation of this issue is ongoing and Staff reserves the right to make an adjustment at a later date.

ISSUE 9. RATE CASE EXPENSE

Q. Please describe the expense at issue.

A. The Company incurred additional expenses associated with filing this rate case. In addition to Company staff, the Company used an outside law firm and a consulting firm to provide additional support in their rate case filing.

Q. Please provide a summary of the Company's proposal for this issue.

A. The Company reported total costs for outside contractors used on the present rate case, as well as continued amortization from prior rate case expenses, is $356,495 for the Base Year.[38] The Company proposes to use the equivalent of a three-year amortization for rate case costs in the present filing, and included this expense in the 2020 Test Year. Additionally, the Company included unamortized expense from two prior rate cases, $89,670 from Docket No. UG 347 and $11,275 from Docket No. UG 287. In total, the Company proposes to include rate case costs of $178 thousand in the 2020 Test Year.

Q. Please explain the Staff's typical treatment for rate case costs.

A. Staff's historical treatment of rate case costs is to review these costs for reasonableness. Rate case costs that are deemed reasonable are then accounted for in the utility's Test Year as if they are being amortized over a multi-year period, typically three years. This means only one-third of the rate case costs are included as Test Year expense. Including one-third of

[38] See Cascade workpapers, Excel file "UG 390 – Peters MCP-WP1", tab "Rate Case Costs".

the costs reflects that utilities do not typically file a rate case every year. Although Staff describes the rate treatment as amortization, the Company does not separately amortize rate case costs. Instead, they are another component of the Test Year. This methodology was used in the Company's three prior rate cases.[39]

Q. Please describe Staff's analysis of the Company's proposal for rate case costs.

A. Staff analyzed Company's Exhibits 301-306 and Peters Excel worksheet "UG 390 – Peters MCP-WP1", tab "Rate Case Costs".[40] Per Ms. Peter's workpaper, no rate case costs were incurred in the Base Year. As a result, the Company proposes an estimated Test Year adjustment of $178,055 to reflect current rate case expenses as well as continuing amortized expensed from prior rate cases.

In the previous three rate cases, Staff treated rate case costs in the Test Year as if they were amortized over a three-year period. In Docket No. UG 305, the Test Year rate case expense in the Test Year was $95,724. In Docket No. UG 347, the Test Year rate case expense was $89,670.

Q. Does Staff have concerns with the Company's proposed Test Year expense for rate cases?

[39] *In the Matter of Cascade Natural Gas Corporation* (Docket No. UG 347), Order No. 19-088; *In the Matter of Cascade Natural Gas Corporation* (Docket No. UG 305), Order No. 16-477; *In the Matter of Cascade Natural Gas Corporation* (Docket No. UG 287), Order No. 15-412.
[40] Additional details provided in CNGC/304, Peters/1, Column (n).

A. Yes. First, the Company's inclusion of "unamortized" expense from previous rate cases is not appropriate. As with any other expense, the Company is not guaranteed that its revenues will exactly match its expenses. The fact that Cascade believes it has not yet recovered its costs from previous rate cases does not mean that it is appropriate to include those previous costs in the Test Year for this case.

Second, Staff notes the Company proposes to amortize rate case expenses related to Concentric over five years rather than a three-year period. The Company did not provide additional testimony or supporting documentation as to why a five-year amortization is preferable to Staff's practice of using a three-year amortization period.[41]

Q. Does Staff recommend an adjustment to the proposed 2020 Test Year?

A. Yes. Staff recommends an adjustment of ($100,945) to remove expenses associated with previous rate cases. Staff also recommends the proposed Concentrix expense of $60,550 in the present filing be amortized over a three-year period instead of a five-year period, resulting in a Test Year increase of $8,073. In total, Staff recommends a net adjusted Test Year rate case expense of $85 thousand, a ($93 thousand) reduction to the Company's proposed Test Year rate case expense.[42]

[41] Based on the Company's recent Oregon rate case history, the Company files rate cases approximately once every two years. Docket No. UG 305 filed April 4, 2016; Docket No. UG 347 filed May 31, 2018; and Docket No. UG 390 was filed March 31, 2020.
[42] UG 305 Test Year 2016 amortized rate case expense = $95,724; UG 347 Test Year 2018 amortized rate case expense = $89,670.

ISSUE 10. CASCADE'S CONVERSION RATE CALCULATION

Q. Please summarize Staff's review of this issue.

A. In the Company's original filing, Cascade's revenue requirement model Excel workpaper "UG 390 - Peters MCP-WP1", Tab "Revenue Sensitive Cost Calc", and supporting exhibits CNGC/302, Peters/1 and CNGC/303, Peters/1, contain an error in the calculation for Oregon state income tax. This error in turn affects the Company's calculation of Federal taxable income and the subsequent calculated percentage for total excise taxes and the total revenue sensitive cost factor.

Q. Please describe the error and how Staff proposes to correct the calculation.

A. For the purposes of revenue modeling for Oregon taxable income, revenue sensitive items (e.g. uncollectible accounts, OPUC fee, franchise fees) must first be deducted from a revenue factor of 1. The resultant percentage is the Company's Oregon taxable income. The Oregon taxable income should then be multiplied by the State income tax rate of 7.6 percent to derive Federal taxable income.

In the Company's revenue requirement model,[43] Cascade's calculation for Oregon state income tax subtracts 7.6 percent from the Oregon taxable income factor. The Company should have instead multiplied state taxable income by 7.6 percent. By subtracting the Oregon state tax rate from

[43] See Cascade Excel workpaper "UG 390 - Peters MCP-WP1", Tab "Revenue Sensitive Cost Calc", Rows 11-23.

Oregon taxable income instead of multiplying, the Company's Federal taxable income is too low compared to Staff's revenue model. As a result, the Company's Federal tax rate, total excise tax rate, total revenue sensitive costs, and utility operating income factors are too low compared to Staff's revenue model. The Company's filed net-to-gross up factor of 1.41675 is overstated, which affects every dollar of additional revenue. The following table compares Cascade's and Staff's calculations.

Table B [44]

		Company		Staff
REVENUE SENSITIVE COSTS				
Revenues		1		1
Operating Revenue Deductions				
Uncollectible Accounts		0.00340668		0.00340668
Taxes Other - Franchise & Resource Supplier		0.02412400		0.02412400
OPUC Fees		0.00300000		0.00300000
State Taxable Income		0.96946932		0.96946932
State Income Tax		0.07600000		0.07367967
Federal Taxable Income		0.89346932		0.89578965
Federal Income Tax @ 21%		0.18762856		0.18811583
ITC		0.00000000		0.00000000
Current FIT		0.18762856		0.18811583
Other				
Total Excise Taxes		0.26362856		0.26179549
Total Revenue Sensitive Costs		0.29415924		0.29232618
Utility Operating Income		0.7058407607283		0.70767382
Net-to-Gross Factor		1.41675014		1.41308039

[44] Staff workpapers, Excel file "UG 390 Exh 100 Opening Testimony Staff's Model Rev Req wp CONF", Tab "Revenue Sensitive Cost Calc".

Q. Does Staff propose an adjustment to the Company's Conversion Rate calculation?

A. Yes. Staff re-calculated the Company's Oregon state income tax component, which results in a revised net-to-gross factor of 1.41308.

Q. Does Staff propose a dollar adjustment to the Company's conversion rate?

A. No. Staff's proposed decrease to Cascade's conversion rate and net-to-gross factor will impact the calculated revenue requirement required for the authorized ROR on final rate base.

ISSUE 11. INTEREST RATE SYNCHRONIZATION & COST OF CAPITAL STIPULATION

Q. Please provide a summary of the Commission's historical treatment of interest synchronization, the Company's filed proposal, and Staff's analysis of the issue.

A. According to long-standing Commission policy, for ratemaking purposes, Staff routinely synchronizes interest expense to reflect changes in the regulated utility's cost of capital as initially filed in a general rate case. Accordingly, the interest synchronization adjustment depends on proposed adjustments to cost of capital (CoC) in this docket. In this case, all parties have resolved cost of capital issues raised and filed a stipulation to that effect on July 1, 2020. The Stipulation, if approved by the Commission, will impact the Company's filed cost of capital, of which the weighted cost of debt is a component. Because interest expense on long-term debt is tax deductible, the proposed cost of long-term debt (LTD) impacts income tax expense for ratemaking purposes.

The cost of long-term debt proposed in Cascade's direct testimony is 4.750 percent, with a weighted cost of long-term debt of 2.375 percent. According to the Stipulation, the agreed upon cost of long-term debt is 4.741 percent, with a weighted cost of long-term debt of 2.371 percent.

Q. What is the revenue requirement impact of the stipulated change to CoC?

A. In the Stipulation, the parties did not calculate the revenue requirement impact. The only component that did change was the cost of LTD. Therefore, Staff did include the revenue requirement impact of both the CoC and interest synchronization in the model.

Q. What is Staff's recommendation for interest expense?

A. As the revenue requirement summary witness, I have synchronized the interest expense for the income tax calculation to reflect the stipulated weighted cost of debt of 2.371 percent. Calculated on the Company's Test Year rate base of $132,613,684 and its filed weighted cost of long-term debt of 2.375 percent, I recommend a reduction to interest expense for income tax purposes of ($5,305). The exact of amount of the adjustment will be trued-up as a function of the final agreed upon Net Rate Base.

The interest amount is calculated on the Test Year as follows:

+ Net Rate Base

X Staff's Recommended (or Authorized) Weighted Cost of Debt

= Allowable Interest Deduction

- Company's Reported Interest Deduction

= Interest Coordination Adjustment

Q. What is Staff's recommendation for the revenue requirement impact of July 1, 2020, Cost of Capital Stipulation?

A. I have proposed a reduction in the revenue requirement of $7,496 for Cost of Capital and an increase of $2,024 for Interest Synchronization for a total decrease of $5,472.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Brian Fjeldheim
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance, and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Science, Business Accountancy Regis University, Denver, CO Bachelor of Science, Aviation Technology Metropolitan State College of Denver, Denver, CO

EXPERIENCE:

I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since May of 2018 in the Energy, Rates and Finance Division. I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on rate case, operational audit, and annual Purchased Gas Adjustment (PGA) filings. I have participated in utility general rate cases in the following dockets: Cascade Natural Gas – UG 347, Avista Utilities – UG 366, NW Natural – UG 388 (pending), PacifiCorp – UE 374 (pending), Avista Utilities – UG 389 (pending), and Cascade Natural Gas – UG 390 (pending).

I have seven years of professional level financial analysis and accounting experience. I was previously employed as a Budget and Fiscal Analyst with the Oregon Department of Justice (DOJ), where I was responsible for the budget build and ongoing budget execution of four legal divisions with 165 staff members and a biennial budget of $75 million. Prior to DOJ, I was employed as a Senior Budget Analyst with the Oregon Department of Administrative Services (DAS) and was responsible for the budget build, ongoing budget execution and cash flow analysis for the state data center with a biennial budget of $165 million. Prior to DAS, I worked as a Financial Analyst for the Insurance Division of the Department of Consumer and Business Services (DCBS), where I performed financial analysis and solvency surveillance of nine Oregon insurers with annual revenues of $1.4 billion and assets of $1.1 billion.

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
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STAFF EXHIBIT 102

Exhibits in Support
Of Opening Testimony

July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 221

Date prepared: 6/26/2020

Preparer: Brian Hoyle

Contact: Chris Mickelson

Telephone: (509)-734-4549

221. Please provide, in a single electronic spreadsheet format:

a. Monthly historical working gas inventory balances (excluding labor dollars) for each storage facility (in both volume and in dollars) and the monthly working gas storage guideline, or goal or target, for each storage facility (in the same volume units as used for the inventory). Please include the monthly data requested above for each storage facility from 2010 to 2019, and to the extent as available monthly through 2020. Please indicate whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2010 through 2019, and to the extent as available monthly through 2020. Provide results separately for total company and for Oregon; and

b. Historical cushion gas inventory balances for each storage facility (in both volume and in dollars), by month from 2010 to 2019, and to the extent as available monthly through 2020. For the dollar values provided, please provide an explanation as to how the dollar value was derived. Please indicate whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2010 through 2019, and to the extent as available monthly through 2020. Provide results separately for total company and for Oregon.

Response:

CNGC does not own and operate a gas storage facility.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 222

Date prepared: 6/23/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

222. Does the Working Capital balance exclude Gas Inventory from Rate Base? If no, please provide:
   a. A description of Working Capital as it relates to Gas Inventory in Rate Base; and
   b. The monthly historical Working Capital balances (excluding labor dollars) for each storage facility. Provide the monthly data requested above from 2010 to 2019, and to the extent as available monthly through 2020. Please indicate whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2010 to 2019, and to the extent as available monthly through 2020. Provide results separately for total company and for Oregon.

Response:

a) Working capital in OR is primarily Materials and Supplies and Gas Inventories. These are the things that are prepaid by the shareholders for use by customers later.

b) See attached Excel Spreadsheets:
OPUC-222 – Rate Base 2011.xlsx
OPUC-222 – Rate Base 2012.xlsx
OPUC-222 – Rate Base 2013.xlsx
OPUC-222 – Rate Base 2014.xlsx
OPUC-222 – Rate Base 2015.xlsx
OPUC-222 – Rate Base 2016.xlsx
OPUC-222 – Rate Base 2017.xlsx
OPUC-222 – Rate Base 2018.xlsx
OPUC-222 – Rate Base 2019.xlsx
OPUC-222 – Rate Base 2020.xlsx

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 103

Exhibits in Support
Of Opening Testimony

July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 220

Date prepared: 6/26/2020

Preparer: Brian Hoyle

Contact: Chris Mickelson

Telephone: (509)-734-4549

220. Please provide, in a single electronic spreadsheet format, for each calendar year from 2010 through 2019, and to the extent available monthly through 2020, the underground storage operating expense results, including a breakdown of the underground storage operating expense into supervision and engineering, other expenses, and other equipment categories. Separately identify any related labor expense for each calendar year from 2010 through 2019, and to the extent available monthly through 2020. Provide results separately for total company and for Oregon.

Response:
CNGC does not own and operate a gas storage facility.

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 104

Exhibits in Support
Of Opening Testimony

July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 219

Date prepared: 06/22/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

219. Please provide, in a single electronic spreadsheet format, for each calendar year from 2010 through 2019, and to the extent available monthly through 2020, the other gas supply expense results, as well as a breakdown of the other gas supply expense into other gas purchases, purchased gas expenses, natural gas storage transactions, gas used for products extraction, other gas expenses, and Gas Technology Institute categories. Separately identify any related labor expense for each calendar year from 2010 through 2019, and to the extent available monthly through 2020. Provide results separately for total company and for Oregon.

Response:

See Excel Spreadsheet OPUC-219.xlsx

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 105

Exhibits in Support
Of Opening Testimony

July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 225

Date prepared: June 23, 2020

Preparer: Becky Hodges Mellinger

Contact: Chris Mickelson

Telephone: (509)-734-4549

225. For the Company's 2018, 2019, and 2020 budget periods, please provide a description of the budget parameters provided by the executive group to Cascade's managers and directors used in developing the approved annual budget.

Response:

O&M Expenditures

Cascades standard budgeting process and guidelines for O&M Expenditures are as follows:

In the PowerPlan budgeting system, each person responsible for department budgeting has access to budget entry screens and reports. Budgeter's update the information utilizing system generated actual vs budget reports and anticipated changes to the next years' operating structure.

<u>Labor line items</u> are pre-loaded with current employee positions, anticipated merit increases, and current pay rates. Positions currently unfilled are identified and added to the detailed individual labor screens. The individual employee information is then consolidated by the system at the business unit level, allocating wages between Capital and O&M as needed.

<u>Non-Labor line items</u> are pre-filled with current year approved budget, current year 5&7 Proforma estimates, and prior year 12-month actual spending information. Budgeters update each individual business units line items with anticipated spending for the budget year.

Expenses are then consolidated and reviewed by the Executive team at the functional level (Accounting, Operations, HR, for example). Non-labor line items in total are asked to be held to variances of no more than a specified percentage over the 5&7 proforma amount at the consolidated level.

Variances over this level are to have explanations available outlining the business need and associated costs for the overrun.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 226

Date prepared: June 23, 2020

Preparer: Becky Hodges Mellinger

Contact: Chris Mickelson

Telephone: (509)-734-4549

226. Please provide a comparison of the 2018 approved budget to 2018 actual results, by budgeted line item.

Response:
See Attached PDF **-** OPUC-226 - 2018 O&M Actuals to 2018 Budget

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 227

Date prepared: June 23, 2020

Preparer: Becky Hodges Mellinger

Contact: Chris Mickelson

Telephone: (509)-734-4549

227. Please provide a comparison of the 2019 approved budget to 2019 actual results, by budgeted line item.

Response:

See Attached PDF - OPUC-227 - 2019 O&M Actuals to 2019 Budget

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 228

Date prepared: June 23, 2020

Preparer: Becky Hodges Mellinger/Kevin Conwell

Contact: Chris Mickelson

Telephone: (509)-734-4549

228. When executing an approved budget, please describe how Cascade monitors and analyzes variances between budgeted and actual revenues and expenditures.

Response:

O&M Expenditures
Monthly, as part of the closing process a Financial Analyst prepares a schedule showing variances for:

Business Unit Roll-up Level (Business Development, Accounting, Operations, etc.)
- Current month actual expense to same month actual expense of the prior year
- Current month actual expense to "Plan" or budgeted expense for the corresponding month

Object Line Item Roll-up Level (Payroll, Benefits, Software Maintenance, etc.)
- Current month actual expense to same month actual expense of the prior year
- Current month actual expense to "Plan" or budgeted expense for the corresponding month

Material variances are researched by the Analyst. Variances are categorized as either due to timing of expenditure or a permanent change in estimate. These are noted in the Financial summary packet and reviewed as part of the monthly Earnings Review meetings.

Quarterly, the Budgeting Analyst looks at both actual and trends in expense variances. For significant variances, both over and under planned levels, the Budget Analyst works with the appropriate personnel to see if the variance is due to timing of expenses, change in estimate, and for other changes to anticipated spending levels for the remaining budget year.

Changes in estimate/timing of expenses for the remaining forecasted month are compiled into a "net" adjustment amount to O&M expenditures. Based upon materiality, the net adjustment amount is entered in the forecasting software as an adjustment to forecast period.

Other costs/revenues

Quarterly or as available throughout the year the information is updated for the forecasted period based upon updated estimates or known changes.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Examples of items routinely updated are:

- Rates due to Regulatory filings
- Customer usage projections (plant shutdowns for example)
- Actuary Calculations
- Interest Rate Updates
- Tax/Book Depreciation estimates
- Tax payment, change in tax assumptions
- Capital Expenditures & related costs (depreciation, AFUDC, etc.)
- Dividend declarations
- Bonus/Incentive Projections
- Volume fluctuations due to warmer/colder weather than normal and the effects of decoupling

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 229

Date prepared: June 22, 2020

Preparer: Becky Hodges Mellinger/Kevin Conwell

Contact: Chris Mickelson

Telephone: (509)-734-4549

229. Referencing the data request immediately above, does Cascade have defined budget variance tolerance levels for specific revenue or expenditure categories?
    a. If yes, please include a brief description of how each variance tolerance threshold is developed.
    b. If actual expenditures exceed budget variance tolerances without a commensurate increase in revenues, please describe the process for re-aligning expenditures to budgeted levels.

RESPONSE:

a. Cascade does not have a predetermined variance tolerance threshold. Variances are investigated with regards to volatility, materiality, time within the 12-month budget cycle, etc.
b. Operating budgets as discussed in DR #223 are analyzed on a monthly basis to determine if CNG will experience any significant cost overruns. If there are projects/costs incurred for any unplanned circumstances then other planned projects/costs will be identified and a decision made on if those projects/costs can be delayed or pushed out until the next year to compensate for the unplanned overruns.

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 106

Exhibits in Support
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July 30, 2020

From Cascade workpapers, Excel file "UG 390 - Peters MCP-WP1", Tab "Inflation Factor"

Cascade Natural Gas Corporation
Inflation Factor
UG 390
Twelve Months Ended December 31, 2019

	Base Year Amounts	Base Year Wages		2020 Projected CPI	
Production	$110,976.86		$110,976.86	0.018	$ 1,997.58
Distribution	$6,651,690.76	$ 3,367,458.4	$3,284,232.32	0.018	$ 59,116.18
Customer Accounts	$1,907,205.72		$1,907,205.72	0.018	$ 34,329.70
Customer Service	$0.00		$0.00	0.018	$ -
Administrative and General	$6,254,289.49	$ 3,240,644.7	$3,013,644.84	0.018	$ 54,245.61
					$ 149,689.08

2019 System Salary Wages	$ 12,988,555.72	24.95%	$ 3,240,644.65
2019 System Union Wages	$ 13,496,827.40	24.95%	$ 3,367,458.44

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 107

Exhibits in Support
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July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 230

Date prepared: June 23, 2020

Preparer: Maryalice Peters

Contact: Chris Mickelson

Telephone: (509)-734-4549

230. Regarding the Excel work paper titled "MCP-WP1 (rev Req)", workbook tab "Exh 303 - Conversion Factor", please provide:

   a. The methodology used to derive the Company's Taxes Other - Franchise Fee percentage of 2.412 percent (reported on Excel row 9, Column D).

   b. All electronic work papers, will cell formulas intact, used to calculate the Franchise Fee percentage for the Test Year.

   c. Oregon franchise fee expense and Oregon allocated revenue data for 2016 to 2019.

Response:

a. 2.412 percent was settled in the last rate case UG-347, Order no. 19-088.
b. No calculations to arrive at 2.412 percent. The parties in last rate case UG-347, agreed to compromise the percentage.
c. See attached OPUC-230.xlsx.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 231

Date prepared: June 23, 2020

Preparer: Maryalice Peters

Contact: Chris Mickelson

Telephone: (509)-734-4549

231. Does Cascade include a provision for property taxes in their revenue sensitive conversion factor? If yes, please provide:
    a. The location within the Company's work papers.
    b. The methodology used to derive the Company's Test Year property tax percentage.
    c. All electronic work papers, will cell formulas intact, used to calculate the property tax percentage.

Response:

Cascade does not include a provision for property taxes in revenue sensitive conversion factor.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 232

Date prepared: June 22, 2020

Preparer: Lauri M Wavra

Contact: Chris Mickelson

Telephone: (509)-734-4549

232. Please provide 2016 - 2019 Oregon specific property tax data for Cascade, to include:

a. The Company's annual assessed property value.
b. The Company's annual gross property tax expense.
c. The Company's effective property tax rate percentage

Response:

2016 – a) $93,900,000
b) $1,391,926.29
c) 1.48%

2017 – a) $105,000,000
b) $1,561,364.94
c) 1.49%

2018 – a) $114,400,000
b) $1,702,976.17
c) 1.49%

2019 – a) $128,200,000
b) $1,899,871.48
c) 1.48%

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
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Exhibits in Support
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July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 222

Date prepared: 6/23/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

222. Does the Working Capital balance exclude Gas Inventory from Rate Base? If no, please provide:
    a. A description of Working Capital as it relates to Gas Inventory in Rate Base; and
    b. The monthly historical Working Capital balances (excluding labor dollars) for each storage facility. Provide the monthly data requested above from 2010 to 2019, and to the extent as available monthly through 2020. Please indicate whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2010 to 2019, and to the extent as available monthly through 2020. Provide results separately for total company and for Oregon.

Response:

a) Working capital in OR is primarily Materials and Supplies and Gas Inventories. These are the things that are prepaid by the shareholders for use by customers later.

b) See attached Excel Spreadsheets:
OPUC-222 – Rate Base 2011.xlsx
OPUC-222 – Rate Base 2012.xlsx
OPUC-222 – Rate Base 2013.xlsx
OPUC-222 – Rate Base 2014.xlsx
OPUC-222 – Rate Base 2015.xlsx
OPUC-222 – Rate Base 2016.xlsx
OPUC-222 – Rate Base 2017.xlsx
OPUC-222 – Rate Base 2018.xlsx
OPUC-222 – Rate Base 2019.xlsx
OPUC-222 – Rate Base 2020.xlsx

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 109

Exhibits in Support
Of Opening Testimony

July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 222

Date prepared: 6/23/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

222. Does the Working Capital balance exclude Gas Inventory from Rate Base? If no, please provide:
    a. A description of Working Capital as it relates to Gas Inventory in Rate Base; and
    b. The monthly historical Working Capital balances (excluding labor dollars) for each storage facility. Provide the monthly data requested above from 2010 to 2019, and to the extent as available monthly through 2020. Please indicate whether the values given above are for beginning or end of month. Separately identify any related labor expense for each calendar year from 2010 to 2019, and to the extent as available monthly through 2020. Provide results separately for total company and for Oregon.

Response:

a) Working capital in OR is primarily Materials and Supplies and Gas Inventories. These are the things that are prepaid by the shareholders for use by customers later.

b) See attached Excel Spreadsheets:
OPUC-222 – Rate Base 2011.xlsx
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OPUC-222 – Rate Base 2016.xlsx
OPUC-222 – Rate Base 2017.xlsx
OPUC-222 – Rate Base 2018.xlsx
OPUC-222 – Rate Base 2019.xlsx
OPUC-222 – Rate Base 2020.xlsx

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

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STAFF EXHIBIT 110

Exhibits in Support
Of Opening Testimony

July 30, 2020

* From Cascade workpapers, Excel file "UG 390 - Peters MCP-WP1", Tab "Rate Case Costs"

Cascade Natural Gas Corporation
RATE CASE COSTS
UG 390
Twelve Months Ended December 31, 2019

	Company 2020 Test Year Expense	Oregon %	Oregon Total	Amortization Periods (yrs)		
Black & Veatch	$45,000	100.00%	$45,000	3		$15,000
Concentric	$60,550	100.00%	$60,550	5		$12,110
McDowell Rackner	$150,000	100.00%	$150,000	3		$50,000
Previous Case - UG 347 (Remaining Rate Case Cost)	89,670	100.00%	$89,670	1		$89,670
Previous Case - UG 287 (Remaining Depn & Load Studies)	$11,275	100.00%	$11,275	1		$11,275
Rate Case Costs					$	178,055
Amount already included in 2018 base year					$	-
Total Rate Case Cost					$	178,055

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
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STAFF EXHIBIT 111

Exhibits in Support
Of Opening Testimony

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UG 390 Staff Opening Testimony

Cascade Natural Gas
Test Year Ending December 31, 2020
000's of Dollars

See Staff/Fjeldheim, 100. Correct Company's Conversion Factor & NTG for incorrect modeling of State Income Tax. Note that Company subtracted the State Income Tax Rate on line 8 rather than multiply taxable income by the State Income Tax Rate. This adjustment does not take into account the other revenue sensitive factors that other Staff mav have reviewed.

	Company Filing		**Staff Proposal**			**Staff Adjustment Conversion Factor**	**Staff Adjustment Incremental Revenue Requirement**
	(See CNG Exhibit 303)						
1	Revenues	1.00000	Revenues	1.00000			$ (11,676.50)
2	Operating Revenue Deductions		Operating Revenue Deductions				
3	Uncollectible Accounts	0.003406683	Uncollectible Accounts	0.003406683			$ (39.78)
4	Taxes Other - Franchise	0.024124000	Taxes Other - Franchise	0.024124000			$ (281.68)
5	OPUC Fees	0.003000000	OPUC Fees	0.003000000			$ (35.03)
6	Interest expense		Interest expense				
7	State Taxable Income	0.96947	State Taxable Income	0.96947			$ (11,320.01)
8	State Income Tax	0.07600	State Income Tax	0.07368		0.00232	$ (860.32)
9	Federal Taxable Income	0.893469317	Federal Taxable Income	0.895789649		-0.00232	$ (10,459.69)
10	Federal Income Tax @ 21%	0.18763	Federal Income Tax @ 21%	0.18812		-0.00049	$ (2,196.53)
11	Total Taxes	0.26363	Total Taxes	0.26180		0.00183	$ (3,056.86)
12	Total Revenue Sensitive Costs	0.29416	Total Revenue Sensitive Costs	0.29233		0.00183	$ (3,413.35)
13	Net-to-Gross*	**0.70584**	Utility Operating Income	**0.70767**		-0.00183	**$ (8,263.15)**
14		**1.41675**	Net-To-Gross	**1.41308**		**0.00367**	**1.41308**
15	**Combo-State & Federal Income Tax**						
16	State	0.07600		0.07600			0.07600
17	Federal	0.21000		0.21000			0.21000
18	State and Federal Effective Tax Rate	0.27004		0.27004			0.27004
19	Additional taxes added to Incremental Rev Req Tax calc	8,264					(8,264)

Note* The Company names this factor Net-to-Gross in Exhibit 303 but also calls it Conversion Rate in Exh 302. Staff names it Utility Operating Income as this is what it actually represents. It is the next calculation that provides the factor that is applied Operating Net Income and grosses it up to the Revenue Requirement. Hence the factor on line 14 Staff has correctly named Net-to-Gross.

Staff Initiator:
Brian Fjeldheim

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

(See CNG Exhibit 302)

		Company	Staff Proposal	Staff Rev Req Adjustment
1	Adjusted Rate Base	$132,613,684.2560860	$132,613,684.2560860	
2	Rate of Return	7.075000%	7.075000%	
3	Required Return (ln 1 x ln 2)	$9,382,418.16112	$9,382,418.16112	
4	Adjusted Net Income	$6,200,600	$6,200,600	
5	Required Net Income Increase (ln 3 - ln 4)	$3,181,819	$3,181,819	
6	Conversion Factor	0.70584076073	0.70767382291	
7	Revenue Increase Required (ln 5 / ln 6)	**$4,507,841.932569**	**$4,496,165.430890**	**-$11,676.501678**
8	Test Year Adjusted Revenue	$67,578,196	$67,578,196	
9	Overal Revenue Increase	**6.671%**	**6.653%**	
10	Exh. 306 Environmental Rem. Revenue Increase	$ 363,765	$ 363,765	
11	Total Revenue Increase	$4,871,607.15570	$4,859,930.65403	
12	Total Increase	7.209%	7.192%	

CASE: UG 390
WITNESS: BRIAN FJELDHEIM

PUBLIC UTILITY COMMISSION
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OREGON

STAFF EXHIBIT 112

Exhibits in Support
Of Opening Testimony

July 30, 2020

Cascade Natural Gas
STAFF ISSUE SUMMARY
Twelve Months Ended December 31, 2019

CNG requested Incremental Revenue Requirement							**$ 4,507,842**
Opening Testimony Exhibit No.	**Staff Witness**	**Issue No.**	**Issue Description**	**Revenue**	**Expense**	**Rate Base**	**Incremental Revenue Requirement Effect**
Stipulation	Muldoon		Stipulated Cost of Capital				$ (7,496)
100	Fjeldheim	10	Company Conversion Rate*				
100	Fjeldheim	11	Interest Sync				2,024
Total Staff-Proposed Adjustments (Base Rates):				$ -	$ -	$ -	$ (5,472)
Staff-Calculated Revenue Requirements Change (Base Rates):							$ 4,502,370

* Note - No Incremental Revenue Requirement Effect included for Conversion Rate change in Table A. Staff's proposed decrease to CNG's conversion rate and NTG factor will impact calculated revenue requirement required for authorized ROR on final rate base. Staff's proposed decrease to the conversion rate and NTG factor on the Company's filed case reduces Total Revenues by $11,677 & Expenses by $11,677, which nets to $0. See Staff Excel workpaper, UG 390 Exh 100 Staff's Model adjusting CNG Conv Factor WP.xlsx, Summary tab, col 10.

CASE: UG 390
WITNESS: HEATHER B.COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 200

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Heather Cohen. I am a Senior Utility Analyst employed in the Energy Rates and Accounting Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. I provide background, analysis, and recommendations regarding the Company's Test Year expense for wages, salary, incentives, full-time equivalents, and uncollectibles. I also address Staff's adjustments to advertising and customer account and customer service expenses.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/202, Company responses to Staff Data Requests, as well as Exhibit Staff/203, the June 2020 All-Urban CPI Index.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. SALARIES AND WAGES

Q. Please provide a summary of the Commission's historical treatment of wages, salaries, incentives, and overtime expense.

A. The Commission has relied on Staff's three-year wage and salary (W&S) model to estimate union and non-union payroll levels for energy utilities.[1] The W&S model ties the increases in payroll from a historic base year to the rate of inflation using the All-Urban CPI.[2] As a starting point for non-union wages, Staff's model uses the utility's actual average wage and salary levels as they existed three years prior to the Test Year. From there, Staff applies the annual changes to the All-Urban CPI to adjust wages and salaries for each of the three subsequent years to establish a forecast of Test-Year wage and salary levels. Then, the sharing principle is applied, wherein Staff allows the Company to share 50/50 the lesser of the difference between the model forecast and the amount the Company has included in its Test Year, or a 10 percent band around Staff's projection.

The W&S model incorporates actual market-based data by using historic wages and adjusting for inflation using the All-Urban CPI index.[3] The Commission has consistently validated the All-Urban CPI to adjust historic wages and salaries as "adjusting payroll levels by changes in inflation provides

[1] *In the Matter of Northwest Natural*, Docket UG 132, Order No. 99-697 at 43 (November 12, 1999).
[2] See *Pacific Power & Light,* UE 116, Order 01-787 at 40; In the Matter of Northwest Natural, Docket UG 132, Order No. 99 697 at 43 (November 12, 1999); *In the Matter of PGE*, Docket UE 102, Order 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, Docket UE 88, Order No. 95-322 at 10 (March 29, 1995).
[3] See Order No. 99-697 at 43.

employees the same real level of compensation as in the base year and provides an incentive to companies to minimize labor costs."[4] Moreover, the All-Urban CPI captures local economic conditions as the Bureau of Labor Statistics includes Oregon prices in its survey.[5] Further, Staff's methodology of equally dividing between ratepayers and shareholders the difference between the utility's Test Year forecast and the forecast obtained by the model allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[6]

For union wages, Staff again starts with actual wages three years before the Test Year. Rather than escalating the wages using All-Urban CPI, Staff escalates using negotiated wage increases as set forth in union contracts, and then applies the sharing component between the Company's Test Year forecast and the forecast obtained under the W&S model.[7]

For incentives, the Commission's policy is to disallow 100 percent of officers' bonuses because they are typically based on increased earnings, which benefits shareholders.[8] It is also Commission policy to disallow 75 percent of performance-based bonuses (because they are generally focused on increased earnings and, therefore, bring more benefit to shareholders), and to disallow 50 percent of merit-based bonuses (because they equally benefit

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[4] See Order No. 99-697 at 43.
[5] See Order No. 99-697 at 43.
[6] Order No. 95-322 at 10.
[7] See Order No. 99-697 at 43.
[8] See Order No. 99-033 at 62; and *In the Matter of the Application of US West*, Docket UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses.[9]

Q. Please summarize Company's proposal for wages, salaries, incentives and overtime expense in this case.

A. The 2020 test year, on a Total Company basis, includes $35.9 million in wages and salaries (base pay), $2.5 million in incentive compensation, and $2.5 million in overtime.[10] The Oregon allocation factor is 25 percent with a 76/24 split for O&M and Capital.[11] In accordance with Commission policy, the Company removed all incentive compensation paid to the executive group as well as 50 percent of non-officer incentives based on non-financial metrics, lowering the revenue requirement by $686 thousand.[12] The Company states there are no officer incentives capitalized in plant costs.[13]

Q. How does the Company ascertain the appropriate compensation for employees?

A. The Company's philosophy is to set base pay using national general industry data and to provide base pay opportunities that are aligned with the market average for similar positions.[14] As part of this approach, nationally recognized salary survey data is used to benchmark jobs to determine which salary grade in the Company's salary structure that the job should be placed. Cascade uses

[9] See Order 99-697 at 44-45; Order 99-033 at 62.
[10] Staff/202, Cascade Response to Staff DR Nos. 92, 186.
[11] Staff/202, Cascade Response to Staff DR No. 93.
[12] CNGC/300, Peters/8; CNGC/301-306, Peters/304.
[13] Staff/202, Cascade Response to Staff DR No. 184.
[14] Staff/202, Cascade Response to Staff DR No. 98.

the median base salary in the survey and aligns to the closest mid-point in the Company's salary structure to determine the pay grade.[15]

Q. What adjustments did the Company make to its actual 2019 Base Year salaries and wages to forecast the 2020 Test Year?

A. The Company escalates the 2019 Base Year pay of non-union employees by four percent and the Base Year pay of union employees by three percent, adding $238 thousand to the Test Year expense.[16] The Company also annualizes the 2019 union contract rate increase, effective April 1, 2019, increasing the Test Year expense by $29 thousand.[17]

Q. What is Staff's recommendation?

A. As Company has removed executive incentives and 50 percent of non-executive incentives, Staff has no adjustments to incentives. Staff does have an adjustment to wages and salary and overtime expenses, however. Because Company is using a 2020 Test Year, Staff escalates Company's 2017 wages by 2.4, 1.8 and 0.7 percent for 2018, 2019 and 2020, respectively to apply the three-year W&S model.[18] The sharing principle, which allows the Company to share 50/50 the lesser of the difference between the Company's and Staff's calculated projections, or a 10 percent band around Staff's calculated projection, makes several reductions to Staff's projection. Staff's initial adjustment is reduced from $59 thousand to $30 thousand for Officer wages

[15] Staff/202, Cascade Response to Staff DR No. 99.
[16] Ibid.
[17] UG 390/CNGC/300, Peters/7, UG 390/CNGC/301-306 Peters Exhibits at 304.
[18] Staff/203: Oregon Economic & Revenue Forecast, Jun 2020, All Urban Consumer Price Index: https://www.oregon.gov/das/OEA/Documents/appendixa.pdf

while Staff's adjustment to Exempt wages falls from $7.7 million to $7.2 million.[19] Finally, the difference for Non-Exempt wages falls from $1.9 million to $1.8 million while Staff's adjustment for Union wages decreases from $1.4 million to $694 thousand.[20],[21] Staff used the negotiated union increases of three percent each year to escalate union wages.

In terms of overtime, a difference of $10 thousand between Staff's and Company's Test Year projection for Non-Exempt employees is reduced to $7 thousand after the sharing principle is applied.[22] There is no adjustment for Union overtime because the Company's forecast is less than Staff's projection. After using the Oregon allocation factor of 25 percent, Staff has the following adjustments to the Company's test year:

- Decrease salaries by $2.4 million (allocated $1.9 million O&M and $586 thousand Capital).[23]
- Decrease overtime by $1,660 (allocated $1,262 O&M and $400 Capital).[24]
- Small decreases for payroll taxes ($156 thousand) and Depreciation ($18 thousand).[25]

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[19] See Staff Electronic Workpaper UG 390 Exhibit 200 Issue 1 Wage & Salary Model CONF tab 3-yr W&S
[20] Ibid.
[21] Exempt and Nonexempt definitions: https://www.dol.gov/agencies/whd/flsa
[22] See Staff Electronic Workpaper UG 390 Exhibit 200 Issue 1 Wage & Salary Model CONF tab 3-yr OT
[23] See Staff Electronic Workpaper UG 390 Exhibit 200 Issue 1 Wage & Salary Model CONF tab 3-yr W&S
[24] See Staff Electronic Workpaper UG 390 Exhibit 200 Issue 1 Wage & Salary Model CONF tab 3-yr OT
[25] See Staff Electronic Workpaper UG 390 Exhibit 200 Issue 1 Wage & Salary Model CONF tab Misc. Labor

ISSUE 2. UNCOLLECTIBLE EXPENSE

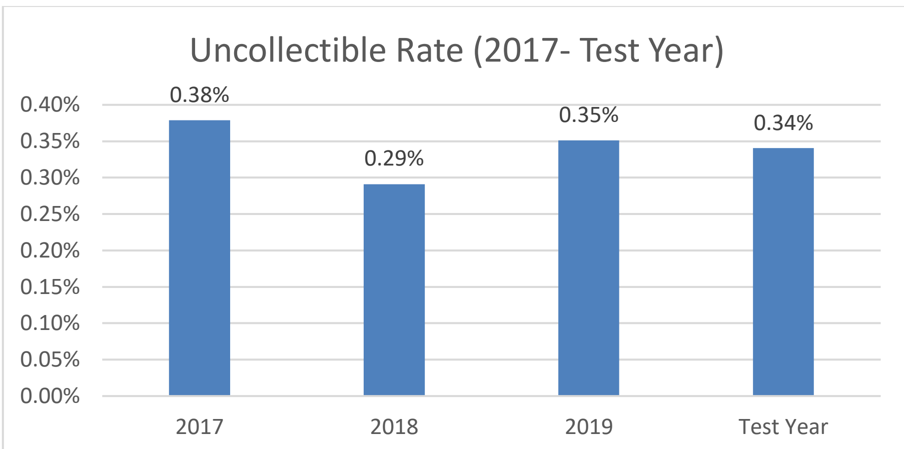
Q. Please provide a summary of the Commission's historical treatment of uncollectible expense.

The amount included in a utility's Revenue Requirement for uncollectible expense is revenue sensitive because it depends on the amount of forecasted revenue. The amount of uncollectible expense included in the Revenue Requirement is a function of the Test Year revenue and the uncollectible rate. The uncollectible rate is based on an average of the net-write offs, i.e., the uncollectible amounts that were written off the books, for the three years preceding Test Year divided by the average of the revenues for those same years. The uncollectible rate that is derived from this three-year average methodology is then multiplied by the forecast of Test Year revenue to determine the Test Year uncollectible expense for a utility's Revenue Requirement.[26] In addition, Commission Staff reviews other materials to determine the reasonableness of the rate and level of expense produced by the three-year model.

[26] *See, e.g.*, *In the Matter of Avista Corporation*, Docket UG 246, Order No. 14-015 at 3 (January 21, 2014); and *In the Matter of Avista Corporation*, Docket UG 186, Order No. 09-422, Appendix A at 4 (October 26, 2009) (adopting stipulations for Avista general rate increase with uncollectible expense in revenue requirement based on three-year average); *but see In the Matter of Idaho Power Company*, Docket UE 167, Order No. 05-871 (January 28, 2005) (adopting stipulation for Idaho Power Company general rate increase with uncollectible expense based on four-year average); and *In the Matter of Cascade Natural Gas Corporation*, Docket UG 287, Order No. 15-412 (December 28, 2015) (adopting stipulation for Cascade Natural Gas general rate increase with uncollectible expense based on three-year average, removing an anomalous year).

Q. Please provide a summary of the Company's filed proposal and Staff's analysis of the issue.

According to Company testimony, "Uncollectibles expense is an adjustment to test period booked uncollectibles expense to reflect an average of the last three years of actual net bad debt write-offs."[27] The Company's total adjustment of ($1,549) is the difference between the proforma uncollectible estimate (using 2019 sales and three-year average uncollectible rate) less the bad debt for the 2019 Base Year. As shown in Company's workpapers, Cascade utilizes calendar years 2017, 2018 and 2019 to calculate an uncollectible rate of 0.341 percent.[28]

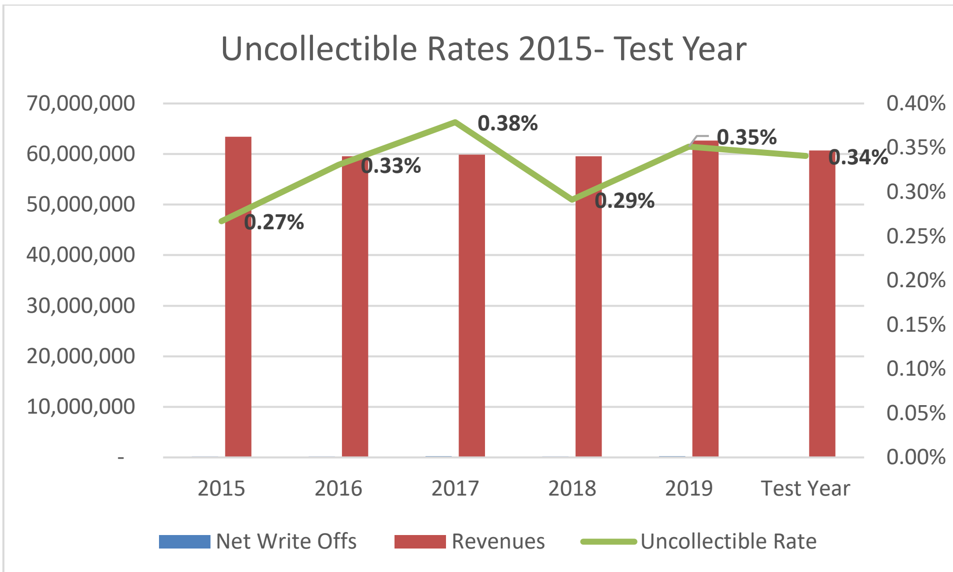


The effect on Oregon net operating income is an increase of $1,130, and decrease to Revenue Requirement of $1,601.[29]

[27] CNGC/300, Peters/6.
[28] See UG 390 Peters MCP-WP1, Uncollectibles tab.
[29] See UG 390 Peters MCP-WP1, Exh 304 Summary of Adjustments tab.

Q. Does Staff recommend any adjustment?

No. Staff agrees with the Company's calculation of the Base Year uncollectible expense and the revenue sensitive uncollectible rate. Staff also trended Company's historical uncollectible rate and finds its current rate reasonable.



ISSUE 3. ADVERTISING EXPENSES

Q. Does the Commission have a standard means of determining how advertising expenses are treated?

A. Yes, OAR 860-026-0022 specifies how advertising expenses are treated in a rate case. There are five categories (A-E) and each has a different standard for inclusion in rates. Category "A" includes energy efficiency or conservation advertising expenses that do not relate to a Commission-approved program, utility service advertising expenses, and utility information advertising expenses.[30] Advertising expenses in this category are presumed reasonable when expenses are twelve and one-half hundredths of one percent (0.125 percent) or less of the gross retail operating revenues determined in that proceeding.

Category "B" includes legally mandated advertising expenses assumed to be reasonable for rate-making purposes.[31] Category "C" includes institutional advertising expenses, promotional advertising expenses and any other advertising expenses not fitting into Category "A," "B," or "D".[32] Utilities must demonstrate these expenses are just and reasonable for inclusion in rates as well as separately state the amount of advertising expenses in this category. Category "D" includes political advertising expenses and nonutility advertising expenses deemed unreasonable.[33] Finally, Category "E" includes energy

[30] OAR 860-026-0022(2)(a).
[31] OAR 860-026-0022(2)(b).
[32] OAR 860-026-0022(2)(c).
[33] OAR 860-026-0022(2)(d).

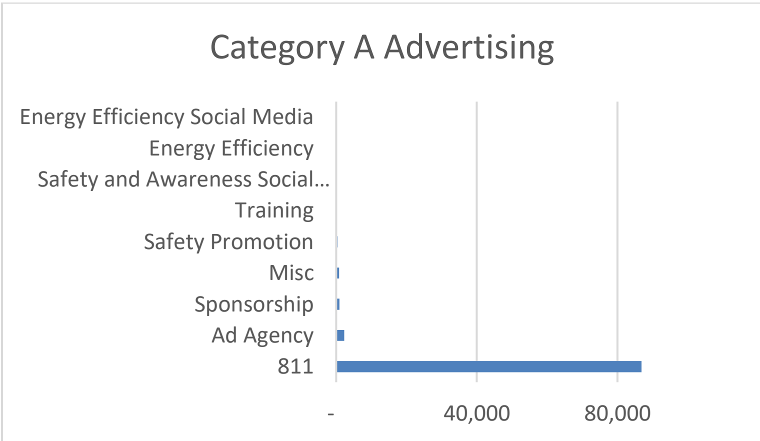
efficiency or conservation advertising expenses that relate to a Commission-approved program. With Commission approval, advertising expenses in Category "E" may be capitalized.[34]

Q. Please describe the Company's request for advertising.

A. The Company proposes to include approximately $100 thousand in its Test Year for advertising as illustrated below.[35]

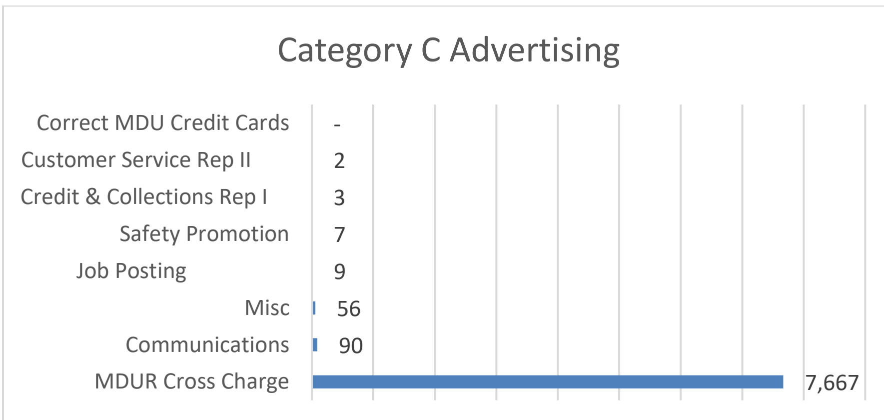
Category	Total
A	91,750
B	679
C	7,834
Grand Total	100,264

Cascade includes approximately $92 thousand in Category A, $679 in Category B expenses, and $7,834 in Category C. The Company does not have any advertising expenses in Categories D or E for its Test Year.[36]



[34] OAR 860-026-0022(2)(e).
[35] Staff/202, Company Response to SDR 104 A.
[36] Ibid.

Category A Advertising contains expenses related to 811 Safety advertising followed by ad agency purchases, sponsorship and miscellaneous expenses (costs related to Centurylink, phone listings, events and meetings).[37] The Category B expense of $679 relates to safety mailers by Minuteman Press of Kennewick.[38] The majority of the $7,834 of Category C Advertising expenses were for MDUR cross charges/reallocation expenses for ads, events and sponsorships.[39]



Q. Please describe your analysis of the Company's proposed advertising expenses.

Staff reviewed the Company's adjustment, which removed all promotional advertising expenses ($7,718).[40] Staff then analyzed expenditure breakdowns per Category and reviewed Company's transactional data both in Company's line item transaction descriptions and within the resulting

[37] See Staff electronic Workpaper UG 390 Issue 3 Advertising Expenses tab Cat A, Staff/202, Cascade Response to SDR 104 A.
[38] Staff/202, Company Response to SDR 104 A.
[39] See Staff electronic Workpaper UG 390 Issue 3 Advertising Expenses tab MDUR, Staff/202, Cascade Response to SDR 104 A.
[40] CNGC/300, Peters/7, See UG 390 Peters MCP-WP1, Exh 304 Summary of Adjustments tab.

media.[41] Most of these expenses went toward 811 advertisements, sponsorships, ads via Van Horn Media, and newspaper advertisements. Staff reviewed most of these ads and find that these expenses are reasonable.[42]

Q. How do the Company's advertising expenses compare to historical trends when categorized under the OAR 860-026-0022 categories mentioned above?

A. From 2017 to 2019, total expenses increased by 11 percent which included a nine percent rise in Category A, 27 percent increase in Category C and 100 percent decrease in Category D.[43]

Category	2017	2018	2019	2017-2019
A	83,810	52,000	91,750	9%
B	-	-	679	
C	6,192	6,861	7,834	27%
D	499			-100%
Total	90,501	58,861	100,264	11%

[41] Staff/202, Company Response to DR 57, Company Response to DRs 217-218.
[42] Ibid.
[43] Staff/202, Company Response to DR 145.

Q. What is your recommendation regarding advertising expense?

A. Company has exceeded the 0.125% limit of Category A Advertising by $7,912. Staff recommends an adjustment in this amount.[44]

Company's Response to DR 104	
Company's Operating Revenues	67,070,587
Category A Limit	0.125%
Amount Limit	83,838
Actual Spending	91,750
Difference	7,912

[44] Staff/202, Company Response to SDR 104 A.

ISSUE 4. CUSTOMER ACCOUNT AND CUSTOMER SERVICE EXPENSES

Q. Please describe customer accounting and customer service expenses.

A. Customer accounting expense is recorded in FERC accounts 901, 902, 903, 904, and 905. These accounts track expenses related to Supervision, Meter Reading, Customer Records and Collection, Uncollectibles, as well as Miscellaneous Customer Accounts. Customer Service expense consists of FERC accounts 907, 908, and 910 (excluding 909 Advertising, which was analyzed separately). These expenses are for Supervision, Customer Assistance, and Miscellaneous Customer Service. Uncollectibles, account 904, has been analyzed in a different section of this testimony.

Q. Does the Commission Staff have a standard for how Customer Account Expenses and Customer Service expenses are treated for ratemaking purposes?

A. Rule 860-026-0020 Standards Governing Promotional Activities and Concessions mandates that all promotional activities be just, reasonable, prudent, economically feasible and beneficial to both the utility and its customers. Staff reviews expenses per appropriate use per FERC account. Staff also reviews transaction-level data to ensure expenses relate to activities such as responding to customer requests, inquiries and safety concerns, resolving customer complaints, extending service to new customers, and providing information about safety and service issues.

Q. Please describe the Company's customer accounting and customer service expenses in the Base Year.

A. For Customer Account expenses (FERC accounts 901-905), the Company forecasted a Test Year Oregon allocated total of $1.9 million, which is the amount reported for 2019.[45] Customer Service expenses (FERC accounts 907-910) were also the same for Test Year and 2019 at $307 thousand.[46]

FERC	Description	Adjustments	Test Year	2019	2018	2017	2016
901-905	Customer Accounts Total	34,510	1,941,716	1,907,206	1,830,230	1,904,929	1,945,630
907-910	Customer Service Total	-	307,924	307,924	297,373	121,204	106,538
911-916, 930.1	Sales Expense Total	(7,718)	(5,644)	2,074	1,293	913	2,059
		26,792	2,243,995	2,217,203	2,128,896	2,027,047	2,054,226

Moreover, spending by labor category was also consistent from 2016 to Test Year, with labor-intensive spending in Customer Accounts and Customer Service, with the exception of Advertising, Miscellaneous expenses and Uncollectibles.[47]

		2019		2018		2017		2016	
FERC	Description	Labor	NonLabor	Labor	NonLabor	Labor	NonLabor	Labor	NonLabor
901	Supervision	98%	2%	94%	6%	89%	11%	0%	100%
902	Meter Reading	80%	20%	79%	21%	79%	21%	78%	22%
903	Cust Records	67%	33%	66%	34%	62%	38%	62%	38%
904	Uncollectibles	0%	100%	0%	100%	0%	100%	0%	100%
905	Misc Exp	0%	100%	0%	100%	0%	100%	0%	100%
907	Supervision								
908	Cust Assist	56%	44%	60%	40%	0%	100%	1%	99%
909	Info & Instr. Advertising	0%	100%	0%	100%	0%	100%	0%	100%
910	Misc. Cust Service	98%	2%	97%	3%	94%	6%		
911	Supervision								
912	Demonstrating & Selling	100%	0%						
913	Advertising	0%	100%	0%	100%	0%	100%	0%	100%
916	Misc Sales Exp.								
930.1	General Advertising Exp	0%	100%	0%	100%	0%	100%	0%	100%

[45] Staff/202 Company's Response to Staff DR 58 A Replacement.
[46] Ibid.
[47] Staff/202 Company's Response to Staff DR 58 A Replacement and 58 B Replacement.

To forecast its Test Year, Company made several adjustments to its Base Year, which impacted these accounts, as illustrated below.[48]

	Uncollectibles	Promotional Advertising	2020 Revenue Adj	Inflation Factor Adj	Total Adjustments
Customer Accounts	($1,549)		$1,729	34,330	$34,510
Customer Service					$0
Sales		($7,718)			($7,718)

The Company used a conversion factor to adjust the natural gas net operating income area deficiency for revenue sensitive items and taxes, resulting in an adjustment of ($1,549) in the Uncollectibles/Customer Accounts.[49] The Company removed all Base Year promotional advertising recorded in FERC accounts 913 and 930.1, totaling ($7,718).[50] The Company's revenue adjustment of $1,729 adds margin revenue to account for the additional customers at weather normalized loads to be added during 2020.[51] Finally, the Inflation Factor Adjustment shows the impact of escalating non-labor related expenses by the applying a consumer price index of 1.8 percent, resulting in an increase of $34,329 in Customer Accounts.[52] However, when Staff used the most current inflation factor of 0.7 percent for 2020, the results were approximately $21 thousand dollars less at $13,350.[53]

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[48] See UG 390 Peters MCP-WP1, Exh 304 Summary of Adjustments tab.
[49] CNGC/300, Peters/6, See UG 390 Peters MCP-WP1, Exh 304 Summary of Adjustments tab.
[50] CNGC/300, Peters/7, See UG 390 Peters MCP-WP1, Exh 304 Summary of Adjustments tab.
[51] Ibid.
[52] CNGC/300, Peters/8, See UG 390 Peters MCP-WP1, Exh 304 Summary of Adjustments tab.
[53] Staff/203: Oregon Economic & Revenue Forecast, Jun 2020, All Urban Consumer Price Index: https://www.oregon.gov/das/OEA/Documents/appendixa.pdf, See Staff Electronic Workpaper UG 390 Exhibit 200 Issue 4 Customer Accounts tab Staff Adjustment

Q. How does the amount requested in the Test Year differ from historical trends?

A. As previously mentioned, spending since 2016 has been fairly consistent, with some upticks in customer service expenses from 2018 on.[54] However, Staff noted a corresponding increase in customer count for those same years.[55] The only increase from Base Year to Test Year in these categories is attributed to Company's inflation adjustment of $34 thousand.

FERC	Description	Adjustments	Test Year	2019	2018	2017	2016
901-905	Customer Accounts Total	34,510	1,941,716	1,907,206	1,830,230	1,904,929	1,945,630
907-910	Customer Service Total	-	307,924	307,924	297,373	121,204	106,538
911-916, 930.1	Sales Expense Total	(7,718)	(5,644)	2,074	1,293	913	2,059
		26,792	2,243,995	2,217,203	2,128,896	2,027,047	2,054,226

Year End Customer Count				
Type	2016	2017	2018	2019
Residential	61,674	63,350	65,263	66,870
Commercial	10,081	10,196	10,310	10,399
Transportation	36	36	36	38
Total	71,791	73,582	75,609	77,307

Q. How did Staff perform its analysis of the Company's customer accounting and customer expense?

A. After reviewing historical trends and Company's adjustments, Staff reviewed Company's transactional data in its response to SDR 57 and submitted DRs 133-146 and 217-218 requesting copies of referenced materials.[56]

Q. Did Staff find any issue with customer accounting and customer service expense in the Company's application?

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[54] Staff/202 Company's Response to Staff DR 58 A Replacement.
[55] Staff/202 Company's Response to Staff DR 110.
[56] Staff/202 Company's Response to Staff DRs 133-146, 217-218.

A. Staff has a small reduction of $20,979 based on the update to the 2020 All Urban CPI.[57]

Q. Does this conclude your testimony?

A. Yes.

[57] See Staff Electronic Workpaper UG 390 Exhibit 200 Issue 4 Customer Accounts tab Staff Adjustment.

CASE: UG 390
WITNESS: HEATHER B. COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 201

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATION STATEMENT

NAME: Heather Cohen

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Utility Analyst
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE., Suite 100 Salem, OR. 97301

EDUCATION: Bachelor of Arts, Political Science
Fordham University, New York, NY

Master of Public Policy
American University, Washington, DC.

EXPERIENCE: I have been employed as a Senior Financial Analyst by the Oregon Public Utility Commission since January 2020 in the Energy, Rates and Finance Division. I currently perform a range of financial analysis duties related to natural gas and electric utilities, with a focus on operations and maintenance. I have worked on the following general rate dockets: UG 388, UG 389 (current) and UG 390 (current).

I have ten years of professional level budget and fiscal analysis experience. I was previously employed as a Budget Analyst with the Oregon Department of Education (ODE), where I was the lead analyst for the Early Learning Division (ELD) which includes the federal $97M Child Care Development Fund (CCDF) and $37M Preschool Promise program. Prior to ODE, I was a Senior Financial Analyst for the state of Texas's Department of Family and Protective Services and Health and Human Services. Before that, I was a Project Manager for the University of Southern California where I directed data collection and analysis, staffing and deliverables for a $1.2M federal grant related to the provision of mental health services in Los Angeles County. Prior to USC, I was a Senior Budget Analyst for the City of New York responsible for the $1B expense budget of the Administration for Children's Services (ACS).

CASE: UG 390
WITNESS: HEATHER B. COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 202

Exhibits in Support
Of Opening Testimony

July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 57

Date prepared: 3/27/2020

Preparer: Nellie Fellman

Contact: Chris Mickelson

Telephone: (509)-734-4549

57. Please provide transaction summaries for Non-Labor costs recorded in all FERC Accounts for the Base Year. Please place in MS Excel and for each transaction include:

    a) Account number and Account Description
    b) FERC Account and Account Description
    c) Total amount charged, and as applicable, any subtotals assigned to Non-Utility/Total Company Allocation and/or OR-Allocation. Please note that this response must include costs on an Oregon - Allocated Jurisdictional Share;
    d) Cost element
    e) Cost element description
    f) Description of cost that clearly demonstrates the business purpose;
    g) Name of vendor (if applicable);
    h) Business Unit (Profit Center) being charged;
    i) Service provided (e.g., reports to stockholders, lease, etc.).

Response:

See Attached: SDR-57a (Non-Labor costs).xlsx
Refer to SDR 78 & 79 for Account/FERC Descriptions.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 58

Date prepared: 3/11/2020

Preparer: Nellie Fellman

Contact: Chris Mickelson

Telephone: (509)-734-4549

58. Please provide a separate table in Excel for each subpart:

    a. For all FERC Accounts, please provide all of the information in the format as shown in Attachment 58 A or B[2]. If the requested information is not relevant to the Company's operations, please enter "N/A" in the appropriate cell. Please note that this response must include costs on an Oregon - Allocated Jurisdictional Share. Additional columns or other adaptations may be required if allocation occurs at multiple entities to arrive at the Oregon – Allocated Jurisdictional Share;

    b. Please provide the same information requested in a. above except EXCLUDE Labor Expense, from all entries.

Response:

See Attached SDR-58.xlsx

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 92

Date prepared: 3/31/20

Preparer: Kevin Conwell

Contact: Chris Mickelson

Telephone: (509) 734-4549

92. For the Test Year and the preceding 4 calendar years, please provide (on a Total Company basis and an Oregon –Allocated Jurisdictional Share), a summary table (using the categories and format shown below) that includes the number of FTE's (exclude FTE's created by overtime hours) and the actual paid cash compensation broken down between base wages or salaries, overtime, and incentives or bonuses. For any calendar year included in this request for which actual data is not available for the entire calendar year, please create a calendar year using the available actual data combined with the forecast applicable to the rest of the year. Please note which months and figures are associated with both the actual and forecast data. If the Oregon-Allocated Jurisdictional Share is unavailable then it will be estimated using the percentage provided in SDR No. 93 below.

Year: 2020 (Projected)*		Actual (Unadjusted) Paid Cash Compensation			
Category	❶ FTE	Base Wages	Overtime	Incentive/Bonus	Total
Officers	0	$997,653	$0	$662,215	$1,659,868
Exempt	107	$15,865,035	$0	$1,721,343	$17,586,378
Nonexempt	32	$3,660,085	$85,798	$129,563	$3,875,446
Union	192	$15,466,134	$2,420,522	$0	$17,886,656
Total	331	$35,988,909	$2,506,320	$2,513,121	$41,008,348
❶ Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

2020 Budgeted Capitalized labor is $8,921,324.65
*** All officers of the corporation are shared/allocated officers. CNG no longer has a 100% direct officer.**
**** Cascade direct only FTE's, does not include shared/allocated employees**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Year: 2019		Actual (Unadjusted) Paid Cash Compensation			
Category	❶ FTE**	Base Wages	Overtime	Incentive/Bonus	Total
Officers*		$951,011.00	$0	$1,166,153.48	$2,117,164.48
Exempt	107	$14,904,436.38	$0	$3,031,268.35	$17,935,704.73
Nonexempt	32	$3,437,297.64	$112,491.55	$228,159.98	$3,777,949.17
Union	192	$14,527,489.13	$3,173,606.36	$0	$17,701,095.49
Total	331	$33,820,234.15	$3,286,097.91	$4,425,581.82	$41,531,913.88
❶ Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

2019 Capitalized labor was $8,958,113.26
*** All officers of the corporation are shared/allocated officers. CNG no longer has a 100% direct officer.**
**** Cascade direct only FTE's, does not include shared/allocated employees**

Year: 2018		Actual (Unadjusted) Paid Cash Compensation			
Category	❶ FTE**	Base Wages	Overtime	Incentive/Bonus	Total
Officers*	0	$921,655.09	$0	$908,458.32	$1,830,113.41
Exempt	107	$14,625,567.19	$0	$1,758,471.77	$16,384,038.96
Nonexempt	36	$3,040,751.82	$115,240.16	$140,394.39	$3,296,386.37
Union	197	$14,243,072.03	$3,224,536.02	$0	$17,467,608.05
Total	340	$32,831,046.13	$3,339,776.18	$2,807,324.48	$38,978,146.79
❶ Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

2018 Capitalized labor was $8,101,885.55, which is included in the totals in the table above.
***All officers of the corporation are shared/allocated officers. CNG no longer has a 100% direct officer.**
**** Cascade direct only FTE's, does not include shared/allocated employees**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Year 2017		Actual (Unadjusted) Paid Cash Compensation			
Category	❶ FTE**	Base Wages	Overtime	Incentive/Bonus	Total
Officers*	1	$837,821.70	$0	$804,957.93	$1,642,779.63
Exempt	118	$8,621,819.96	$0	$2,157,181.02	$10,779,000.99
Nonexempt	37	$1,951,211.67	$83,033.76	$305,635.54	$2,339,880.97
Union	191	$12,817,061.43	$2,704,270.31	$0	$15,521,331.74
Total	347	$24,227,914.77	$2,787,304.07	$3,267,774.49	$30,282,993.33
❶ Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

2017 Capitalized labor was $8,647,332.00
***Cascade direct officer only does not include shared/allocated officers**
**** Cascade direct only FTE's, does not include shared/allocated employees**

Year: 2016		Actual (Unadjusted) Paid Cash Compensation			
Category	❶ FTE**	Base Wages	Overtime	Incentive/Bonus	Total
Officers*	1	$775,398.32	$0	$464,465.71	$1,239,864.03
Exempt	108	$8,360,466.75	$0	$1,553,382.43	$9,913,849.18
Nonexempt	37	$1,807,341.72	$58,513.64	$366,269.61	$2,232,124.97
Union	193	$12,514,873.67	$2,413,284.39	$0	$14,928,158.06
Total	339	$23,458,080.46	$2,471,798.03	$2,384,117.75	$28,313,996.24
❶ Please Exclude Full-Time Equivalent (FTE) Created by Overtime					

2016 Capitalized labor was $8,534,933.14
***Cascade direct officer only does not include shared/allocated officers**
**** Cascade direct only FTE's, does not include shared/allocated employees**

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Response:

Please use the % from SDR #93 to calculate/estimate the Oregon direct/allocated share of the amounts included in the tables above.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 93

Date prepared: 2/27/2020

Preparer: Nellie Fellman

Contact: Chris Mickelson

Telephone: (509)-734-4549

93. For the Test Year, please provide the breakout between O&M and rate base for all labor expense expressed as percentages. If applicable, please also provide the breakout for all labor expense between Total Company and Oregon – Allocated Jurisdictional Share expressed as a percentage.

Response:

See Attached: SDR-93.xlsx

Total Company:
O&M – 76%
Rate Base – 24%

Oregon
25%

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 98

Date prepared: 2/24/2020

Preparer: Justin Waldron

Contact: Chris Mickelson

Telephone: (509)-734-4549

98. Please provide any salary studies performed by the Company that pertain to the Test Year or any of the four preceding years. Please show the results of the salary study and narrative explanations for how the Company uses the salary study information. Please provide Company policy information for how the salary studies have been applied in past years and how they have impacted the Company's decision to increase or decrease wages or incentives as a result of the study.

Response:

Cascade Natural Gas Corporation's philosophy is to set base pay using national general industry data and to provide base pay opportunities that are aligned with the market average for similar positions. Periodically the Company contracts with an outside independent consultant to review compensation programs and practices. In 2018, the Company contracted with Pearl Meyer to provide a third-party review of base compensation and incentive compensation (Study Attached).

The review indicated that Cascade in general has a detailed, thoughtful set of policies and methodologies covering all aspects of its compensation program. Recommendations for improvement were primarily minor enhancements to employee pay opportunities because of Cascade's conservative approach to total compensation. For example, Pearl Meyer suggested that in order to keep the Company competitive with peers, more weight should be placed on industry-specific market rather than general industry.

In addition to periodic third-party reviews, Human Resources reviews standard benchmark jobs in the corporation annually, including job families such as engineers, construction supervisors and system analysts. The Company's total compensation package for the benchmark jobs are compared to market compensation for comparable positions to ensure that the Company is compensating employees at the appropriate pay grade and range.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Human Resources also reviews positions on an “as needed” basis throughout the year to ensure it is competitively compensating within the established pay ranges. The Company uses many reputable industry surveys when determining base pay levels, including the American Gas Association, Salary.com data, Mercer Benchmark, Towers Watson and World at Work, among others.

Human Resources reviews standard benchmark data regarding salary structures as well as salary increase budgets to determine any changes to the compensation structure. The Company uses many reputable industry surveys when determining both compensation structure and salary increase budgets, including the American Gas Association, Salary.com data, Mercer Benchmark, Towers Watson and World at Work, among others.

The salary surveys used are proprietary to the companies in which they are purchased from. Cascade’s salary data used in the matching to those surveys is “highly confidential”. Because Cascade Natural Gas Corporation does not have permission to share the survey information it can be made available onsite for review if needed.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 99

Date prepared: February 6, 2020

Preparer: Justin Waldron

Contact: Chris Mickelson

Telephone: (509)-734-4549

99. Please demonstrate whether the wages and salaries in the Test Year or the preceding four calendar years are above or below market compensation. Please provide the information relied upon to demonstrate the Company's assertion of whether wages and salaries are above or below market levels.

Response:

As described in the response for Request No. 98, Cascade Natural Gas Corporation uses an approach to compensation that is commonly accepted in the industry. As part of the approach nationally recognized salary survey data is used to benchmark jobs to determine which salary grade in the Company's salary structure that the job should be placed. Cascade uses the median base salary in the survey and aligns to the closest mid-point in the Cascade's salary structure to determine the pay grade. A pay compa-ratio of "1" indicates "market level" using this approach. A compa-ratio over "1" indicates pay is above market and below "1" indicates pay is below market.

As a test to illustrate how Cascade's employee pay compares to market levels, the compa-ratio is used and an average for each year is provided. Due to system reporting limitations, the annual year-end salary review is used for years 2016 – 2019. The year-end time is used because it captures points in time where the majority of non-union employee's salaries are reviewed and adjusted. 2020 data is reported using the period ending data of the most recent payroll at time of this response. Salaries and pay rates are not provided to maintain confidentiality of employee pay.

Here is a summary of average compa-ratio by year. Details by individual (excluding names and salary) are provided in spreadsheet form.

Date	Avg Compa-Ratio
1/19/2020	.96
12/09/2019	.96
12/10/2018	.97

Date	Avg Compa-Ratio
12/14/2017	.98
12/15/2016	.99

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

Request No. 104

Date prepared: 02/25/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

104. For the questions below related to advertising expense, please see the definitions and descriptions in OAR 860-026-0022. For questions related to promotional activities or concessions, please see OAR 860-026-0015 & 0020. Additionally, please provide the expense included in the Test Year on an Oregon – Allocated Jurisdictional Share. If the Total Company amounts were used in the calculations, please provide.

a. Please identify the Category A advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;
b. Please provide a work paper that shows the calculation of the Category A limit provided in OAR 860-026-0022 (3) (a);
c. If the Test Year Category A advertising expense exceeds the OAR 860 026-0022 (3) (a) limit, please provide support for including the additional expense in rates;
d. Please identify the Category B advertising expense included in the Test Year; including references to the appropriate testimony and / or exhibit pages;
e. For any Category C advertising expense included in the Test Year revenue requirement that is associated with a promotional activity or a promotional concession program, please provide a summary table that includes:
i. A description of the activity or program, and justification for inclusion into rates;
ii. A breakout of the related expense by labor & non-labor; and
iii. The FERC and internal utility account to which the expense will be booked and include references to appropriate exhibit pages.
f. Please identify any other budgeted advertising expense for the test year that will NOT be included in base rates, including below-the-line or nonutility expense, or advertising expense expected to be collected through a tariff. Please include how the expense is allocated between the categories identified in OAR 860-026-0022(2). Please describe the activities and associated expense (broken out by labor & non- labor) associated with marketing research and sales activities (include fuel switching and retention of customers) that is included in the test year. Please include references to the testimony and exhibits, and to which FERC and internal utility accounts this expense is booked.

Response:

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
Standard Data Requests

See attached spreadsheet SDR-104.xlsx

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 145

Date prepared: 4/27/20

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

145. Please provide total actual and budgeted expenditures for each category of advertising (Category A, B, C, D, and E) from 2017 through 2020. Please include data on the Oregon-allocated amount of each total. Please provide the data in electronic, Excel format with all formulae and cell references intact.

Response:

See attached Excel Spreadsheet OPUC-145.xlsx. Data for 2020 is only for actuals through March 31, 2020.

CNGC does not budget expenditures by the categories above or on an allocated basis.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 184

Date prepared: 5/14/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

184. Please provide the amount of Officer Incentives and Other Executives incentives (Officers) capitalized in Plant Costs.

Officers' Incentives Capitalized in Plant			
Calendar Year	Cascade	Allocated to Oregon Jurisdiction	Allocated to Oregon Jurisdiction and included in rate base
2016	$	$	$
2017			
2018			
2019			
2020			
Total			

Response:

None are capitalized in Plant Costs.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 186

Date prepared: 5/21/2019

Preparer: Kevin Conwell

Contact: Chris Mickelson

Telephone: (509)-734-4549

186. In regards to Company's response to SDR 92, please provide a number or percentage of FTE for Officers. There is corresponding salary and incentives for Officers therefore an FTE of zero cannot be correct. Staff will assume Officers are 25% of an FTE if no amount is provided by the Company.

Response:

2020 (Projected) – 3.83
2019 – 3.83
2018 – 3.88
2017 – 3.59
2016 – 3.03

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 217

Date prepared: 06/17/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

For purposes of this request, the term "copy" means:

a. For printed advertising, a hard copy or pdf of the material;
b. For a radio broadcast, a hard copy or pdf of the radio script;
c. For a television broadcast, a link to a video of the advertisement on a webpage accessible by Staff, a DVD, or in a file format viewable on a modern Windows operating system;
d. For an online advertisement, an Adobe PDF of any webpages created; and
e. For other items not listed above, including but not limited to billboards, banners, displays, hats, mugs, and pens, – a hard copy picture or digital picture that provides an accurate depiction of the item.

217. In reference to Company's response to DR 57 A, please provide a copy of the advertising media produced for each of the line items below:

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

FERC	Desc	Amount	Oregon Situs	Oregon Alloc 24.83%	OR Total	Explanation 1	Explanation 2
903	Customer Records & Col	144		36	36	SHEPARD PRINTING CORP	NEWSLETTERS W/MERCAPTAN SCENT
909	Inform. & Instr. Adv	63,000		15,643	15,643	COR OPS DEPT EXPENSES 0219	VAN HORN MEDIA
909	Inform. & Instr. Adv	2,776	2,776		2,776	COR OPS DEPT EXPENSES 0219	EAST OREGONIAN
908	Customer Assistance Ex	7,689		1,909	1,909	CORPORATE PROMOTIONS LTD	Nitrile Gloves
908	Customer Assistance Ex	200	200		200	MALHEUR COUNTY FAIR BOARD	Banner Sponsorship
908	Customer Assistance Ex	50	50		50	K MCCAULEY 3-19	Prize Giveaway - Gift Card
909	Inform. & Instr. Adv	1,320	1,320		1,320	L DEMKO-EDWARDS 3-19	Bend-Newspaper-811
908	Customer Assistance Ex	1,500	1,500		1,500	JEFFERSON COUNTY FAIRY COMPLEX	SPONSORSHIP
908	Customer Assistance Ex	650	650		650	LA PINE RODEO ASSOCATION	SPONSORSHIP
908	Customer Assistance Ex	313.89	313.89		313.89	K MCCAULEY 5-19	811 Stickers
909	Inform. & Instr. Adv	1,320		328	328	L DEMKO-EDWARDS 5-19	811Ad-MtVernon-Newspaper
909	Inform. & Instr. Adv	5,800		1,440	1,440	KITSAP SUN	811 ONLINE BANNER ADVERTISING
909	Inform. & Instr. Adv	15,000		3,725	3,725	KITSAP SUN	AUG-NOV 2019
909	Inform. & Instr. Adv	14,000		3,476	3,476	KITSAP SUN	AUG-NOV 2019
908	Customer Assistance Ex	500.00		124.15	124.15	Building Industry Assn. of Wha	CATF PROMOTIONAL
909	Inform. & Instr. Adv	17,257		4,285	4,285	MINUTEMAN PRESS OF KENNEWICK	coloring books

Response:

See attached OPUC-217.pdf

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 218

Date prepared: 6/22/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

218. If any line item identified in the prior requests did not directly result in the creation of a piece of advertising media, please:
   a. Identify the line item;
   b. Provide a narrative description including the purpose of the expense; and
   c. Provide supporting documentation for the expense.

Response:

a) Line 6

b) $50.00 dollar gift card for prize giveaway during Contractor 811 meeting.

c) see page 7 of pdf response to DR-217

CASE: UG 390
WITNESS: HEATHER B. COHEN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 203

Exhibits in Support
Of Opening Testimony

July 30, 2020

APPENDIX A: ECONOMIC FORECAST DETAIL

Table A.1 – Employment Forecast Tracking

Total Nonfarm Employment, 1st quarter 2020

(Employment in thousands, Annualized Percent Change)

	Preliminary Estimate		Forecast		Forecast Error		Y/Y Change
	level	% ch	level	% ch	level	%	% ch
Total Nonfarm	1,960.1	0.6	1,959.7	1.9	0.4	0.0	1.4
Total Private	1,657.6	(0.1)	1,660.3	1.9	(2.7)	(0.2)	1.3
Mining and Logging	6.7	(6.9)	7.0	12.0	(0.3)	(3.8)	(4.4)
Construction	112.5	5.2	110.2	1.6	2.3	2.1	3.8
Manufacturing	196.4	(1.8)	198.7	0.7	(2.3)	(1.2)	(1.2)
Durable Goods	135.7	(1.2)	138.0	2.6	(2.3)	(1.7)	(1.6)
Wood Product	22.7	(4.0)	23.6	5.8	(0.9)	(3.9)	(3.8)
Metals and Machinery	39.9	(2.5)	40.2	0.9	(0.4)	(1.0)	(1.5)
Computer and Electronic Product	38.6	0.7	39.0	4.2	(0.4)	(0.9)	(0.0)
Transportation Equipment	12.2	(2.6)	12.4	(6.2)	(0.2)	(1.7)	(3.2)
Other Durable Goods	22.3	1.4	22.8	4.9	(0.4)	(2.0)	(1.3)
Nondurable Goods	60.7	(3.2)	60.7	(3.5)	(0.0)	(0.0)	(0.2)
Food	28.9	(8.5)	29.1	(7.3)	(0.2)	(0.7)	(4.1)
Other Nondurable Goods	31.8	1.9	31.6	0.2	0.2	0.6	3.6
Trade, Transportation & Utilities	360.3	0.8	359.1	0.4	1.2	0.3	1.3
Retail Trade	208.6	(0.5)	209.7	0.2	(1.1)	(0.5)	(0.9)
Wholesale Trade	77.0	1.5	77.0	1.3	0.0	0.0	0.7
Transportation, Warehousing & Utilities	74.7	3.5	72.4	0.1	2.3	3.2	8.5
Information	35.2	(5.8)	35.5	2.0	(0.3)	(0.8)	1.8
Financial Activities	104.9	2.7	104.1	1.5	0.8	0.7	1.9
Professional & Business Services	257.2	(1.3)	257.2	3.1	(0.1)	(0.0)	1.9
Educational & Health Services	304.3	(1.3)	306.2	2.9	(1.9)	(0.6)	2.1
Educational Services	36.5	(5.3)	36.3	(7.2)	0.3	0.7	(0.1)
Health Services	267.8	(0.8)	269.9	4.3	(2.2)	(0.8)	2.4
Leisure and Hospitality	214.8	(0.1)	217.8	3.4	(3.0)	(1.4)	0.7
Other Services	65.3	2.2	64.4	(0.9)	0.9	1.4	0.9
Government	302.5	4.2	299.4	2.0	3.1	1.0	1.6
Federal	28.5	1.2	27.9	(6.3)	0.6	2.1	0.9
State	42.2	23.6	39.6	(2.4)	2.6	6.6	2.7
State Education	0.9	(12.7)	0.8	(7.3)	0.1	11.9	13.6
Local	231.7	1.4	231.8	3.9	(0.1)	(0.1)	1.5
Local Education	135.8	1.6	132.3	(2.2)	3.5	2.7	2.3

Table A.2 – Short-Term Oregon Economic Summary

Oregon Forecast Summary

	Quarterly					Annual					
	2020:1	2020:2	2020:3	2020:4	2021:1	2019	2020	2021	2022	2023	2024
Personal Income ($ billions)											
Nominal Personal Income	229.4	224.4	226.2	222.4	222.9	223.3	225.6	226.0	236.6	249.2	262.8
% change	6.2	(8.5)	3.3	(6.6)	0.9	4.8	1.0	0.2	4.7	5.3	5.4
Real Personal Income (base year=2012)	207.2	203.9	204.6	200.2	199.9	203.6	204.0	201.4	206.8	213.0	219.9
% change	4.6	(6.3)	1.4	(8.3)	(0.7)	3.3	0.2	(1.3)	2.6	3.0	3.2
Nominal Wages and Salaries	115.8	96.6	99.6	102.2	103.3	112.0	103.6	104.6	112.3	122.5	132.5
% change	9.9	(51.6)	12.9	10.9	4.3	4.6	(7.5)	1.1	7.3	9.1	8.2
Other Indicators											
Per Capita Income ($1,000)	53.9	52.6	53.0	52.0	52.1	52.7	52.9	52.7	54.7	57.2	59.8
% change	5.6	(9.1)	2.7	(7.2)	0.5	3.8	0.4	(0.4)	3.9	4.4	4.6
Average Wage rate ($1,000)	58.3	61.5	59.7	59.3	59.4	57.1	59.7	59.6	61.4	64.0	66.8
% change	7.4	23.9	(11.2)	(2.9)	0.7	3.0	4.5	(0.1)	3.0	4.2	4.4
Population (Millions)	4.3	4.3	4.3	4.3	4.3	4.24	4.27	4.29	4.32	4.36	4.40
% change	0.6	0.7	0.6	0.6	0.4	1.0	0.7	0.6	0.8	0.8	0.8
Housing Starts (Thousands)	18.9	15.3	14.9	15.7	16.2	20.7	16.2	16.7	18.9	21.4	21.9
% change	(30.2)	(57.1)	(10.3)	21.6	13.3	5.9	(21.7)	3.0	13.3	13.1	2.3
Unemployment Rate	3.9	22.7	18.5	16.0	15.3	4.1	15.3	14.7	11.4	7.6	4.6
Point Change	0.0	18.8	(4.2)	(2.5)	(0.7)	(0.0)	11.2	(0.6)	(3.3)	(3.8)	(3.0)
Employment (Thousands)											
Total Nonfarm	1,960.1	1,553.6	1,650.5	1,707.1	1,722.4	1,942.9	1,717.8	1,736.9	1,810.7	1,898.1	1,969.2
% change	0.6	(60.5)	27.4	14.4	3.6	1.6	(11.6)	1.1	4.2	4.8	3.7
Private Nonfarm	1,657.6	1,250.2	1,350.2	1,410.4	1,427.8	1,644.0	1,417.1	1,444.0	1,514.9	1,600.0	1,666.4
% change	(0.1)	(67.6)	36.0	19.1	5.0	1.6	(13.8)	1.9	4.9	5.6	4.1
Construction	112.5	86.6	85.5	86.1	88.6	109.4	92.7	91.5	96.4	100.9	104.4
% change	5.2	(64.9)	(5.1)	3.1	11.9	3.7	(15.3)	(1.3)	5.4	4.6	3.5
Manufacturing	196.4	161.1	157.4	153.4	153.2	198.0	167.1	157.2	168.9	178.1	183.3
% change	(1.8)	(54.7)	(8.9)	(9.8)	(0.6)	1.4	(15.6)	(5.9)	7.4	5.5	2.9
Durable Manufacturing	135.7	109.2	106.2	103.0	102.5	137.0	113.5	106.0	115.2	121.9	125.9
% change	(1.2)	(58.0)	(10.7)	(11.5)	(1.7)	1.1	(17.1)	(6.6)	8.7	5.8	3.2
Wood Product Manufacturing	22.7	15.3	15.2	14.6	14.7	23.2	17.0	15.0	17.3	20.0	21.8
% change	(4.0)	(79.0)	(4.7)	(12.8)	0.8	(1.2)	(27.0)	(11.2)	15.2	15.3	8.9
High Tech Manufacturing	38.6	37.0	37.0	36.9	36.3	38.6	37.4	36.8	37.4	37.5	37.4
% change	0.7	(15.7)	(0.2)	(1.2)	(6.0)	1.8	(3.2)	(1.5)	1.6	0.2	(0.3)
Transportation Equipment	12.2	9.8	9.5	9.2	9.3	12.6	10.2	9.6	10.3	10.8	11.3
% change	(2.6)	(58.2)	(11.5)	(11.6)	0.8	3.6	(18.9)	(6.0)	7.4	4.5	5.1
Nondurable Manufacturing	60.7	51.9	51.3	50.4	50.6	61.0	53.6	51.2	53.7	56.2	57.4
% change	(3.2)	(46.4)	(5.1)	(6.2)	1.5	2.2	(12.2)	(4.4)	4.7	4.7	2.2
Private nonmanufacturing	1,461.3	1,089.1	1,192.8	1,257.0	1,274.6	1,446.1	1,250.0	1,286.8	1,346.0	1,421.9	1,483.1
% change	0.2	(69.1)	43.9	23.3	5.7	1.6	(13.6)	2.9	4.6	5.6	4.3
Retail Trade	208.6	158.0	174.1	183.9	184.5	209.8	181.2	185.2	188.3	191.5	195.2
% change	(0.5)	(67.1)	47.5	24.7	1.2	(0.8)	(13.6)	2.3	1.6	1.7	2.0
Wholesale Trade	77.0	66.0	63.0	65.5	66.8	76.5	67.9	67.2	69.3	72.7	76.3
% change	1.5	(45.9)	(17.0)	16.7	8.3	1.2	(11.3)	(1.0)	3.1	4.9	5.0
Information	35.2	31.0	30.7	31.2	31.8	35.1	32.0	32.1	32.9	33.2	33.4
% change	(5.8)	(39.8)	(3.8)	7.0	7.8	2.1	(8.6)	0.2	2.3	0.9	0.8
Professional and Business Services	257.2	222.3	216.5	220.3	223.3	254.3	229.1	225.3	240.7	266.2	287.1
% change	(1.3)	(44.2)	(10.1)	7.2	5.6	1.8	(9.9)	(1.6)	6.8	10.6	7.9
Health Services	267.8	201.9	232.5	247.5	250.8	264.9	237.4	253.7	263.4	273.8	285.1
% change	(0.8)	(67.7)	75.8	28.4	5.4	2.3	(10.4)	6.9	3.8	3.9	4.1
Leisure and Hospitality	214.8	86.7	139.0	160.8	164.9	213.8	150.3	166.9	184.9	207.6	222.7
% change	(0.1)	(97.3)	560.4	79.0	10.7	1.1	(29.7)	11.0	10.8	12.3	7.3
Government	302.5	303.4	300.3	296.6	294.6	298.9	300.7	292.9	295.9	298.1	302.8
% change	4.2	1.2	(4.0)	(4.8)	(2.7)	1.4	0.6	(2.6)	1.0	0.8	1.6

Table A.3 – Oregon Economic Forecast Change

Oregon Forecast Change (Current vs. Last)

	Quarterly					Annual					
	2020:1	**2020:2**	**2020:3**	**2020:4**	**2021:1**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**
Personal Income ($ billions)											
Nominal Personal Income	229.4	224.4	226.2	222.4	222.9	223.3	225.6	226.0	236.6	249.2	262.8
% change	(0.2)	(3.5)	(3.9)	(6.6)	(7.5)	(0.2)	(3.6)	(7.9)	(8.1)	(7.7)	(7.2)
Real Personal Income (base year=2012)	207.2	203.9	204.6	200.2	199.9	203.6	204.0	201.4	206.8	213.0	219.9
% change	(0.1)	(2.4)	(2.9)	(5.7)	(6.7)	(0.2)	(2.8)	(6.9)	(6.9)	(6.4)	(5.9)
Nominal Wages and Salaries	115.8	96.6	99.6	102.2	103.3	112.0	103.6	104.6	112.3	122.5	132.5
% change	(0.4)	(18.1)	(16.7)	(15.6)	(15.8)	(0.4)	(12.8)	(16.4)	(14.8)	(11.4)	(8.7)
Other Indicators											
Per Capita Income ($1,000)	53.9	52.6	53.0	52.0	52.1	52.7	52.9	52.7	54.7	57.2	59.8
% change	(0.1)	(3.3)	(3.6)	(6.2)	(7.1)	(0.2)	(3.3)	(7.4)	(7.5)	(6.9)	(6.4)
Average Wage rate ($1,000)	58.3	61.5	59.7	59.3	59.4	57.1	59.7	59.6	61.4	64.0	66.8
% change	(0.8)	3.6	(0.4)	(2.1)	(2.9)	(0.4)	0.0	(3.9)	(5.1)	(5.1)	(5.0)
Population (Millions)	4.26	4.26	4.27	4.3	4.3	4.24	4.27	4.29	4.32	4.36	4.40
% change	(0.2)	(0.2)	(0.3)	(0.4)	(0.5)	0.0	(0.3)	(0.6)	(0.7)	(0.8)	(0.8)
Housing Starts (Thousands)	18.9	15.3	14.9	15.7	16.2	20.7	16.2	16.7	18.9	21.4	21.9
% change	(14.1)	(31.5)	(34.0)	(31.2)	(30.5)	(0.1)	(27.8)	(28.4)	(19.9)	(8.5)	(7.5)
Unemployment Rate	3.9	22.7	18.5	16.0	15.3	4.1	15.3	14.7	11.4	7.6	4.6
Point Change	0.0	18.9	14.7	12.2	11.5	0.0	11.4	10.8	7.4	3.4	0.2
Employment (Thousands)											
Total Nonfarm	1,960.1	1,553.6	1,650.5	1,707.1	1,722.4	1,942.9	1,717.8	1,736.9	1,810.7	1,898.1	1,969.2
% change	0.0	(21.2)	(16.5)	(13.9)	(13.5)	0.1	(12.9)	(13.1)	(10.4)	(6.8)	(3.9)
Private Nonfarm	1,657.6	1,250.2	1,350.2	1,410.4	1,427.8	1,644.0	1,417.1	1,444.0	1,514.9	1,600.0	1,666.4
% change	(0.2)	(25.0)	(19.4)	(16.1)	(15.4)	0.1	(15.2)	(14.8)	(11.5)	(7.3)	(4.0)
Construction	112.5	86.6	85.5	86.1	88.6	109.4	92.7	91.5	96.4	100.9	104.4
% change	2.1	(21.7)	(22.8)	(22.4)	(20.6)	0.3	(16.2)	(18.4)	(14.2)	(10.9)	(8.3)
Manufacturing	196.4	161.1	157.4	153.4	153.2	198.0	167.1	157.2	168.9	178.1	183.3
% change	(1.2)	(18.9)	(20.7)	(22.6)	(22.7)	(0.1)	(15.9)	(20.5)	(14.6)	(9.9)	(7.3)
Durable Manufacturing	135.7	109.2	106.2	103.0	102.5	137.0	113.5	106.0	115.2	121.9	125.9
% change	(1.7)	(20.9)	(23.0)	(25.2)	(25.5)	(0.2)	(17.7)	(22.6)	(15.6)	(10.5)	(7.6)
Wood Product Manufacturing	22.7	15.3	15.2	14.6	14.7	23.2	17.0	15.0	17.3	20.0	21.8
% change	(3.9)	(35.1)	(35.6)	(37.6)	(37.6)	(0.3)	(28.0)	(35.5)	(25.3)	(14.2)	(7.9)
High Tech Manufacturing	38.6	37.0	37.0	36.9	36.3	38.6	37.4	36.8	37.4	37.5	37.4
% change	(0.9)	(5.1)	(4.8)	(5.2)	(6.4)	0.0	(4.0)	(4.9)	(3.8)	(3.4)	(2.9)
Transportation Equipment	12.2	9.8	9.5	9.2	9.3	12.6	10.2	9.6	10.3	10.8	11.3
% change	(1.7)	(21.4)	(24.1)	(26.7)	(26.6)	(0.5)	(18.5)	(23.8)	(18.1)	(14.5)	(10.5)
Nondurable Manufacturing	60.7	51.9	51.3	50.4	50.6	61.0	53.6	51.2	53.7	56.2	57.4
% change	(0.0)	(14.4)	(15.4)	(16.8)	(16.6)	(0.1)	(11.7)	(15.8)	(12.4)	(8.8)	(6.8)
Private nonmanufacturing	1,461.3	1,089.1	1,192.8	1,257.0	1,274.6	1,446.1	1,250.0	1,286.8	1,346.0	1,421.9	1,483.1
% change	(0.0)	(25.8)	(19.2)	(15.2)	(14.4)	0.1	(15.1)	(14.0)	(11.1)	(6.9)	(3.6)
Retail Trade	208.6	158.0	174.1	183.9	184.5	209.8	181.2	185.2	188.3	191.5	195.2
% change	(0.5)	(24.7)	(17.1)	(12.4)	(12.1)	(0.1)	(13.7)	(11.8)	(10.5)	(9.1)	(7.5)
Wholesale Trade	77.0	66.0	63.0	65.5	66.8	76.5	67.9	67.2	69.3	72.7	76.3
% change	0.0	(14.3)	(18.4)	(15.3)	(13.7)	0.2	(12.0)	(13.3)	(10.9)	(6.6)	(2.0)
Information	35.2	31.0	30.7	31.2	31.8	35.1	32.0	32.1	32.9	33.2	33.4
% change	(0.8)	(12.4)	(13.1)	(11.7)	(10.0)	0.4	(9.5)	(9.2)	(7.1)	(6.2)	(5.3)
Professional and Business Services	257.2	222.3	216.5	220.3	223.3	254.3	229.1	225.3	240.7	266.2	287.1
% change	(0.0)	(14.2)	(17.8)	(17.3)	(17.3)	0.2	(12.4)	(17.9)	(15.4)	(7.9)	(2.2)
Health Services	267.8	201.9	232.5	247.5	250.8	264.9	237.4	253.7	263.4	273.8	285.1
% change	(0.8)	(25.9)	(15.1)	(10.0)	(9.2)	0.1	(13.0)	(8.7)	(6.8)	(4.8)	(2.2)
Leisure and Hospitality	214.8	86.7	139.0	160.8	164.9	213.8	150.3	166.9	184.9	207.6	222.7
% change	(1.4)	(60.4)	(37.0)	(27.6)	(25.9)	(0.1)	(31.6)	(25.2)	(17.6)	(8.5)	(2.4)
Government	302.5	303.4	300.3	296.6	294.6	298.9	300.7	292.9	295.9	298.1	302.8
% change	1.0	(0.1)	(0.6)	(1.9)	(2.9)	0.2	(0.4)	(3.9)	(3.9)	(4.0)	(3.3)

Table A.4 – Annual Economic Forecast

Jun 2020 - Personal Income

(Billions of Current Dollars)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Personal Income*												
Oregon	213.1	223.3	225.6	226.0	236.6	249.2	262.8	277.0	291.4	306.3	322.0	338.5
% Ch	6.2	4.8	1.0	0.2	4.7	5.3	5.4	5.4	5.2	5.1	5.1	5.1
U.S.	17,819.2	18,602.3	18,913.4	19,494.0	20,405.7	21,176.3	21,991.6	22,972.5	24,043.2	25,176.9	26,395.3	27,676.2
% Ch	5.6	4.4	1.7	3.1	4.7	3.8	3.9	4.5	4.7	4.7	4.8	4.9
Wage and Salary												
Oregon	107.0	112.0	103.6	104.6	112.3	122.5	132.5	140.6	148.3	156.2	164.3	172.6
% Ch	5.7	4.6	(7.5)	1.1	7.3	9.1	8.2	6.1	5.5	5.3	5.2	5.1
U.S.	8,888.5	9,297.8	8,996.6	9,321.1	10,188.8	10,718.5	11,121.1	11,576.5	12,097.6	12,654.1	13,245.4	13,869.4
% Ch	5.0	4.6	(3.2)	3.6	9.3	5.2	3.8	4.1	4.5	4.6	4.7	4.7
Other Labor Income												
Oregon	25.6	26.7	24.4	24.8	27.3	29.6	31.7	33.6	35.4	37.3	39.2	41.2
% Ch	4.4	4.2	(8.6)	1.7	10.0	8.3	7.1	6.1	5.5	5.3	5.1	5.0
U.S.	1,417.2	1,473.2	1,426.8	1,478.1	1,615.8	1,699.8	1,763.7	1,835.9	1,918.5	2,006.7	2,100.5	2,199.4
% Ch	5.5	4.0	(3.1)	3.6	9.3	5.2	3.8	4.1	4.5	4.6	4.7	4.7
Nonfarm Proprietor's Income												
Oregon	18.1	18.8	17.4	19.0	19.8	20.4	21.1	21.8	22.5	23.2	23.9	24.7
% Ch	4.4	4.1	(7.7)	9.0	4.3	3.2	3.2	3.2	3.2	3.2	3.2	3.2
U.S.	1,561.6	1,626.3	1,544.9	1,811.2	1,696.2	1,694.4	1,747.5	1,798.8	1,845.0	1,892.1	1,942.8	1,988.8
% Ch	5.5	4.1	(5.0)	17.2	(6.3)	(0.1)	3.1	2.9	2.6	2.6	2.7	2.4
Dividend, Interest and Rent												
Oregon	45.8	47.0	47.3	48.1	49.0	49.4	50.6	52.7	55.3	58.1	61.5	65.3
% Ch	8.3	2.6	0.6	1.7	1.9	0.8	2.5	4.3	4.8	5.2	5.8	6.2
U.S.	3,686.9	3,770.8	3,828.2	3,923.4	4,021.0	4,062.5	4,191.9	4,413.3	4,651.8	4,912.6	5,216.8	5,554.9
% Ch	8.4	2.3	1.5	2.5	2.5	1.0	3.2	5.3	5.4	5.6	6.2	6.5
Transfer Payments												
Oregon	40.0	43.2	55.9	52.3	52.2	53.2	54.9	57.9	60.9	64.0	67.2	70.3
% Ch	5.9	8.0	29.3	(6.4)	(0.1)	2.0	3.1	5.4	5.3	5.1	4.9	4.7
U.S.	2,918.3	3,117.3	3,777.8	3,636.0	3,590.3	3,742.3	3,950.7	4,165.4	4,381.1	4,601.0	4,823.3	5,043.2
% Ch	4.1	6.8	21.2	(3.8)	(1.3)	4.2	5.6	5.4	5.2	5.0	4.8	4.6
Contributions for Social Security												
Oregon	18.5	19.3	18.3	18.2	19.4	21.2	22.8	24.2	25.4	26.8	28.1	29.6
% Ch	3.5	4.2	(5.2)	(0.5)	6.8	8.9	7.9	5.8	5.2	5.3	5.1	5.0
U.S.	733.7	769.6	742.6	765.9	834.7	876.2	907.8	943.8	985.5	1,030.2	1,077.9	1,128.3
% Ch	5.7	4.9	(3.5)	3.1	9.0	5.0	3.6	4.0	4.4	4.5	4.6	4.7
Residence Adjustment												
Oregon	(4.9)	(5.1)	(4.7)	(4.6)	(4.8)	(5.1)	(5.4)	(5.7)	(5.9)	(6.1)	(6.3)	(6.5)
% Ch	4.0	4.0	(8.7)	(1.7)	4.0	6.9	6.5	4.5	3.5	3.9	3.5	3.1
Farm Proprietor's Income												
Oregon	(0.1)	(0.0)	0.0	0.0	0.2	0.3	0.2	0.2	0.3	0.3	0.3	0.3
% Ch	(429.7)	(31.1)	(181.6)	(53.9)	1,350.3	27.2	(22.1)	(1.5)	13.6	6.0	(1.0)	(0.1)
Per Capita Income (Thousands of $)												
Oregon	50.8	52.7	52.9	52.7	54.7	57.2	59.8	62.5	65.2	68.0	70.9	73.9
% Ch	4.9	3.8	0.4	(0.4)	3.9	4.4	4.6	4.6	4.3	4.3	4.3	4.3
U.S.	54.4	56.4	56.9	58.2	60.5	62.4	64.4	66.8	69.5	72.3	75.3	78.5
% Ch	4.9	3.7	1.0	2.4	4.0	3.1	3.2	3.8	4.0	4.1	4.2	4.2

* Personal Income includes all classes of income minus Contributions for Social Security

Jun 2020 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Total Nonfarm												
Oregon	1,912.8	1,942.9	1,717.8	1,736.9	1,810.7	1,898.1	1,969.2	2,004.1	2,028.3	2,049.8	2,069.5	2,088.1
% Ch	2.0	1.6	(11.6)	1.1	4.2	4.8	3.7	1.8	1.2	1.1	1.0	0.9
U.S.	148.9	150.9	144.1	142.7	150.9	154.1	154.5	154.7	155.3	156.1	157.0	157.9
% Ch	1.6	1.4	(4.5)	(0.9)	5.7	2.1	0.3	0.1	0.4	0.5	0.6	0.6
Private Nonfarm												
Oregon	1,618.0	1,644.0	1,417.1	1,444.0	1,514.9	1,600.0	1,666.4	1,696.2	1,715.9	1,733.2	1,748.5	1,763.7
% Ch	3.3	1.6	(13.8)	1.9	4.9	5.6	4.1	1.8	1.2	1.0	0.9	0.9
U.S.	126.4	128.3	121.2	119.8	127.9	130.9	131.1	131.1	131.6	132.2	133.0	133.8
% Ch	1.8	1.5	(5.6)	(1.1)	6.7	2.4	0.2	(0.0)	0.3	0.5	0.6	0.6
Mining and Logging												
Oregon	7.2	6.9	5.2	4.9	5.7	6.1	6.3	6.5	6.8	7.0	7.1	7.2
% Ch	3.3	(4.0)	(25.0)	(5.1)	14.8	7.3	3.6	3.6	3.7	2.9	1.9	1.1
U.S.	0.7	0.7	0.6	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5	0.6
% Ch	7.6	1.2	(20.5)	(33.9)	10.0	9.2	3.4	3.7	3.7	3.2	2.0	1.5
Construction												
Oregon	105.4	109.4	92.7	91.5	96.4	100.9	104.4	106.6	108.3	110.0	111.5	113.1
% Ch	7.8	3.7	(15.3)	(1.3)	5.4	4.6	3.5	2.1	1.6	1.5	1.4	1.4
U.S.	7.3	7.5	7.2	6.8	7.1	7.4	7.6	7.8	7.9	8.0	8.1	8.3
% Ch	4.6	2.9	(3.8)	(6.2)	4.9	4.9	2.4	1.9	1.5	1.3	1.7	2.2
Manufacturing												
Oregon	195.2	198.0	167.1	157.2	168.9	178.1	183.3	186.5	188.2	189.6	190.4	190.5
% Ch	2.7	1.4	(15.6)	(5.9)	7.4	5.5	2.9	1.7	0.9	0.7	0.4	0.0
U.S.	12.7	12.8	12.2	11.2	11.5	11.9	12.0	12.0	12.0	12.0	11.8	11.7
% Ch	2.0	1.2	(4.9)	(7.9)	2.3	3.0	1.3	(0.1)	0.2	(0.5)	(1.1)	(1.1)
Durable Manufacturing												
Oregon	135.5	137.0	113.5	106.0	115.2	121.9	125.9	128.2	129.3	130.0	130.2	130.0
% Ch	2.9	1.1	(17.1)	(6.6)	8.7	5.8	3.2	1.8	0.9	0.5	0.2	(0.1)
U.S.	7.9	8.1	7.6	6.8	7.0	7.3	7.4	7.5	7.5	7.5	7.4	7.3
% Ch	2.7	1.4	(6.1)	(10.4)	2.7	4.1	2.3	0.6	0.8	(0.3)	(1.3)	(1.4)
Wood Products												
Oregon	23.5	23.2	17.0	15.0	17.3	20.0	21.8	22.7	22.9	23.0	23.1	23.1
% Ch	2.5	(1.2)	(27.0)	(11.2)	15.2	15.3	8.9	4.3	1.0	0.3	0.3	0.3
U.S.	0.4	0.4	0.4	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5
% Ch	2.3	0.7	(6.6)	(25.2)	26.2	9.7	5.8	4.3	4.0	1.1	0.0	0.6
Metal and Machinery												
Oregon	39.3	40.2	31.4	29.1	33.3	35.1	36.1	36.9	37.5	37.9	38.0	37.9
% Ch	5.3	2.3	(22.0)	(7.4)	14.4	5.6	2.6	2.2	1.7	1.0	0.2	(0.1)
U.S.	3.0	3.0	2.8	2.5	2.6	2.8	2.9	2.9	2.9	2.9	2.9	2.8
% Ch	3.2	1.2	(7.1)	(9.0)	2.9	5.7	3.3	1.1	1.0	(0.4)	(1.7)	(1.7)
Computer and Electronic Products												
Oregon	37.9	38.6	37.4	36.8	37.4	37.5	37.4	37.1	36.9	36.7	36.4	36.2
% Ch	2.9	1.8	(3.2)	(1.5)	1.6	0.2	(0.3)	(0.7)	(0.5)	(0.6)	(0.7)	(0.5)
U.S.	1.1	1.1	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
% Ch	1.5	2.5	(3.7)	(3.1)	1.2	0.1	0.9	0.5	(0.2)	(0.6)	(1.3)	(1.3)
Transportation Equipment												
Oregon	12.1	12.6	10.2	9.6	10.3	10.8	11.3	11.6	11.8	11.8	11.8	11.7
% Ch	2.2	3.6	(18.9)	(6.0)	7.4	4.5	5.1	2.4	1.7	0.5	0.0	(1.0)
U.S.	1.7	1.7	1.6	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4	1.4
% Ch	3.6	1.9	(8.3)	(14.8)	(0.0)	4.9	1.0	(0.6)	0.3	(0.4)	(1.3)	(2.2)
Other Durables												
Oregon	22.6	22.3	17.6	15.5	16.9	18.5	19.4	19.9	20.2	20.6	20.9	21.0
% Ch	(0.0)	(1.1)	(21.3)	(12.0)	9.2	9.7	4.4	3.0	1.4	1.9	1.5	0.4
U.S.	2.2	2.2	2.1	1.9	2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1
% Ch	1.8	0.8	(4.5)	(12.4)	5.2	3.7	2.5	0.8	1.4	0.1	(0.7)	(0.6)
Nondurable Manufacturing												
Oregon	59.7	61.0	53.6	51.2	53.7	56.2	57.4	58.3	58.9	59.6	60.2	60.4
% Ch	2.2	2.2	(12.2)	(4.4)	4.7	4.7	2.2	1.6	0.9	1.2	1.0	0.4
U.S.	4.7	4.8	4.6	4.5	4.5	4.6	4.6	4.5	4.5	4.4	4.4	4.4
% Ch	0.9	0.8	(2.8)	(3.8)	1.8	1.2	(0.3)	(1.3)	(0.9)	(0.9)	(0.9)	(0.7)
Food Manufacturing												
Oregon	29.9	29.8	28.5	29.2	29.6	29.8	29.8	29.9	30.0	30.2	30.3	30.5
% Ch	0.3	(0.3)	(4.3)	2.2	1.4	0.7	0.3	0.2	0.5	0.6	0.4	0.5
U.S.	1.6	1.6	1.7	1.7	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8
% Ch	1.4	1.3	1.5	(0.7)	3.6	2.7	1.3	(0.0)	0.4	0.2	0.0	0.2
Other Nondurable												
Oregon	29.8	31.2	25.1	22.1	24.1	26.4	27.6	28.4	28.8	29.4	29.8	29.9
% Ch	4.1	4.8	(19.7)	(12.0)	9.2	9.7	4.4	3.0	1.4	1.9	1.5	0.4
U.S.	3.1	3.1	3.0	2.8	2.8	2.8	2.8	2.7	2.7	2.7	2.6	2.6
% Ch	0.7	0.5	(5.1)	(5.5)	0.7	0.3	(1.3)	(2.1)	(1.8)	(1.6)	(1.5)	(1.3)
Trade, Transportation, and Utilities												
Oregon	352.8	357.0	315.8	319.5	325.6	334.0	342.5	344.4	345.2	346.0	346.8	347.5
% Ch	1.1	1.2	(11.5)	1.2	1.9	2.6	2.5	0.6	0.2	0.2	0.2	0.2
U.S.	27.6	27.7	25.4	25.0	27.0	26.7	27.0	26.8	26.7	26.6	26.5	26.4
% Ch	0.8	0.4	(8.5)	(1.6)	8.1	(1.2)	1.3	(0.6)	(0.7)	(0.3)	(0.4)	(0.4)

Jun 2020 - Employment By Industry
(Oregon - Thousands, U.S. - Millions)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Retail Trade												
Oregon	211.5	209.8	181.2	185.2	188.3	191.5	195.2	195.8	196.2	196.9	197.3	197.8
% Ch	0.3	(0.8)	(13.6)	2.3	1.6	1.7	2.0	0.3	0.2	0.3	0.2	0.2
U.S.	15.8	15.6	14.1	14.5	15.9	15.3	15.8	15.6	15.5	15.4	15.3	15.3
% Ch	(0.4)	(0.9)	(9.9)	2.7	9.9	(3.8)	3.2	(0.9)	(1.2)	(0.5)	(0.3)	(0.3)
Wholesale Trade												
Oregon	75.6	76.5	67.9	67.2	69.3	72.7	76.3	77.5	77.7	77.8	78.0	78.1
% Ch	0.9	1.2	(11.3)	(1.0)	3.1	4.9	5.0	1.6	0.2	0.1	0.2	0.1
U.S.	5.8	5.9	5.4	4.9	5.2	5.4	5.3	5.3	5.3	5.3	5.3	5.3
% Ch	0.5	1.1	(9.3)	(8.3)	5.6	3.6	(0.7)	(0.1)	(0.1)	0.1	(0.6)	(0.8)
Transportation and Warehousing, and Utilities												
Oregon	65.7	70.7	66.7	67.1	68.0	69.8	70.9	71.1	71.3	71.3	71.5	71.6
% Ch	4.0	7.6	(5.6)	0.5	1.4	2.6	1.6	0.3	0.2	0.1	0.2	0.1
U.S.	6.0	6.2	5.9	5.6	5.9	6.0	5.9	5.9	5.9	5.9	5.8	5.8
% Ch	4.3	3.1	(4.2)	(5.6)	5.7	1.7	(2.0)	(0.3)	0.1	(0.3)	(0.5)	(0.5)
Information												
Oregon	34.3	35.1	32.0	32.1	32.9	33.2	33.4	33.7	33.9	34.2	34.4	34.7
% Ch	0.3	2.1	(8.6)	0.2	2.3	0.9	0.8	0.7	0.8	0.8	0.8	0.7
U.S.	2.8	2.9	2.8	2.7	2.7	2.7	2.8	2.7	2.7	2.7	2.7	2.7
% Ch	0.9	0.8	(1.4)	(4.6)	1.5	(0.1)	1.3	(1.3)	(0.6)	(1.5)	(0.1)	0.4
Financial Activities												
Oregon	102.2	103.4	99.0	99.3	100.4	101.5	101.9	102.3	102.5	102.7	102.8	102.9
% Ch	2.2	1.1	(4.2)	0.3	1.0	1.1	0.4	0.4	0.2	0.1	0.1	0.1
U.S.	8.6	8.7	8.3	7.6	8.2	8.2	8.0	8.0	8.0	7.9	7.9	7.9
% Ch	1.7	1.8	(4.8)	(9.0)	7.8	0.5	(2.0)	(0.4)	(0.6)	(0.5)	0.1	0.2
Professional and Business Services												
Oregon	249.7	254.3	229.1	225.3	240.7	266.2	287.1	298.8	307.0	313.6	319.3	325.2
% Ch	2.1	1.8	(9.9)	(1.6)	6.8	10.6	7.9	4.1	2.8	2.1	1.8	1.9
U.S.	21.0	21.3	19.8	19.1	23.0	24.0	23.7	24.0	24.5	24.9	25.3	25.7
% Ch	2.2	1.7	(7.1)	(3.3)	20.3	4.1	(1.1)	1.1	2.1	1.8	1.7	1.4
Education and Health Services												
Oregon	295.4	301.5	269.6	289.0	298.7	309.2	320.6	327.2	331.0	334.3	337.4	340.9
% Ch	8.2	2.1	(10.6)	7.2	3.4	3.5	3.7	2.1	1.2	1.0	1.0	1.0
U.S.	23.6	24.2	24.0	24.0	25.6	25.9	25.5	25.5	25.4	25.5	25.7	25.9
% Ch	1.9	2.3	(0.5)	(0.3)	7.0	0.8	(1.4)	(0.2)	(0.1)	0.4	0.8	0.9
Educational Services												
Oregon	36.5	36.6	32.2	35.2	35.3	35.4	35.5	35.6	35.7	35.7	35.8	35.8
% Ch	1.3	0.3	(12.2)	9.5	0.3	0.3	0.3	0.3	0.1	0.1	0.1	0.1
U.S.	3.7	3.8	3.6	3.9	4.1	4.0	3.8	3.6	3.5	3.5	3.5	3.4
% Ch	1.2	1.3	(5.0)	8.3	6.1	(3.1)	(5.5)	(3.5)	(2.3)	(1.5)	(1.1)	(1.0)
Health Care and Social Assistance												
Oregon	258.9	264.9	237.4	253.7	263.4	273.8	285.1	291.6	295.4	298.5	301.7	305.0
% Ch	9.3	2.3	(10.4)	6.9	3.8	3.9	4.1	2.3	1.3	1.1	1.0	1.1
U.S.	19.9	20.4	20.5	20.1	21.5	21.9	21.7	21.8	21.9	22.0	22.3	22.5
% Ch	2.1	2.5	0.3	(1.9)	7.2	1.6	(0.6)	0.4	0.2	0.7	1.1	1.2
Leisure and Hospitality												
Oregon	211.4	213.8	150.3	166.9	184.9	207.6	222.7	225.8	228.3	230.8	233.1	235.7
% Ch	2.4	1.1	(29.7)	11.0	10.8	12.3	7.3	1.4	1.1	1.1	1.0	1.1
U.S.	16.3	16.6	15.2	17.5	16.3	17.8	18.3	18.2	18.3	18.5	18.7	18.9
% Ch	1.5	1.7	(8.5)	15.4	(6.6)	8.9	2.7	(0.4)	0.5	1.3	1.1	1.0
Other Services												
Oregon	64.4	64.7	56.4	58.1	60.7	63.3	64.1	64.3	64.6	65.1	65.6	66.2
% Ch	1.4	0.5	(12.9)	3.1	4.4	4.3	1.3	0.3	0.4	0.8	0.7	0.9
U.S.	5.8	5.9	5.7	5.6	6.0	5.9	5.8	5.7	5.7	5.7	5.7	5.7
% Ch	1.1	1.1	(3.2)	(1.5)	6.4	(0.8)	(3.1)	(1.1)	(0.4)	0.1	0.4	0.4
Government												
Oregon	294.8	298.9	300.7	292.9	295.9	298.1	302.8	308.0	312.4	316.6	321.0	324.4
% Ch	(4.8)	1.4	0.6	(2.6)	1.0	0.8	1.6	1.7	1.4	1.3	1.4	1.0
U.S.	22.4	22.6	22.9	22.9	23.1	23.2	23.4	23.5	23.7	23.8	24.0	24.1
% Ch	0.4	0.6	1.2	0.1	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Federal Government												
Oregon	28.1	28.5	28.9	27.7	27.7	27.8	27.8	27.8	27.9	27.9	27.9	28.0
% Ch	(0.3)	1.6	1.2	(4.2)	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.1
U.S.	2.8	2.8	3.0	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8	2.8
% Ch	(0.2)	1.2	4.6	(4.0)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
State Government, Oregon												
State Total	39.5	40.7	41.1	40.9	41.7	41.9	42.2	42.5	42.9	43.5	44.1	44.5
% Ch	(29.8)	3.0	1.2	(0.5)	1.8	0.6	0.6	0.8	1.1	1.3	1.4	0.8
State Education	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
% Ch	1.9	5.2	5.0	0.2	0.8	0.5	0.8	0.5	0.2	0.4	0.5	0.5
Local Government, Oregon												
Local Total	227.2	229.7	230.7	224.3	226.5	228.5	232.8	237.7	241.6	245.2	249.0	252.0
% Ch	0.8	1.1	0.4	(2.8)	1.0	0.9	1.9	2.1	1.7	1.5	1.5	1.2
Local Education	132.7	134.0	135.0	130.2	131.6	132.5	134.7	137.2	139.2	141.0	142.4	143.4
% Ch	(0.0)	0.9	0.8	(3.6)	1.1	0.6	1.7	1.8	1.4	1.3	1.0	0.7

Jun 2020 - Other Economic Indicators

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
GDP (Bil of 2012 $),												
Chain Weight (in billions of $)	18,638.2	19,073.1	18,047.2	19,189.0	19,955.6	20,279.7	20,549.2	20,935.3	21,359.4	21,800.6	22,272.8	22,749.9
% Ch	2.9	2.3	(5.4)	6.3	4.0	1.6	1.3	1.9	2.0	2.1	2.2	2.1
Price and Wage Indicators												
GDP Implicit Price Deflator,												
Chain Weight U.S., 2012=100	110.4	112.3	114.0	115.6	117.3	119.6	122.3	125.0	127.8	130.7	133.6	136.7
% Ch	2.4	1.8	1.5	1.4	1.5	2.0	2.2	2.2	2.2	2.3	2.3	2.3
Personal Consumption Deflator,												
Chain Weight U.S., 2012=100	108.1	109.7	110.6	112.2	114.4	117.0	119.5	122.1	124.5	127.0	129.4	131.8
% Ch	2.1	1.4	0.9	1.5	2.0	2.2	2.2	2.1	2.0	1.9	1.9	1.9
CPI, Urban Consumers,												
1982-84=100												
West Region	263.3	270.3	272.3	278.1	285.7	293.5	300.9	308.3	315.8	323.2	330.6	338.2
% Ch	3.3	2.7	0.7	2.1	2.7	2.7	2.5	2.5	2.4	2.3	2.3	2.3
U.S.	251.1	255.7	257.4	262.7	269.8	277.1	283.8	290.6	297.2	303.7	310.2	316.8
% Ch	2.4	1.8	0.7	2.1	2.7	2.7	2.4	2.4	2.3	2.2	2.1	2.1
Oregon Average Wage												
Rate (Thous $)	55.4	57.1	59.7	59.6	61.4	64.0	66.8	69.7	72.6	75.7	78.9	82.2
% Ch	3.7	3.0	4.5	(0.1)	3.0	4.2	4.4	4.3	4.3	4.3	4.2	4.2
U.S. Average Wage												
Wage Rate (Thous $)	59.7	61.6	62.4	65.3	67.5	69.5	72.0	74.8	77.9	81.1	84.4	87.8
% Ch	3.4	3.2	1.4	4.6	3.4	3.0	3.5	4.0	4.1	4.1	4.1	4.1
Housing Indicators												
FHFA Oregon Housing Price Index												
1991 Q1=100	423.1	443.2	457.5	462.2	473.2	488.0	503.6	519.2	535.4	553.0	572.5	592.4
% Ch	7.8	4.8	3.2	1.0	2.4	3.1	3.2	3.1	3.1	3.3	3.5	3.5
FHFA National Housing Price Index												
1991 Q1=100	260.5	274.1	283.9	289.1	296.0	304.0	312.3	320.7	329.1	337.9	347.3	357.6
% Ch	6.5	5.2	3.6	1.8	2.4	2.7	2.7	2.7	2.6	2.7	2.8	3.0
Housing Starts												
Oregon (Thous)	19.6	20.7	16.2	16.7	18.9	21.4	21.9	22.2	21.9	21.9	21.8	21.9
% Ch	1.4	5.9	(21.7)	3.0	13.3	13.1	2.3	1.4	(1.2)	(0.0)	(0.4)	0.2
U.S. (Millions)	1.2	1.3	1.1	1.1	1.3	1.2	1.2	1.2	1.2	1.1	1.1	1.1
% Ch	3.4	3.9	(17.0)	4.0	12.3	(1.2)	(2.8)	0.0	(2.7)	(2.4)	(0.3)	0.3
Other Indicators												
Unemployment Rate (%)												
Oregon	4.1	4.1	15.3	14.7	11.4	7.6	4.6	4.2	4.3	4.4	4.3	4.3
Point Change	0.0	(0.0)	11.2	(0.6)	(3.3)	(3.8)	(3.0)	(0.4)	0.2	0.0	(0.0)	(0.0)
U.S.	3.9	3.7	8.0	7.9	4.3	3.6	4.0	4.3	4.3	4.3	4.3	4.2
Point Change	(0.5)	(0.2)	4.4	(0.2)	(3.6)	(0.7)	0.4	0.3	0.0	(0.0)	(0.0)	(0.0)
Industrial Production Index												
U.S, 2012 = 100	108.6	109.5	96.1	96.4	101.1	103.0	104.0	105.7	107.9	109.9	111.8	113.8
% Ch	3.9	0.9	(12.2)	0.3	4.8	2.0	1.0	1.6	2.0	1.8	1.7	1.8
Prime Rate (Percent)	4.9	5.3	3.5	3.3	3.3	3.3	3.3	3.3	3.6	4.2	4.7	5.2
% Ch	19.7	7.7	(33.0)	(8.2)	0.0	0.0	0.0	0.3	11.9	13.7	12.1	10.8
Population (Millions)												
Oregon	4.20	4.24	4.27	4.29	4.32	4.36	4.40	4.43	4.47	4.51	4.54	4.58
% Ch	1.3	1.0	0.7	0.6	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
U.S.	327.7	330.1	332.4	334.7	337.1	339.4	341.6	343.9	346.1	348.3	350.5	352.6
% Ch	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.6	0.6	0.6	0.6
Timber Harvest (Mil Bd Ft)												
Oregon	4,064.0	3,860.0	3,156.5	3,387.9	3,553.5	3,635.9	3,692.8	3,787.6	3,821.6	3,847.3	3,871.3	3,895.5
% Ch	5.5	(5.0)	(18.2)	7.3	4.9	2.3	1.6	2.6	0.9	0.7	0.6	0.6

CASE: UG 390
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Curtis Dlouhy. I am a Senior Economist employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement can be found in Exhibit Staff/301.

Q. What is the purpose of your testimony?

A. My testimony discusses Cascade Natural Gas's (Cascade or Company) Test Year pension and post-retirement medical benefits and related issues. I make recommendations regarding the Company's Test Year pension expense.

Q. Did you prepare any exhibit for this docket?

A. Yes. I prepared Exhibit Staff/302, regarding expected ROAs and discount rates for energy utilities in Oregon.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. PENSION, OTHER POST-RETIREMENT BENEFITS AND RELATED

Pension and Related Issues

Q. Does the Company address its pensions and post-retirement accounts in its opening testimony?

A. No, it does not.

Q. When did Cascade Natural Gas file its initial application in this proceeding?

A. The Company's initial filing was on March 31, 2020.

Q. Does the Company discuss the parameters it uses to calculate its pension and post-retirement benefit expenses in the Standard Discovery Requests?

A. No, it does not. In their responses to SDR 59-60, the Company noted that its parent company, MDU, was in the process of changing from one actuary to another and was unable to provide responses to the data requests. On June 22, Staff submitted follow-up data requests (Staff DR Nos. 250-256) to compel the Company to answer SDR 59-60. The Company responded to these requests on July 10, 2020.

Q. What does the Company use for its Test Year to calculate its pension and other post-retirement benefit expenses?

A. In an attachment to their response to Staff DR No. 252, Cascade indicates that its test year is December 31, 2019 - December 31, 2020.

Q. Does the Company use Financial Accounting Standards (FAS) Number 87 (FAS 87) in calculating its pension costs?

A. Yes, it does.[1]

Q. Does the Company use Financial Accounting Standards (FAS) Number 106 (FAS 106) in calculating its other post-retirement benefit expenses?

A. Yes, it does.

Q. Does Staff have any recommendations regarding the Company's accounting treatment of pension costs and other post-retirement benefit expenses for ratemaking purposes?

A. Yes. My adjustments are related to the Company's treatment of the discount rate. I discuss them further in my testimony.

Q. How many employees does the Company have on its pension and post-retirement benefit plans?

A. Cascade has two distinct qualified pension plans for different employee groups and a shared post-retirement benefit plan for all employees. One pension plan is for general employees and is called the Cascade Employee Plan, and the other is for senior executives and is called Cascade SERP. The Cascade Employee Plan is the larger plan with 477 participants as of December, 31, 2019, and Cascade SERP has 16 as of the same date. Only the costs from the Cascade Employee Plan are allocated to Oregon.

Q. What were the Company's pension and post-retirement expenses for the test year?

[1] FAS 87 is now part of the FASP Accounting Standards Codification, Compensation-Retirement Benefits (Topc 715)

A. MDU's actuaries projected net periodic incomes rather than net expenses for both its pension and post-retirement welfare plans. MDU's actuaries project that the Cascade Employee Plan will earn a Net Pension Income of $463,361 for the Test Year and a Net Post-Retirement Welfare Plan Income of $362,365. The values of these allocated to Oregon for the 2020 Test Year are $115,053 and $89,975, respectively.[2]

Q. What actuarial parameters are relevant to calculating pension and post-retirement benefit expenses or incomes?

A. There are two relevant parameters: the expected return on assets (ROA) and the discount factor.

Q. What is the ROA and how does it affect the projected pension and post-retirement benefit costs?

A. The ROA is the rate of return on assets used to fund a pension plan or a post-retirement benefits plan. A higher expected ROA represents that a plan is expected to generate more money from its assets, which ultimately translates into lower benefit obligation cost or higher income.

Q. What is a typical expected ROA used by Oregon utility companies to calculate benefit obligations?

A. In Exhibit 302, I present the expected ROA used in 2019 by each of the five private utilities that provide electricity or natural gas in Oregon apart from Cascade Natural Gas. The values for each of the five other utilities come from each company's SEC 10-K form filing for 2019 while Cascade's ROA comes

[2] Cascade response to Staff DR No. 252.

from its response to Staff DR No. 252. For a pension plan, the average of ROA for all five companies except Cascade is 6.83 percent, the lowest ROA is 5.9 percent and the highest ROA is 7.5 percent. For other post-retirement expenses, the average ROA for all companies except Cascade is 4.92, the lowest ROA is 0 percent, and the highest ROA is 6.75 percent.

Northwest Natural Gas Company (NW Natural) does not hold any assets in its post-retirement benefits plan, and therefore its ROA is 0 percent. When NW Natural is excluded, the average ROA used by the four remaining utilities is 6.15 percent.

Q. What ROA values are used by Cascade to calculate pension and other post-retirement benefit obligations?

A. In the test year, Cascade uses a long-run ROA of 6.25 percent for its pension plan and 5.75 percent for other post-retirement benefits.

Q. Do you believe that these are acceptable values?

A. Yes, for both the its pension and other post-retirement benefit plans, the Company uses expected long-run ROA values that are within the range of the minimum and maximum values of other Oregon regulated utilities. The long-run ROA used by the Company is slightly below average of its peers' 2019 values. Staff believes a conservative ROA relative to its peers' mean in 2019 is prudent given the economic downturn resulting from the COVID-19 pandemic.

Q. What is the discount rate and how does it affect the projected pension and post-retirement benefit costs?

A. The discount rate is the expected market interest rate for the relevant asset. It is often used to calculate the present value of an asset that provides a stream of revenue. As a discount rate rises the value of the assets in the plan falls, which ultimately causes the projected benefit expense to fall.

Q. What is a typical discount rate used by Oregon utility companies to calculate benefit obligations?

A. In Exhibit 302, I also present the discount rates used by each of the five other regulated electric and gas utilities in Oregon in 2019 and the discount rates used by Cascade in its Test Year. The values can all be found on each company's SEC 10-K form filing. For a pension plan, the average discount rate for all companies except Cascade is 3.92 percent, the lowest discount rate is 3.43 percent, and the highest discount is 4.55 percent. For other post-retirement expenses, the average discount rate for all firms except Cascade is 3.82, the lowest ROE is 3.19 percent, and the highest ROE is 4.45 percent.

Q. What discount rates are used by Cascade to calculate its pension and other post-retirement benefit obligations?

A. Cascade uses a discount rate of 2.98 percent for its pension plan and 2.97 percent for its post-retirement benefits plan.

Q. How do these values compare to other gas and electric utilities in Oregon?

A. For its pension plan and other post-retirement benefits plan, the discount rate used by Cascade is lower than all other regulated natural gas and electric utilities in Oregon. Additionally, the Company's pension discount rate is 94 basis points lower than the mean discount rate used by all five other regulated gas and electric utilities in Oregon, and the Company's discount rate used for its post-retirement benefits expenses is 85 basis points lower than the mean discount used by the other five regulated gas and electric utilities in Oregon.

Q. Do you believe that these are acceptable values?

A. No, these rates are far too low and artificially lower the income from the Company's pension and post-retirement welfare accounts. These discount rates are both also a full 106 basis points less than the discount rates used in the Company's Base Year pension and post-retirement benefit accounting. While some year to year change is expected as market conditions change, this rate is a full 42 basis points lower than the next-lowest rate used to calculate expense obligation since 2016.[3]

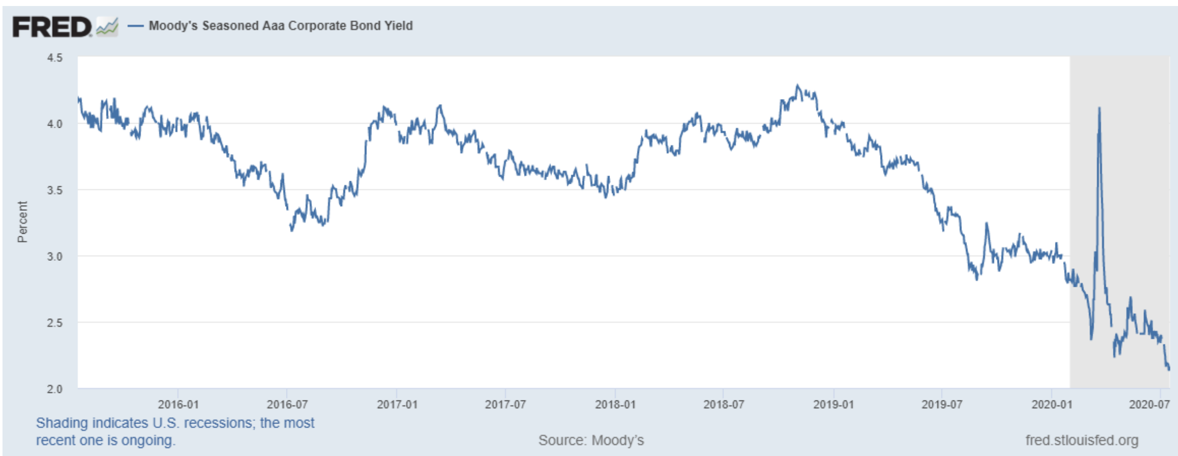
Q. Have there been any changes to the market that necessitate updating the Company's discount rate from the base year level?

A. Yes. The onset of the COVID-19 pandemic has led to interest rates falling in all markets across the United States. As an example, I include a time series of the daily yields for Aaa-rated Corporate Bonds from Moody's for the last five years in Figure 1, below. In the Company's response to Staff DR No. 254, it notes the Company chose discount rates that are "reflective of rates in effect as of the measurement date for high-quality corporate bonds whose maturity dates and amounts would be the same as the timing and amount of the expected future benefit payments". Thus, Figure 1 can be used as a

[3] Cascade response to Staff DR No. 252.

reasonable proxy for a proper discount rate for Cascade. Since around the time the COVID-19 pandemic began, there has been an obvious drop in the yield of Aaa Corporate bonds, and this does necessitate a downward revision in the Company's discount rate.

Figure 1[4]



Q. Is this drop in other interest rates reason enough to justify such a large change in the Company's discount factor? Why or why not?

A. No. While it would be naïve to assume that the appropriate discount rate for Cascade would fall lock-step with the time series in Figure 1, the magnitude of the changes between the Company's discount rate and the yields shown above don't match up. From January 1, 2020, to July 1, 2020, the corporate bond yield fell from 3.04 percent to 2.40 percent, a change of 64 basis points. Relative to the Base Year of 2019, the Company's discount rates fell 106 basis points.

[4] Figure created from the data compiled by the St. Louis FRED. Accessible at: https://fred.stlouisfed.org/series/DAAA.

Q. What adjustments should be made?

A. Staff recommends that the Company raise their discount rates to 3.4 and 3.39 percent for their pension plan and post-retirement benefit plans, respectively. This represents a drop from the Company's 2019 discount rate of 64 basis points. It is meant to mimic the 64 basis point drop in yields for Corporate Aaa-rated bonds in the first six months of 2020.

Q. Why adjust the discount rate but not the estimated long-run return on assets?

A. Staff notes that, unlike the return on assets, the discount rate is strictly an actuarial construct that is unrelated to the actual cash flow of the plan trust. Put another way, although the discount rate is useful for planning purposes, it has no real relation to a Company's actual cash flow. Therefore, one must be diligent to select a discount rate that reflects interest rates in the future, but does not over allocate costs.

Q. What adjustment does Staff recommend and how did Staff calculate it?

A. At this time, Staff recommends an adjustment of $23,621.47 but notes that it has some concerns about the values provided by Cascade.

Q. What concerns are Staff referring to?

A. Raising the discount rate should raise income (or lower costs) from pension or post-retirement benefit plans. However, in its response to Staff DR No. 253, the Company states that raising the discount rate *lowers* income for its qualified pension plan by $28,318 and *raises* costs for its unqualified pension plan by $1,475, but raises income for its other post-retirement benefits plan by

$29,665. This is not only inconsistent with expected effects of changing the discount rate but is also inconsistent within the Company's own accounts.

Q. How did Staff address these concerns?

A. Staff assumed that Cascade incorrectly said raising the discount rate lowers income and raises costs for its pension plans. In order to calculate the adjustment, Staff assumed that the Company meant to say "raises income" and "lowers costs", and plans to issue a data request to confirm this.

Q. After adjusting for these concerns, how does Staff calculate its recommended adjustment?

A. First, Staff adjusted for the likely data error addressed in the previous question. Next, Staff noted that a .25 percentage point rise in the discount factor would lead to a company-wide rise in income of $59,458. Staff multiplied this number by 24.83% to allocate this adjustment to Oregon using the allocation factor provided in Cascade's response to Staff DR No. 251, which led to an Oregon allocation of $14,763.42. Finally, Staff multiplied the Oregon allocation by 1.6 to reflect that Staff recommends raising the discount factor by .40 percentage points instead of .25 percentage points, which comes to a total adjustment of $23,621.47.

Q. Does this conclude your testimony?

A. Yes.

CASE: UE 390
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 301

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Curtis Dlouhy
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance, and Audit Division
ADDRESS:	201 High St. SE, Ste. 100 Salem, OR 97301-3612
EDUCATION:	PhD, Economics University of Oregon, Eugene, OR Master of Science, Economics University of Oregon, Eugene, OR Bachelor of Arts, Economics & Math Nebraska Wesleyan University, Lincoln, NE
EXPERIENCE:	I have been employed by the Oregon Public Utility Commission (OPUC) since June 2020 in the Energy Rates, Finance, and Audit Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. Prior to working for the Commission I was employed by the University of Oregon as a graduate employee where I taught classes in Intermediate Microeconomics, Industrial Organization and Antitrust Economics. My PhD dissertation covered various topics in fossil fuel markets ranging from coal mine closure, electricity choices under carbon taxes and coal transport via railroad.

CASE: UE 390
WITNESS: CURTIS DLOUHY

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 302

Pension and OPEB Peer Screen

July 30, 2020

Staff Exhibit 302

Is

Filed in electronic format

Pension

Company	Type	2019 Discount Rate	LRROROA	Source
CNG	Gas	2.98%	6.25%	Response to Staff DR 252
AVA	Gas	3.85%	5.90%	SEC 10k
NWN	Gas	3.50%	7.25%	SEC 10k
PAC	Elec	4.25%	6.50%	SEC 10k
PGE	Elec	3.43%	7.00%	SEC 10k
IPC	Elec	4.55%	7.50%	SEC 10k
	Mean w/o CNG	3.92%	6.83%	
	Min	3.43%	5.90%	
	Max	4.55%	7.50%	

Other Post-Retirement Expenses

Company	Type	2019 Discount Rate	LRROROA	Source
CNG	Gas	2.97%	5.75%	Response to Staff DR 252
AVA	Gas	3.89%	5.70%	SEC 10k
NWN	Gas	3.42%	**0.00%**	SEC 10k
PAC	Elec	4.15%	6.25%	SEC 10k
PGE	Elec	3.19%	5.88%	SEC 10k
IPC	Elec	4.45%	6.75%	SEC 10k
	Mean w/ CNG or NWN		6.15%	
	Mean w/o CNG	3.82%	4.92%	
	Min	3.19%	**0.00%**	
	Max	4.45%	6.75%	

CASE: UG 390
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION

STAFF EXHIBIT 400

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Kathy Zarate. I am a Utility Economist employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/401.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's review of Cascade Natural Gas Corporation's (Cascade or Company) expense for customer support programs, Energy Trust of Oregon funding, and gains or losses on sales utility property for purposes of this general rate case.

Q. Do you prepare an exhibit as part of your testimony?

A. Yes, I have prepared the following exhibits:

Exhibit 401—Witness Qualification Statement
Exhibit 402—Company responses to Staff Data Request Nos. 174, 175,180, 181 and 182.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. CUSTOMER SUPPORT PROGRAMS

Q. Can you describe Cascade's customer support programs?

A. Yes. Cascade provides a number of programs to assist customers in meeting their energy bill obligations. In Oregon, Cascade provide three programs:[1]

1. Low-income Home Energy Assistance Program.
2. Oregon Low Income Bill Pay Assistance Program (OLIBA) and;
3. Winter Help.

The first program is federally funded. The second program is funded through Cascade's public purpose charge. The third program is funded through donations from Cascade and its customers. The programs are administered by five agencies identified by Cascade Natural Gas. These agencies are:[2]

1. Community Connection of Northeast Oregon,
2. Neighbor Impact,
3. Klamath and Lake Community Action Services,
4. Community in Action, and
5. Community Action Program of East Central Oregon.

Q. For the agencies that administer the program, is there a control on the level of administrative costs that can be charged?

A. Yes, the administrative costs are assumed to be twenty percent.[3]

Q. Are there are other customer support programs that Cascade provides for its customer in Oregon?

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[1] See Staff/402, Cascade Natural Gas response to Staff DR No. 180.
[2] See Staff/402, Cascade Natural Gas response to Staff DR No. 174.
[3] See Staff/402, Cascade Natural Gas response to Staff DR No. 175.

A. Yes. Cascade has the following programs related to low-income customers:[4]

1. Budget Payment Plan for Payments of Gas Bills.
2. Oregon Low-Income Energy Conservation Program.

The Oregon Low-Income Energy Conservation Program is also funded by Cascade's public purpose charge.

Q. For the programs funded through public purpose charge, is the public purpose charge levied on Cascade's natural gas bills?

A. Yes. Cascade obtains the public purpose charge funding from its retail customers to pay for the OLIBA and Oregon Low-Income Energy Conservation Program through its Schedule 31 Public Purpose Charge (PPC). The PPC is equal to a percentage of revenues assessed as a line item on customer bills taking service under rate schedules 101 (General Residential Service), 104 (General Commercial Service), 105 (General Industrial Service), 111 (Large Volume General Service), and 170 (Interruptible Service). The Company listed its programs and its funding sources, including the public purpose charge in its response to Staff Data Request No. 174, a copy of which is attached as Exhibit 402.

Q. Can you describe Cascade's low-income Winter Help Program?

A. The Winter Help program provides bill payment assistance to low-income customers through donations provided by the Company and its customers' donations. The Winter Help program began in 1989.[5]

[4] See CNGC/100, Kivisto/9.
[5] CNGC/100-Kivisto/9; Staff/402, Cascade response to Staff DR No.180; and https://www.cngc.com/customer-service/low-income-assistance-programs/

Q. Can you describe Cascade's low-income budget payment plan?

A. Yes. The Company continues to offer a Budget Payment Plan, which provides an option to customers to make equal monthly payments. Thus, under the plan, winter bills will be lower than if billed based on actual usage, and summer bills will be correspondingly higher. The Budget Payment Plan makes it easier for customers to budget their expenditures for natural gas, as it is a flat amount per month and is adjusted once a year.[6]

Q. Can you describe the level of customer participation in the Company's Budget Payment Plan?

A. Yes, according to Cascade, CNGC/100, Kivisto/10, as of December 31, 2019, 5,792 or 7.5 percent of Oregon customers participate in the Budget Payment Plan.

Q. In order to move more quickly to distribute funds to customers in need, did you ask the Company whether they have considered inserting an emergency clause in their tariffs or rules?

A. Yes. The Company states that it has not considered such an action as it could result in customers being treated differently.[7]

Q. In addition to these programs, did Cascade take any actions related to impact on customers from the COVID-19 pandemic?

A. Yes. Cascade has taken several actions to assist customers during the

[6] See CNGC/100-Kivisto/10.
[7] See Staff/402, Cascade Response to Staff DR Nos. 176 and 177, respectively.

economic and health hardships caused by COVID-19, including:[8]

- Suspending disconnections for nonpayment and late fees.
- Providing greater opportunities for customers to extend payment plans or arrangements beyond the normal timeframe on a case-by-case basis.
- Creating a new hardship grant using Cascade's Winter Help donation fund, which allows a grant up to $100 toward a residential customer's past due balance when the customers inform the Company that they have been negatively impacted by COVID-19.
- Actively attempting to contact customers by telephone who have a past due balance over 60 days to set up payment plans or arrangements.
- Continuing to advise customers who indicate they are having difficulty paying their bill to contact Community Action or 2-1-1 for information on energy assistance and resources for other household needs.[9]
- Asking to modify its Tariff rules to give its partner agencies greater flexibility to determine who qualifies for OLIBA assistance.[10]

Q. How has the COVID-19 pandemic impacted the Company's assistance programs?

A. The Company reports that there is an increasing number of customers across all communities in its service territory who are experiencing job loss, reduction of work hours, or illness and that these customers may be less likely to pay their monthly bills in full, in part, or on time. This inability to pay will reduce or

[8] See Staff/402, Cascade Response to Staff DR No. 178.
[9] See Staff/402, Cascade Response to Staff DR No. 178.
[10] Cascade Natural Gas Company, Docket No. ADV 1140 (June 29, 2020).

delay the amount collected for the PPC that funds OLIBA. At the same time, customer needs for OLIBA funds will continue to increase for the next several months and exceed grant spending seen in prior program years. To address the increased need, Cascade separately filed a revision to its OLIBA to provide its partner agencies more flexible guidelines to apply to determine customer eligibility.[11]

In addition, Cascade has filed a request to defer "uncontrollable" costs that may occur as a result of the COVID-19 pandemic.[12] Mitch Moore provides further discussion regarding the Company's deferral application.

Q. What is the Company's proposal for low-income programs in this docket?

A. Cascade does not propose any changes to its low-income programs in this rate case.

Q. Did you have anything else to add with regard to the Company's Customer Support programs?

A. No**.**

Q. Did you make any adjustments to Cascade's Test Year regard this issue?

A. No.

[11] See Cascade Natural Gas Co., Docket No. ADV 11-40, (June 29, 2020).
[12] In the Matter of Cascade Natural Gas Company Application to Defer Costs Associated with COVID-19 Public Health Emergency (UM 2072) (filed March 26, 2020).

ISSUE 2. ENERGY TRUST OF OREGON FUNDING

Q. Can you describe Energy trust of Oregon?

A. Yes. The Oregon Public Utility Commission (OPUC) designated Energy Trust of Oregon (Energy Trust) to administer the conservation and renewable resource components of the statutorily imposed public purpose charge (PPC) for customers of electric utilities in 1999. Energy Trust helps utilities diversify Oregon's energy mix with generation from small scale renewable energy systems. Energy Trust began operation in March 2002,[13] charged by the OPUC with investing in cost-effective energy efficiency, helping to lower the above-market costs of renewable energy resources, delivering services with low administrative and program support costs, and maintaining high levels of customer satisfaction.

Although natural gas utilities are not statutorily required to impose a PPC to fund low-income and conservation programs, all three natural gas utilities operating in Oregon do so pursuant to settlement agreements approved by the Commission. Funds collected through Cascade's PPC each month are used for conservation and renewable energy projects, low-income weatherization, low-income housing and low-income utility bill assistance.[14]

Q. Does Cascade provide conservation programs through the Energy Trust of Oregon?

[13] Report to legislative Assembly on Public Purpose Charge Receipts and Expenditures, Period July1, 2017 – June 30, 2019.
[14] https://www.cngc.com/customer-service/low-income-assistance-programs/CascadeNaturalGasispleased,dwellingsheatedwithnaturalgas.

A. Yes.[15]

Q. Can you describe at least one of the conservation-related programs that Cascade offers through the Energy Trust?

A. Yes, I will describe Weatherization Assistance. Cascade Natural Gas partners with the community action and low-income agencies and offers home weatherization and energy efficiency improvements to income-qualified residential dwellings heated with natural gas. The low-income weatherization portion of the Public Purpose Charge provides reliability through Schedule 33, but the funds have an annual limit for low-income weatherization, which is $225 per household.[16]

Q. Did you make any adjustments to Cascade's conservation program 2020 test-year expenditures?

A. No.

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[15] CNGC/100, Kivisto/9.
[16] See OPUC Docket UM 2025 and Schedule 33.

ISSUE 3. PROPERTY

Q. Please discuss your review of gains or losses on sales of utility property.

A. For my review of Cascade's treatment of gains or losses on utility property within this general rate case filing, I reviewed Cascade's recent history of property sales filings before the Commission, spoke with Cascade personnel, and sent Staff data requests.

Q. What is the historical treatment for Cascade property sales by the Commission?

A. Unlike some of the other utilities operating in Oregon, the Company does not maintain a property sales balancing account as a means to flow through the net gains and losses to customers resulting from sale of property. Instead, the Company has simply offset accumulated depreciation with gains from property sales.[17]

Q. Has the Company sold any property since the last general rate case, or any property in Washington allocated to Oregon?

A. In response to Staff Data Request Nos. 181 and 182, copies of which are attached as Staff/402, the Company states that it sold no property in Oregon or any property in Washington that was allocated to Oregon.[18] With no property sold, there are no gains or losses to report or record.

Q. Did you propose any adjustments for Cascade on this issue?

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[17] See e.g., In the Matter of Cascade Natural Gas Company Application requesting approval of the sale of Ontario, Oregon business office property (UP 281), Order No. 12-286.

[18] Staff/402, Cascade responses to Staff DR Nos. 181 and 182.

A. No.

Q. Does this conclude your opening testimony?

A. Yes.

CASE: UG 390
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 401

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Kathy Zarate
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Economist Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE., Suite 100 Salem, OR. 97301
EDUCATION:	Bachelor of Arts, Economics Oregon State University, Corvallis, Oregon Bachelor Degree in Law Republic University, Santiago, Chile
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon (OPUC) since April 2016, with my current position being a Utility Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of regulatory issues such as review of affiliated interest filings, property sales applications and rate proposals. I have approximately 10 years of professional experience in contracting and audit review work, including:

I spent six years as a contract specialist for 3 Com, Santiago, Chile, with responsibilities including coordinating and preparing contracts with resellers, reviewing company books and records, coordinating logistics in business, and working as or with anExpert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst.

I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

I have served as a Principal Analyst at the OPUC for the determination of Energy Property Sales (Oregon Revised Statute 757.140) for the past 3 years. In this position, I investigated, analyzed, and calculated energy cost and impact.

<u>I also support work related to power costs,</u> plant, and associated impact on customer rates. I have reviewed, calculated, and analyzed QFs, wheeling, forced outage rates and Scheduled maintenance outages, PURPA, Solar forecast, wind forecast (UE 366).

I has worked on power cost issues in the below representative cases:

1. UE 366 Idaho Power.
2. UE 375 PacifiCorp
3. UE 377 Portland General Electric PGE

I generally conduct case investigation and analysis on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are:

- PacifiCorp
- PGE
- Northwest Natural Gas
- Idaho Power
- Avista Corp
- Cascade Gas

General Rate Cases: I have been a part of almost every energy rate case since I joined the Oregon PUC in 2016. Historically, my review has included, property sales, material and supply, donations, marketing cost. Currently, my review includes property sales and low-income issues. My work is generally represented in the last four General Rate cases, as examples:

- UG 388 NW Natural
- UE 374 Pacificorp
- UG 389 Avista
- UG 390 Cascade

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Low-Income: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 2058.

Auditing, Interest Rate, Affiliated Interest: I audited cost of capital and financial components (IU 437)

CASE: UG 390
WITNESS: KATHY ZARATE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 402

Exhibits in Support
Of Opening Testimony

July 30, 2020

Staff Exhibit 402

Data Response OPUC -174

Is

Filed in electronic format

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 175

175. Please provide a copy and detailed narrative explaining the contract for each agency partner currently working on Low–income programs if you have any.

Response:

Attached you will find a copy of the Oregon Low-Income Bill Pay Assistance Program Administrative Agreement in use for the current program year with each agency partner. This program is funded by the Public Purpose Charge which is applied to the bills of all core customers in Oregon and is administered through Community Action Agencies in our service territory. It offers customers the opportunity to receive a grant and mirrors the qualification protocols promulgated by the OHCS and the Low-Income Home Energy Assistance Act of 1981 and subsequent amendments as outlined in the OHCS Omnibus Contract provided that this program allows agencies to use a maximum household income eligibility of up to 150% of the Federal Poverty Guidelines. Each agency partner is compensated for administrative costs in the amount of 20% of per grant awarded.

The Administrative Agreement provides the program detail requested. The agreement is identical for each partner. OPUC-175.pdf

Docket UG 390

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 180

180. Please provide the list of each program that Cascade has for their Low–income customers.

Response:

We offer three programs for our low-income customers:

Low-Income Home Energy Assistance Program (federal program)
Oregon Low Income Bill Pay Assistance Program (PPC rate-based program)
Winter Help (funded by company and customer donations)

https://www.cngc.com/customer-service/low-income-assistance-programs/

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 181

181. Has the Company sold any utility property since the effective date for rates in the last rate case? If so, please describe the transaction and provide any gain from the property sale and the account in which it was recorded.

Response:
There have been no sales of utility property since the effective date of the last rate case.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 182

182. Please provide a listing of all property sales, including the sales price, net book, net gain, date of sale, and brief description of property sold from calendar 2017 to present for any plant not located in Oregon but included in Oregon rates as a result of Cascade allocations procedures.

Response:
There has been no sale of property from 2017 through present in Washington that is allocable to Oregon.

Agency Name	Agency Primary Contact	Agency Phone	Email Address	Funding Type 1 Name	Funding Type 1 Source	Funding Type 2 Name	Funding Type 2 Source	Funding Type 3 Name	Funding Type 3 Source	Agency Weblink for Governing Rules
Community Connection of NE Oregon	Jeff Hensley	541-523-6591	jeff@ccno.org	LIHEAP	federal	CNG Oregon Low Income Bill Pay Assistance Program	PPC rate collection	CNG Winter Help	company and customer donations	https://ccno.org/energy-programs/
Neighbor Impact	Lori Scharton	541-548-2380	loris@neighborimpact.org	LIHEAP	federal	CNG Oregon Low Income Bill Pay Assistance Program	PPC rate collection	CNG Winter Help	company and customer donations	https://www.neighborimpact.org/get-help/help-with-bills/home-energy-assistance/
Klamath and Lake Community Action Services	Christine Zamora	866-665-6438, 541-882-3500	christinaz@klcas.org	LIHEAP	federal	CNG Oregon Low Income Bill Pay Assistance Program	PPC rate collection	CNG Winter Help	company and customer donations	http://www.klcas.org/energy/
Community In Action	Kris Hurd	541-889-9555	kris@communityinaction.info	LIHEAP	federal	CNG Oregon Low Income Bill Pay Assistance Program	PPC rate collection	CNG Winter Help	company and customer donations	http://www.communityinaction.info/energy-assistance/
Community Action Programs of East Central Oregon	Robin Parke	800-752-1139	rparke@capeco-works.org	LIHEAP	federal	CNG Oregon Low Income Bill Pay Assistance Program	PPC rate collection	CNG Winter Help	company and customer donations	https://www.capeco-works.org/energy.html

CASE: UG 390
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 500

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is John L. Fox. I am a Senior Financial Analyst employed in the Energy Rates, Finance, and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE, Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/501.

Q. What is the purpose of your testimony?

A. My testimony addresses utility plant and income taxes

Q. Did you prepare an exhibit for this docket?

A. Yes. In addition to my witness qualification statement, I prepared the following exhibit:

Exhibit Staff/502, Responses to Staff Data Requests

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. UTILITY PLANT

Q. What is the Company's requested increase in gross plant?

A. The Company reports total plant in service of $254.9 million as of December 31, 2019 (Base Year) and projects additional plant additions of $22.1 million in calendar year 2020 (Test Year).

Q. Please summarize the Company's filing.

A. Capital projects are discussed in several sections of the Company's direct testimony:

- CNGC/100, Kivisto/3-5

  Discusses rate case drivers. States that 70 percent of the requested increase in revenue requirement is attributable to capital projects, primarily pipeline replacement. Cites base year investment of $17 million in addition to 2020 test year projects.

- CNGC/200, Darras/1-38

  Discusses project selection and budgeting, specifics for 6 major distribution projects, blanket funded projects, and the new customer care and billing system. Discussion of specific projects includes prudence elements; need, customer benefits, alternatives considered, and timing.

- CNGC/300, Peters/10-11

  Discusses 2020 plant additions. Revenue requirement for new plant is $3.16m/4.51m = 70 percent of the total. States that case will be updated to include actual costs and projects in service as they become known. All projects to be completed prior in Dec 2020 prior to the rate effective date Feb 1, 2021.

Note: The Company stated in a workshop on June 17, 2020 that the Shevlin Park project in Bend will not be completed until 2021 and needs to be removed from the case.

- CNGC/305

  Exhibit detailing proposed 2020 plant additions of $22.1 million[1] by funding project (FP#) and FERC category (intangible, distribution, and general).

Q. What is the Oregon law requiring utility plant to be presently used before it may be included in rates?

A. ORS 757.355 requires utility plant to be presently used for providing utility service to customers. In general, the Commission has applied a “used and useful” standard requiring the property to be placed into service prior to the effective date of the rates:

> (1) Except as provided in subsection (2) of this section, a public utility may not, directly or indirectly, by any device, charge, demand, collect or receive from any customer rates that include the costs of construction, building, installation or real or personal property not presently used for providing utility service to the customer.
>
> (2) The Public Utility Commission may allow rates for a water utility that include the costs of a specific capital improvement if the water utility is required to use the additional revenues solely for the purpose of completing the capital improvement. [1979 c.3 §2; 2003 c.202 §2]

Q. Please discuss the Commissions standard of review for prudence.

---

[1] $21.4 million without Shevlin Park.

A. The purpose of the prudence review has been succinctly stated by the Commission in prior rate cases:

> [*W*]*e take this opportunity to clarify the prudence standard in ratemaking. Parties have raised questions about how the Commission applies the prudence standard, particularly with regard to the relevance of the decision-making process that a utility uses to make an investment.*
>
> *The prudence standard is traditionally used to address the proper valuation of utility investment in rate base. Any investment found to be unreasonable is deemed imprudent and subject to partial or full disallowance. An example of a modem articulation of the prudence standard is as follows:*
>
> *A prudence review must determine whether the company's actions, based on all that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. It is clear that such a determination may not properly be made on the basis of hindsight judgments, nor is it appropriate for the [commission] to merely substitute its best judgment for the judgments made by the company's managers. The company's conduct should be judged by asking whether the conduct was reasonable at the time, under all circumstances, considering that the company had to solve its problems prospectively rather than in reliance on hindsight. In effect, our responsibility is to determine how reasonable people would have performed the task that confronted the company.*
>
> *Although the Oregon courts have not expressly discussed the applicability of the prudence standard in this state, this Commission has long used the standard when examining utility investments. Through various orders, the Commission has confirmed that prudence of an investment is measured from the point of time of the utility's actions and decisions without the advantage of hindsight, that the standard does not require optimal results, and the review uses an objective standard of reasonableness.*[2]

Q. Is the information provided by the Company adequate for Staff to perform the necessary prudence review of plant additions up to the rate effective date?

[2] See *In the Matter of PacifiCorp Request for a General Rate Revision,* Docket No. UE 246, Order No. 12-493 at 25 (Dec. 20, 2012).

A. Yes. First, regarding the Commission's historical treatment of plant additions, the Company's filing is relatively simple. The Company is using a partially forecasted test year (2020), which ends prior to the rate effective date. Therefore, additions subsequent to the rate effective date are not included. Also, the company has not requested any tariff riders to include the cost of projects completed after the rate effective date.

Second, the Staff recently reviewed three of the projects at issue in this case in the Company's recent Safety Cost Recovery Mechanism (SCRM) filing.[3] These three proposed projects are phases of a multiyear effort. Previous phases of the projects have been vetted in previous rate cases. No party to the rate case or SCRM has argued that the projects are imprudent. Parties to the SCRM agreed that the projects are prudent and that costs ought to be recovered in GRC rather than a separate mechanism.

The remaining projects discussed in the Company's testimony are distribution system upgrades to accommodate growth in the Bend and Redmond areas and one IT project, the Customer Care and Billing System upgrade. As noted above, the Shevlin Park project will be delayed until 2021 and will need to be removed from the case.

Q. Please discuss the Company's safety plan.

[3] *In the Matter of Cascade Natural Gas Corp. Application for a Safety Cost Recovery Mechanism* (UM 2026), Order No. 20-015.

A. The Company's safety plan is updated annually.[4] The most recent update is *Cascade's 2020 Annual Oregon System Safety Plan* (Safety Plan) filed on September 30, 2019. Staff would like to emphasize the following projects and compare Cascade's recent updated Safety Plan to the filing in this case:

*Bend 6" High-pressure Pipe (HP) Replacement Project*

The Bend 6" HP Replacement Project is a multi-year high-pressure replacement project that began in 2017 and that Cascade anticipates completing in 2024.[5] The Safety Plan states that Phase 2 was to be completed in December 2019 and that Phase 3 was scheduled for 2020 at a cost of $1.54 million.[6] The Company is projecting the following costs in this case:

- FP-316575 MAOP; 12" HP; BEND; 5,500' PHASE 2 - $726 thousand
- FP-316576 RPL; 6" HP, BEND HP PH3 - $1.8 million

However, the Company also provides the following statement in direct testimony:

> Phase 1 is complete, and Phase 2 was originally planned for 2019, but was delayed and is now scheduled for 2020. The Company is planning additional project phases in the future, and expects to complete all phases in 2024.[7]

The Company's response to Staff Data Request No. 203 confirms that Phase 3 will not be completed in 2020 but also states that the Company

[4] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Annual Natural Gas Safety Project Plan*, Docket No. 1899.
[5] CNGC/200, Daras/10.
[6] *Cascade's 2020 Annual Oregon System Safety Plan* at 16.
[7] CNGC/200, Darras/12.

expects to incur an additional $1.6 million in 2020 to complete Phase 2, which does not appear on the list of projects in Exhibit 305.

In other words, Cascade's June 19, 2020 response to Staff's data request indicates that the $1.8 million Cascade proposes to include in rate base for the Bend 6" HP Replacement Project is overstated and should be reduced. Staff recommends offsetting these two amounts and calculates the net amount to be removed from rate base in this case as follows[8]:

$1,800,952 – 1,600,000 = $201 thousand

Bend Pipe Replacement, Phase 8, Section 2A

This project is part of a multi-year pipe replacement project. Phase 8 Construction started in October 2019 and was completed in March 2020.[9] The Company reports in testimony that the total cost of the project is $858 thousand (includes $612 thousand for mains and $112 thousand for services).[10]

The Company's response to Staff Data Request No. 207 indicates the total cost of this project is actually $629 thousand (including $462 thousand for mains and $167 thousand for services), and also states the project is in service and significant additional charges are not anticipated.

[8] Exhibit 305 includes $1.8 million that shouldn't be there but ought to have $1.6 million that isn't. Since the net is less than the filed total requested rate base increase Staff believed it is reasonable to net the two amounts. If the net were actually increasing total rate base we would limit not to exceed the filed amount of $22.1 million total. As noted above, the project have been vetted and Staff believes the investment is prudent.
[9] CNGC/200, Darras/11.
[10] CNGC/200, Darras/28.

Accordingly, Staff recommends removing the difference between what is reported in testimony and the actual costs reported in discovery from rate base in this case as follows:

$858,228 – 629,368 = $229 thousand

Staff also notes that the 2020 Safety Plan anticipated Phase 9 would occur in 2020 but it has apparently been delayed.[11]

Madras Phase 3

This is the final phase of a multi-year high pressure pipeline replacement project that began in 2017.[12] The Company reports two different figures in testimony for this project, $1.950 million[13] and $2.066 million.[14] Furthermore, the Company's response to Staff Data Request No. 210 indicates the current estimated cost of the project is $2.022 million. This project appears to be occurring entirely within 2020. As the anticipated in-service date is November 2020, the variances between the figures presented are reasonable and Staff is not recommending an adjustment for the project at this time.

Q. Are there other projects in the safety plan that are not discussed specifically in the Company's direct testimony?

A. Yes, there are two.

- Baker City Bridge Crossing - planned completion Oct 2019.

[11] *Cascade's 2020 Annual Oregon System Safety Plan* at 16.
[12] CNGC/200, Darras/12.
[13] CNGC/200, Darras/36.
[14] Exhibit 305.

- Milton Freewater Canal Crossing – planned for 2020, cost $200 thousand.

The Company's response to Staff Data Request No. 202 indicates the Baker City project was completed in 2019 as planned at a cost of $391 thousand. Staff notes the cost of this project was previously estimated at $284 thousand.[15] Staff recommends the Commission consider the higher amount to be prudently incurred. In Staff's view, the unusually large variance of $110 thousand is due to the fact the Company's projections underlying the SCRM request were not reasonably accurate.

The Milton Freewater project is included in Exhibit 305 at a projected cost of $189 thousand, which is less than the previously projected cost of $199 thousand.[16]

Q. What are Staff's thoughts regarding the prudence of the safety plan projects presented for cost recovery in this case?

A. Staff and intervenors have previously expended a significant amount of effort studying these projects and the underlying Distribution Integrity Management Program (DIMP) plan[17] In Staff's view, the projects are generally well supported ought to be approved.

Q. Please discuss the Ponderosa and Redmond projects.

---

[15] See In the Matter of CASCADE NATURAL GAS CORPORATION*, Application for Approval of a Safety Cost Recovery Mechanism, Docket No. UM 2026, Exhibit CNGC/101, Privratsky-Parvinen/4.
[16] *Id.*
[17] UM 2026, Exhibit CNGC/102

A. In Staff's view, these projects are also well supported in testimony and ought to be approved.

Q. Did Staff inquire as to whether any of the growth projects could be delayed due to COVID-19?

A. Yes. The Company's responded as follows:

> Both the Bend and Redmond projects were identified as necessary prior to the anticipated growth in both areas due to lower capacity and reduced pressures in the outlying areas of both towns occurring during peak use and cold weather events. In order to delay the proposed projects in Bend would require approximately a 33% reduction in proposed loading (about 400 fewer new homes), however based on proposed development applications with the City of Bend, it does not appear that construction of these new homes has slowed in 2020. In order to delay the proposed project in Redmond would require approximately an 80% reduction in proposed load. Due to the southern location of the proposed load in Redmond is what is impacting the system since there is no high pressure or regulation in the southern Redmond system and there is a growing commercial/industrial area in this location.[18]

Q. As previously noted, the Company has indicated that it will remove the cost of the Shevlin Park project in rebuttal, are there any collateral issues?

A. Yes, the Company's response to Staff Data Request No. 204 indicates the project has been postponed until 2021. The Company's testimony indicates that there is 4000 feet of 6 inch main installed and "placed on nitrogen" in 2012 and the Shevlin Park project is necessary to "gas up" this section.[19]

Q. What is Staff's position regarding the section "placed on nitrogen"?

[18] Cascade response to Staff Data Request No. 211.
[19] CNGC/200, Darras/14-15.

A. Staff's position is the section is not used and useful providing service to Oregon customers and ought to be excluded from rate base in this case.

Q. Has the Company provided the cost of the section placed on nitrogen?

A. No. However, now that the Shevlin Park project is delayed and the 2012 section will not be "gassed up" prior to the rate effective date in this case, the Company ought to elaborate on the 2012 section in rebuttal testimony and state whether the cost has been included in Oregon rate base since 2012. Additionally, Staff has not yet issued further data requests but will do so.

Q. Are there any other segments of the Oregon system that are currently unused and "placed on nitrogen"?

A. No.[20]

Q. Is there additional information regarding the Bend 2" Pipe Replacement Project that Staff would like to bring to the Commission's attention?

A. Yes. The Company states that 107,000 feet of mains and services have been replaced and 55,000 feet are remaining.[21] The Company's response to Staff Data Request No. 208 indicates that the actual and anticipated cost for the 107,000 feet of mains and services already installed is $16 million and that Cascade anticipates costs between $16 and $17 million to install the remaining 55,000 feet. Staff would note this implies the per-foot cost for the

[20] Staff Data Request No. 205.
[21] CNGC/200, Darras/27.

remaining part of the project is approximately double what has been installed so far.

Q. Returning to Exhibit 305, what is Staff's analysis regarding the projects not specifically discussed in testimony?

A. Exhibit 305 lists distribution projects totaling $20.4 million for 2020. Staff notes that the projects discussed in testimony are only 35 percent of this total.

Project Value (000's)	Testimony Projects	
	Ongoing	New
Bend 6" HP – Phase 2 and 3	$ 2,527	
Shevlin Park Project		772
Ponderosa Reinforcement Project		236
Bend 2" Pipe Replacement Project – Phase 8 Section 2	209	
Redmond Project		1,295
Madras Phase 3	2,066	
	$ 4,802	$ 2,303

As stated in Company testimony, most of the remaining $13 million is blanket funding projects.[22] The testimony provides little detail beyond overarching purposes and how budgets are determined. Staff summarizes as follows:

[22] CNGC/200, Darras/36-37

Project Value (000's)	Growth	Relocate Replace	Other
Mains	$ 643	$ 16	
Regulator Stations		8	
Services		39	
Industrial Meters / Regulators	26	2	
Other Meters / Regulators			1,391
Cathodic Protection			275
District Projects:			
Eastern Oregon			
Mains	43	153	
Services	147	75	
Pendleton			
Mains	281	153	
Services	659	75	
Central Oregon			
Mains	1,242	153	
Services	2,539	75	
HPSS Replacements		772	
Regulator Stations	594	188	
System Safety and Integrity			
Mains		1,718	
Services		1,480	
	$ 6,174	$ 4,906	$ 1,667

The remaining $542 thousand are smaller discrete projects:

FP-316432 RP; 2" BRIDGE XING, MILTON FREEWATE	$189,447
FP-316479 Bend River Mall Main RPL Bend	10,605
FP-318684 RF-Umat-2" River Crossing	137,984
FP-318770 RF-REDM-R-VETERANS WAY-2" STD	130,658
FP-319249 Westgate Phase 1,2,3,4 NW MN Bend	73,130
	$541,824

Q. What are HPSS Replacements?

A. The Company provided the following:

> HPSS" stands for "High Pressure Service Set" and is defined as a regulating facility (located remotely or at a meter set) serving up to two (2) service lines, designed for reducing high pressures (61 psig or greater) to distribution pressure (60 psig or less), and is connected to a CNG owned high pressure distribution or transmission pipeline. In addition, HPSS's typically serve

customers that are usually rural, not near the distribution system within a city.[23]

Q. What are Staff's thoughts regarding the projected distribution projects?

A. The district distribution growth projects are roughly similar to the customer counts underlying the 2018 IRP and the relocate/replace budgets are evenly split between districts. This seems reasonable.

Regarding the System Safety and Integrity projects ($1,718 and $1.480 million above), the annual Safety Plan lists "significant" capital projects separately which are as low as $200 thousand for the Milton Freewater canal crossing.[24] Reading the Safety Plan, it is not clear to Staff what is being purchased with this funding although logically it would be projects less than $200 thousand. The annual safety plan could be improved by describing what work is being accomplished with this funding stream.

Finally, it is unclear to Staff why the Baker City and Milton Freewater canal crossings would rise to the level of being listed separately in the Safety Plan and included in the recent SCRM request whereas the Umatilla River crossing did not.

Q. Exhibit 305 also includes $626 thousand and $1.1 million for projected intangible plant and general plant additions, respectively. What are Staff's thoughts?

[23] Via e-mail July 7, 2020.
[24] *Cascade's 2020 Annual Oregon System Safety Plan* at 16.

A. The Company provided historical project level for detail for 2015-19 in response to Staff Data Request No. 201.[25] In Staff's opinion, the 2020 general and intangible plant additions are reasonable with respect to this historical information and Staff is not proposing adjustments.

Regarding the upgrade to Oracle's Customer Care and Billing (CC&B) v2.4 discussed in Cascade's testimony,[26] Staff notes that there were $570 thousand of CC&B costs allocated to Oregon in 2015 and an upgrade to version 2.4 occurred in 2017 resulting in a charge of $66 thousand to Oregon. The Company's explanation in testimony of the plan to upgrade to v2.6 and the additional cost of $255 thousand in the current case also appears to be reasonable with respect to this historical information.[27] Staff recommend this project be approved.

Q. Please summarize Staff's proposed adjustments.

A. Staff recommends a reduction in Total Plant in Service from $277.052 million in the filed case[28] to $275.850 million comprised of the following adjustments:

- A reduction of ($772) thousand to remove the cost of the Shevlin Park project.
- A reduction of ($201) thousand to remove a portion of the cost of the Bend 6" HP project based on the delay of phase 3 and updated cost figures for phase 2 provided by the Company.

[25] OPUC-201.xlsx
[26] CNGC/200, Darras/38.
[27] CNGC/200 Darras/38.

[28] CNGC/301r, Peters/1.

- A reduction of ($229) thousand to reflect a lower than projected final cost for the Bend Pipe Replacement, phase 8, section 2.

Staff also proposes to remove the 4000 feet of 6” future HP steel main installed in 2012 and associated with the Shevlin Park project that will not be used and useful at the rate effective date of this case. Cost is still to be determined.

ISSUE 2. INCOME TAXES

Q. Please summarize the Company's filing.

A. The Company provides limited discussion of income taxes in its direct testimony:

- CNGC/300, Peters/6-8

  Mentions taxes in discussion of the conversion factor, interest coordination adjustment, and 2020 plant additions.
- CNGC/301r, Peters/1 (filed June 19, 2020)

  Revenue requirement calculations showing a test year state and federal tax expense of $1.469 million comprised of the following:
  - Base year tax expense $191 thousand
  - Additional taxes resulting from proposed adjustments to base year results $89 thousand.
  - Gross up of requested revenue increase $1.188 million.
- CNGC/304, Peters/1

  Itemization of proposed adjustments to base year results, which includes the $89 thousand of taxes in Exhibit 301r.
- CNGC/401, Myhrum/1-4

  Revenue proof showing the amounts refunded to ratepayers in the base year for unprotected excess deferred income taxes (unprotected EDIT) and interim tax benefits resulting from the 2017 reduction in federal tax rates from 35 percent to 21 percent (refund tariffs 198 and 199, respectively).

Q. What are the requirements of Oregon law regarding the inclusion of income taxes in utility rates?

A. Income taxes in utility rates are subject to the requirements of ORS 757.269.

> **757.269 Setting of rates based upon income taxes paid by utility; limitation on use of tax information; rules.** (1) When establishing schedules and rates under ORS 757.210 for an electricity or natural gas utility, the Public Utility Commission shall act to balance the interests of the customers of the utility and the utility's investors by setting fair, just and reasonable rates that include amounts for income taxes. Subject to subsections (2) and (3) of this section, amounts for income taxes included in rates are fair, just and reasonable if the rates include current and deferred income taxes and other related tax items that are based on estimated revenues derived from the regulated operations of the utility.
>
> (2) During ratemaking proceedings conducted pursuant to ORS 757.210, the Public Utility Commission must ensure that the income taxes included in the electricity or natural gas utility's rates:
>
> (a) Include all expected current and deferred tax balances and tax credits made in providing regulated utility service to the utility's customers in this state;
>
> (b) Include only the current provision for deferred income taxes, accumulated deferred income taxes and other tax related items that are based on revenues, expenses and the rate base included in rates and on the same basis as included in rates;
>
> (c) Reflect all known changes to tax and accounting laws or policy that would affect the calculated taxes;
>
> (d) Are reduced by tax benefits generated by expenditures made in providing regulated utility service to the utility's customers in this state, regardless of whether the taxes are paid by the utility or an affiliated group;
>
> (e) Contain all adjustments necessary in order to ensure compliance with the normalization requirements of federal tax law; and
>
> (f) Reflect other considerations the commission deems relevant to protect the public interest.
>
> (3) During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes as part of an affiliated group, the Public Utility Commission may adjust the utility's estimated income tax expense based upon:

> (a) Whether the utility's affiliated group has a history of paying federal or state income taxes that are less than the federal or state income taxes the utility would pay to units of government if it were an Oregon-only regulated utility operation;
>
> (b) Whether the corporate structure under which the utility is held affects the taxes paid by the affiliated group; or
>
> (c) Any other considerations the commission deems relevant to protect the public interest.
>
> (4)(a) Because tax information of unregulated nonutility business in an electricity or natural gas utility's affiliated group is commercially sensitive, and public disclosure of such information could provide a commercial advantage to other businesses, the Public Utility Commission may not use the tax information obtained under this section for any purpose other than those described in this section, in ORS 757.511 and as necessary for the implementation and administration of this section and ORS 757.511.
>
> (b) The commission shall adopt rules to implement paragraph (a) of this subsection that:
>
> (A) Identify all documents and tax information that an electricity or natural gas utility must file in its initial filing in a proceeding to change rates that include amounts for income taxes, recognizing that any party may object to providing such documents on the grounds that they are not relevant; and
>
> (B) Determine the procedures under which intervenors in such proceedings may obtain and use documents and tax information to fully participate in the proceeding.
>
> (5) As used in this section, "affiliated group" means a group of corporations of which the public utility is a member and that files a consolidated federal income tax return. [2011 c.137 §1]

Q. Please summarize Staff's review of income taxes in this case.

A. Staff issued a number of data requests and analyzed the Company's responses.[29] Staff's examination and discovery included confirming the federal and state tax rates, calculation of current and deferred income tax expense, application of net operating losses (NOL) tax credits, ongoing amortization of

[29] Cascade's Response to Staff Data Request Nos. 212 through 216.

excess deferred income taxes (EDIT) resulting from the 2017 tax act, and CARES act benefits (COVID-19).

Q. Is Staff proposing adjustments related to income taxes other than those necessary to finalize the Company's revenue requirement?

A. Yes, Staff proposes adjustments to reduce income tax expense for protected EDIT benefits, remove the amounts collected in 2019 for Schedules 198 and 199 from other operating revenues, and include the Corporate Activity Tax (CAT) in base rates. The Company's filing does not include the new Oregon CAT in the base rate revenue requirement.

Q. Would Staff please provide the main impact of the 2017 Tax Act in general on regulated public energy utilities?

A. Yes. The three major impacts for regulated public energy utilities are:

1) The change in the corporate tax rate lowers the tax expense included in cost of service.
2) The change in the tax rate requires the recalculation of the Accumulated Deferred Income Tax (ADIT) balance, which may give rise to Excess Deferred Income Tax (EDIT).
3) The elimination of bonus depreciation after September 27, 2017.

Referring to item 2 on the list above, the largest component of ADIT requiring re-measurement in rate base for public utilities is accelerated depreciation on plant for tax purposes versus straight-line for book purposes. As a result of the tax rate change, a portion of the taxes collected by utilities from customers in rates is no longer due to the federal government in a future period. Since accelerated depreciation is subject to normalization rules, the TCJA mandates certain methodologies for the timing of the return or flow-through of the excess deferred income taxes (EDIT) to customers. The TCJA has eliminated or restructured other tax deductions that will also affect the ADIT balance. However, while these deductions may give rise to EDIT, they are not subject to normalization rules and are not subject to the TCJA methodologies for flowing the excess tax back to customers.

Q. Can you clarify the various terms used to describe EDIT?

A. Yes. EDIT falls into two broad categories. First, amounts arising from depreciation of utility plant are subject to IRS rules that limit how the TCJA benefits can be returned to rate payers. This can be referred to as “plant related”, “ARAM,”[30] or “protected” EDIT. The term “ARAM” is derived from one of the two allowable methods to calculate the return limit. The term “protected” also means the EDIT can be returned no faster than IRS rules allow.

The second category is defined by exclusion ~ EDIT arising from the revaluation of deferred tax liabilities not subject to IRS return limits. These items can be referred to as “non-plant related” or unprotected. IRS rules allow these benefits to be returned using any reasonable method.

Q. How were the TCJA benefits resolved in the Company’s previous rate case UG 347?

[30] The two allowable methods for calculating the return of protected EDIT to ratepayers are the Average Rate Assumption Method (ARAM) and the Reverse South Georgia Method (RSGM).

A. The parties stipulated to including annual protected EDIT in the amount of $382,556 as a reduction in base rates, and returning $355,420 of unprotected EDIT (before gross-up) to ratepayers annually (Schedule 198). The ratemaking treatment Interim period benefits for reductions in taxes that occurred after the TCJA but before new rates became were resolved in a separate docket.[31] (Schedule 199).

Q. Are the ongoing protected EDIT benefits included in base rates in this proceeding?

A. No, the Company's response to Staff Data Request No. 214 indicates that they are not and states the following:

> Line 17 of Exhibit 301 is $191,406. That value represents the Oregon Share of Current and Deferred, Federal and Oregon State Income Taxes offset by the Oregon Share of Investment Tax Credits. No EDIT's (Protected or Unprotected) are included in that value.

Annual protected EDIT must be included in this case also and Staff proposes return of the same annual amount, $382,556.

Q. What is the revenue requirement effect of this adjustment?

A. Because the proposed adjustment is a reduction in base rate tax expense it will be grossed up as part of the requested revenue increase.

Q. How did Staff evaluate the reasonableness of this amount in the UG 347 docket?

[31] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Application for Deferral of 2018 Net Benefits Associated with the US Tax Cuts and Jobs Act,* Docket No. UM 1927, Order No. 19-302, Sep 19, 2019.

A. Staff stated the following in testimony:

> The Company is using the ARAM method and the underlying calculations are highly detailed and somewhat complex. However, a useful reasonableness test is to compare the ARAM return to the composite useful life reported in the Company's most recent depreciation docket on a percentage basis.
>
> - ARAM return (system wide) = $1,699,492 / 41,264,063 = 4.12%
> - Composite useful life[32] = 100 / 32.1 years = 3.12%
>
> The system wide ARAM amount is allocated to Oregon proportional to Oregon's share of plant assets. Staff considers both the percentage rate of return and method to allocate Oregon benefits to be reasonable.[33]

Q. Turning to unprotected EDIT and the 2018 interim tax benefits please explain how these are reflected in this case.

A. First, the unprotected EDIT is grossed up because it is being returned on a separate tariff outside of base rates as per the figures provided in response to Staff Data Request No. No. 214. Second, the unprotected EDIT and interim tax benefits are being returned through Schedules198 and 199, respectively, and therefore should not affect base rates in this case. However, the two tariffs are affecting base rates indirectly because they were not adjusted out of other operating revenues.

[32] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Depreciation Study on All Gas Plant as of December 31, 2013*, Docket No. UM 1727, Order No. 15-315, Appendix B, page 1.
[33] UG 347 Staff/200, Fox/8-9

Q. Please elaborate on how Schedules 198 and 199 are affecting base rates and Staff's proposed adjustment.

A. Referring to Exhibit 301r, line 3, the Company reports negative other operating revenues of ($30,415), which carry through unadjusted to the proposed revenue requirement. Referring to Exhibit 401, unprotected EDIT and interim tax benefits are included in the revenue reconciliation for each rate class, which ties to the revenue sub-total of $67,070,587 found on Exhibit 301r, line 4. Staff review of the underlying work paper[34] indicates that unprotected EDIT and interim tax benefits included in other operating revenues are ($158,007) and ($230,520), respectively.

Removing these two amounts would increase other operating revenues as follows:

($30,415) – (158,007) – (230,520) = $358,112.

By failing to remove the effect of these tariffs, the Company's filing effectively negates the Schedule 198 and 199 refunds by decreasing other revenues and increasing the base rate revenue requirement. These amounts must be removed. Staff proposes a corresponding increase in other operating revenues of $388,527.

Q. What is the CAT and how is it reflected in the Company's filing in this case?

A. The CAT was enacted by the 2019 Legislative Assembly and imposes a tax of $250 plus 0.57 percent of taxable commercial activity in excess of $1 million

[34] IDM-WP1 (Proof of Rev).xlsb

each year. Cascade estimates the amount of the CAT for 2020 will be $200 thousand.[35]

The CAT is not included in the Company's rate case filing. There is no mention of the CAT in the customary testimony regarding taxes in the revenue requirement and it does not appear to be included in the Company's work papers.

Q. Has the Commission acted upon any other dockets regarding the CAT?

A. Yes. The six investor owned utilities in Oregon have filed deferral applications for the CAT.[36] PacifiCorp's and PGE's applications included proposed tariffs to recover deferred amounts. The Commission has approved both the deferral applications and tariffs with an automatic adjustment clause to amortize the deferred costs that will be terminated once the CAT is rolled into base rates.[37]

PacifiCorp has subsequently filed a request for a general rate revision (UE 374) which, like Cascade's request in this case, does not include the CAT.

Q. What does Staff recommend regarding the CAT in this case?

A. Staff has a strong preference for inclusion of the CAT in base rates as soon as possible and intervenors have indicated that point of view also. Staff recognizes that many uncertainties remain regarding the CAT. However, the

[35] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Application for Deferred Accounting of Costs Associated with the Oregon Corporate Tax Activity*, Docket No. UM 2052 filed Dec 31, 2019, at 2.

[36] PacifiCorp UM 2036, PGE UM 2037, Idaho Power UM 2035, Avista Utilities UM 2042, and NW Natural UM 2044.

[37] Order Nos. 20-028 and 20-029.

analysis in this case ought to center around whether the CAT is reasonably able to be estimated in the revenue requirement rather than an ongoing deferral mechanism.

Cascade is required to pay the CAT quarterly (e.g. $50 thousand per quarter) on an estimated basis even though the rules surrounding the tax remain unsettled and the Oregon Department of Revenue continues to issue regulations specifying the particulars of how the tax is to be calculated. Staff recommends including the $200 thousand CAT estimate in the base rate revenue requirement.

Q. Please summarize Staff's proposed adjustments.

A. Staff recommends the following adjustments:

- A reduction of ($383) thousand to State and Federal Income Taxes necessary to include the ongoing benefit of protected EDIT amortization.
- An increase in Other Operating Revenues of $389 thousand to remove the base year amounts for Schedules 198 and 199, which are improperly reducing other revenues and increasing the base rate revenue requirement.
- An increase of $200 thousand in Taxes Other Than Income to include the new Oregon Corporate Activity Tax in base rates.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 390
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 501

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME:	John L. Fox
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Financial Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	I hold a Bachelor of Science degree in Business Administration / Accounting from the University of Oregon (1989). I also completed the Certificate in Public Management program at Willamette University (2010). I have been licensed as a Certified Public Accountant in Oregon since 1991. Maintaining active status has required a minimum of 80 hours continuing professional education every two years.
EXPERIENCE:	From 1989 to 1999 I was in general practice with several CPA firms in Southern Oregon and the Mid-Willamette Valley. My tax experience includes individuals, trusts and estates, qualified retirement plans, and extensive corporate, partnership, and LLC work. Accounting experience during this time includes client write up, compilation and review, and significant audit and attest work. I have been employed in the executive branch of Oregon state government since 1999. My experience prior to joining the Commission staff includes 3 years as a cost accountant, 11 years as a senior budget analyst, and 4 years in an oversight role as a budget team lead. I have extensive experience in capital construction and financing, complex cost modeling, rate development, fiscal projections, expenditure analysis, and cost control for programs with biennial revenues between $100 million and $300 million.
PRIOR DOCKETS:	I have provided testimony as a Staff witness in the following OPUC proceedings; UE 335, UE 374 (pending), UG 344, UG 347, UG 366, UG 388 (pending), UG 389 (pending), UG 390 (pending), UM 1992, UM 2004, UM 2026.

CASE: UG 390
WITNESS: JOHN L. FOX

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 502

Exhibits in Support
Of Opening Testimony

July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 201

Date prepared: June 19, 2020

Preparer: Jordan Small

Contact: Chris Mickelson

Telephone: (509)-734-4549

201. Please append Exhibit 305 to include actual plant additions for 2015-2019 in a single excel worksheet at the same level of detail (function, funding project number, description, FERC Acct, System wide and Oregon). For blanket funding projects, please indicate which of the three categories to which they belong (CNGC/200, Darras/36).

Response:

Please see "OPUC-201" Excel file for requested information.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 202

Date prepared: June 19, 2020

Preparer: Linda Offerdahl

Contact: Chris Mickelson

Telephone: (509)-734-4549

202. For non-blanket funding projects over $150,000 in 2018 and 2019 only, please provide a detailed narrative description for each project describing what was purchased, how the project specifically benefits Oregon ratepayers, why the investment was necessary, what other alternatives were considered, and what would occur if the investment had not been made.

Response:

The below table shows the projects in 2018 and 2019 that meet the criteria requested above. In the last column indicates the attachment corresponding to the project that provides the narrative description, what was purchased, project benefits, why the project was necessary, what alternatives were considered, and what would occur if the investment had not been made.

fp_number	2018	2019	Attachment Detail
FP-200689 - RPL; 6" HP, BEND HP PH1	$ 1,181,991.42	$ 544,556.51	OPUC-202-A
FP-303142 - PENDLETON PIPE REPLACEMENT-PH1	$ 579,881.75	$ -	OPUC-202-B
FP-306989 - UMATILLA 2" REINFORCEMENT	$ 13,366.51	$ 512,780.98	OPUC-202-C
FP-306997 - RPL; 4" HP, MADRAS PH1	$ 2,005,951.42	$ 15,679.58	OPUC-202-D
FP-316401 - RP; 2,4" BRIDGE XINGS, BAKER CITY	$ -	$ 391,062.86	OPUC-202-E
FP-316573 - RPL; 4" HP, MADRAS PH2	$ -	$ 1,819,895.11	OPUC-202-E
FP-316697 - RP; 4" ST; BEND; 2,500' PH 7 SEC 1	$ 1,022,234.98	$ -	OPUC-202-F
FP-317235 - 2" ST; BEND; 750' PH 7 SEC 2	$ 1,051,043.67	$ -	OPUC-202-E
FP-317349 - RP; 8" ST; PENDLETON; 1960' PH 2	$ 996,771.24	$ 1,022,489.33	OPUC-202-B
FP-317393 - RP; 1/2" SL; PEND; PH 2 SERVICES	$ 585,433.80	$ -	OPUC-202-B
FP-317505 - RP; 2" ST; BEND; 4,610' PH 8 SEC 1	$ -	$ 1,297,568.18	OPUC-202-E
FP-317523 - RP; 3/4" SL; BEND; PH 8 SEC 1 SERV	$ -	$ 272,380.01	OPUC-202-E

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 203

Date prepared: June 19, 2020

Preparer: Ryan Privratsky

Contact: Chris Mickelson

Telephone: (509)-734-4549

203. Regarding Bend 6” HP – Phase 2,
   a. Please provide a reconciliation of the differences between the 2020 project cost (CNGC/200, Darras/14) and the phase 2 and phase 3 figures in Exhibit 305.
   b. Please confirm that phase 3 will actually occur in 2020 as it shows as 2021 in figure 2 on CNGC/200, Darras/13.
   c. Please provide the estimated in service date for phase 3.
   d. Please provide the currently anticipated costs of future phases 4 through 6 as shown in figure 2 on CNGC/200, Darras/13.

Response:

a. CNGC/200, Darras/14 = $2,064,240
   Exhibit 305 = $726,189.91 (FP-316575 MAOP; 12" HP; BEND; 5,500' PHASE 2)
   Exhibit 305 = $1,800,952.04 (FP-316576 RPL; 6" HP, BEND HP PH3)

   The total of $726,189.91 from Exhibit 305 was the total actual costs for the work that was completed in 2019 before construction was shut down by the City of Bend for winter. CNGC was anticipating having the project completed in 2019, but easement and project delays prevented that from occurring. Project actual costs, in 2020, through May is $750,873. CNGC is estimating another $1.6 million in project costs to complete Phase 2 in 2020. Estimated in-service date for Phase 2 is August, with an overall estimated project cost of $3.1 million. CNGC has seen significant increase in construction costs in 2020 contributed to extra depth requirements, pipe removal, and restoration requirements being required by the City of Bend. CNGC intends to possibly start preliminary design work on Phase 3 during the 4th quarter of 2020, but costs are estimated to be under $50,000 in 2020, with anticipated completion of Phase 3 in 2021.

b. Phase 3 of the Bend 6” HP replacement will not occur in 2020. Permitting and easement delays in 2019 prevented Phase 2 from be completed in 2019. CNGC intends to complete Phase 2 in 2020 and Phase 3 in 2021.

c. Currently CNGC estimates Phase 3 to be in-service near the end of 2021.

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d. CNGC is estimating future phases of the Bend 6” HP replacement to be around $1.8 - $2.0 million per year/phase.

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Request No. 204

Date prepared: June 22, 2020

Preparer: Linda Offerdahl

Contact: Chris Mickelson

Telephone: (509)-734-4549

204. Regarding the Shevlin Park Project,
  a. Please split the project costs in the table on CNGC/200, Darras/20 by year.
    i. Please provide a reconciliation to Exhibit 305 if the 2020 figures are different.
  b. Regarding the 4000' of main discussed on CNGC/200, Darras/20,
    i. Please provide a narrative explanation of what being "placed on nitrogen" entails.
    ii. Please identify any dockets or Commission orders where this section of main was discussed.
    iii. Please provide a narrative explanation of any period of time that this line was presently used providing utility service to customers since 2012.
    iv. Please provide the total installed cost of the main.
    v. Please provide a narrative discussion of the anticipated expansion needs in 2012 and how changes in economic conditions have affected when this section of main is placed into use.
  c. Please provide a narrative explanation of the additional infrastructure investment that will be needed to serve the "1,000 homes in 2-4 years" cited in Figure 3.
  d. Please provide a narrative explanation of the incremental costs to the Company of bypass operations discussed on CNGC/200, Darras/18 and a list of bypass events that occurred in the last 3 years.
  e. Please quantify the anticipated "efficiencies and cost savings" discussed on CNGC/200, Darras/18.
  f. Please provide a narrative explanation of how the Company participated in the planning and development agreements cited in the footnote on page CNGC/200, Darras/15 including why the plans were not known in time for the 2018 IRP as noted on CNGC/200, Darras/19.

Response:

The Shevlin Park Project has been postponed to 2021 due to COVID-19 impacts. The Company will remove this project from the UG390 request in a rebuttal filing.

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Request No. 205

Date prepared: June 17, 2020

Preparer: Linda Offerdahl

Contact: Chris Mickelson

Telephone: (509)-734-4549

205. Please identify any other segments of the Oregon system that are currently unused and "placed on nitrogen".

Response:

There are no other segments of the Oregon system that are unused or "placed on nitrogen".

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Request No. 206

Date prepared: June 17, 2020

Preparer: Linda Offerdahl

Contact: Chris Mickelson

Telephone: (509)-734-4549

206. Regarding the Ponderosa Reinforcement Project,
   a. Please provide a reconciliation of the differences between the total project cost in the table on CNGC/200, Darras/25 and the project cost in Exhibit 305.
   b. Please provide a narrative explanation of the incremental costs to the Company of bypass operations discussed on CNGC/200, Darras/22 and a list of bypass events that occurred in the last 3 years.

Response:

Difference in cost estimate from Darras/25 ($232,030.20) and estimate in Exhibit 305 (FP#318741, $235,682) is due to lower corporate overhead rate used in Darras/25 estimate.

The incremental costs to the Company of bypass operations is typically $3,000 per event. Bypass operations most often occur during early morning hours (the coldest and highest usage part of the day) resulting in a minimum of two-four service mechanics, plus equipment, responding on overtime to perform the operations and monitor pressures at various stations in the distribution system. The Bend District has performed one bypass operation on the Bend Distribution system in the past three years during a cold weather event in February 2018. Since then, and prior to this bypass operation, the district personnel have been called out, due to low pressures experienced in early winter mornings, averaging 6 times per winter season, to monitor closely the outlet pressures at regulator stations and preparing to bypass if necessary.

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Request No. 207

Date prepared: June 19, 2020

Preparer: Ryan Privratsky

Contact: Chris Mickelson

Telephone: (509)-734-4549

207. Regarding the Bend 2" Pipe Replacement Project – Phase 8 Section 2 A,
   a. Please provide a reconciliation of the differences between the estimate costs of the project on CNGC/200, Darras/28 and the project cost in Exhibit 305.

Response:

a. CNGC/200, Darras/28 = Phase 8 Section 2 A Mains Replacement - $612,119
   CNGC/200, Darras/28 = Phase 8 Section 2 A Service Replacement - $246,109

   Exhibit 305 = $155,849.25 (FP-319230 RP; 2" ST; BEND; 2,528' PH 8 SEC 2)
   Exhibit 305 = 52,653.41 (FP-319231 RP; 3/4" SL; BEND; PH 8 SEC 2 A SER)

   <u>Current Total Charges</u>

   FP-319230 RP; 2" ST; BEND; 2,528' PH 8 SEC 2 = $462,360.32
   FP-319231 RP; 3/4" SL; BEND; PH 8 SEC 2 A SER = $167,007.60

   Project is in-service, CNGC isn't currently anticipating any additional significant charges to this project.

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Request No. 208

Date prepared: June 19, 2020

Preparer: Ryan Privratsky

Contact: Chris Mickelson

Telephone: (509)-734-4549

208. Regarding the Bend 2” Pipe Replacement Project as a whole,
    a. Please provide the currently anticipated costs of future phases 8 through 12 as shown in figure 9 on CNGC/200, Darras/26.
    b. Please provide the total installed cost of the 107,000’ of mains and services referenced on CNGC/200, Darras/27 and the anticipated installed cost of the remaining 55,000’.

Response:

a. CNGC anticipates spending approximately $3.2 – $3.4 million over the next 4 – 5 years to complete the replacement of the remaining high-risk pipe in Bend. The size of each year’s replacement project is dependent on multiple variables, including, contractor costs, restoration requirements, City of Bend permitting requirements, etc.

b. The total installed costs of the pipe replaced during the Bend Pipe Replacement project since 2012 is approximately $16.

   Anticipated installed cost to replace the remaining high-risk pipe in Bend, is estimated to be around $16 - $17 million.

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Request No. 209

Date prepared: June 16, 2020

Preparer: Linda Offerdahl

Contact: Chris Mickelson

Telephone: (509)-734-4549

209. Regarding the Redmond Project,
    a. Please provide a reconciliation of the differences between the total estimated project cost in the table on CNGC/200, Darras/34 and the project cost in Exhibit 305.

Response:

Difference is due to the Redmond Project incorporates both the pipeline installation (FP#317586) and the regulator station installation (FP#318770). In Exhibit 305 the Redmond pipeline installation (FP#317586) is estimated as $1,295,377.66 and the Redmond regulator station (FP#318770) is estimated as $130,658.00 with a total Redmond Project estimate of $1,426,035.66. The estimate shown in Darras/34 was prior to the final negotiation for the pipeline and regulator station easement and prior to the construction bids coming in, which both came in higher than originally estimated.

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Request No. 210

Date prepared: June 19, 2020

Preparer: Ryan Privratsky

Contact: Chris Mickelson

Telephone: (509)-734-4549

210. Regarding Madras Phase 3,
    a. Please provide a reconciliation of the differences between the anticipated project cost on CNGC/200, Darras/36 and the project cost in Exhibit 305.

Response:

a. CNGC/200, Darras/36 = $1,950,000
   Exhibit 305 = $2,066,432.99

   Current estimate for the Madras Phase 3 project (FP-316574) is $2,022,376.

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Request No. 211

Date prepared: June 16, 2020

Preparer: Linda Offerdahl

Contact: Chris Mickelson

Telephone: (509)-734-4549

211. Regarding anticipated growth in Bend and Redmond, taken as a whole, and the discussion of COVID impacts on CNGC/100, Kivisto/7,
    a. Please provide a narrative discussion how economic conditions would need to change for portions of the capital projects in this case to be delayed.

Response:

Both the Bend and Redmond projects were identified as necessary prior to the anticipated growth in both areas due to lower capacity and reduced pressures in the outlying areas of both towns occurring during peak use and cold weather events. In order to delay the proposed projects in Bend would require approximately a 33% reduction in proposed loading (about 400 fewer new homes), however based on proposed development applications with the City of Bend, it does not appear that construction of these new homes has slowed in 2020. In order to delay the proposed project in Redmond would require approximately an 80% reduction in proposed load. Due to the southern location of the proposed load in Redmond is what is impacting the system since there is no high pressure or regulation in the southern Redmond system and there is a growing commercial/industrial area in this location.

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Request No. 212

Date prepared: 6/23/20

Preparer: Tony Durado

Contact: Chris Mickelson

Telephone: (509)-734-4549

212. Regarding the Company's response to Staff Data Request 114,
    a. Please provide a reconciliation of the 2018 book income before tax in OPUC-114.xlsx to the net operating income reported in the 2018 results of operations Docket No. RG 36(7). (Staff calculates a variance of $1,907 using available information).

Response:

Current Year Tax Expense is calculated based on results of activity for the period and estimates of certain deductions based on anticipated year end results. The current and deferred tax expense is then booked at the close of each period.

Actual Tax Expense for a given fiscal period cannot be determined until all consolidated level Federal and State Tax returns have been filed with appropriate jurisdictions in the fall of the year after a period closes. Actual Tax Expense will contain adjustments between estimated deductions and actual results, as well as allocated portions of consolidated level deductions. Actual Tax Expense is then booked to the current year books in November as an out of period adjustment. This means that the fiscal results for 20X2, contains tax expense related to 20X2 and the True-up Tax Expense Adjustment for 20X1, while the 20X2 True-up Tax Expense Adjustment will be booked to the 20X3 books.

The response provided for DR-114 contains a book to tax reconciliation of the Operational and Non-Operational results of 2019 activity for both Washington & Oregon, without the 2018 Tax Expense True-up Adjustment.

Comparison of responses to DR-114 and 2018 ROO is problematic in that each represents different fiscal years of operation.

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Request No. 213

Date prepared: 6/23/20

Preparer: Tony Durado

Contact: Chris Mickelson

Telephone: (509)-734-4549

213. Regarding the Company's response to Staff Data Request 115,
    a. Please provide the requested information for the 2019 base year. (the responsive file OPUC-114.xlsx is for the year 2018 per the response to Staff Data Request 114).
    b. Regarding the test year,
        i. Please provide a reconciliation of the 2020 book income before tax in OPUC-115.xlsx to the test year net operating revenues in Exhibit 301.
        ii. Please provide a narrative explanation of the deferred current amount labeled "UT0391 PURCHASED GAS ADJUSTMENT *NEW*".
        iii. Please disaggregate the $432,459.93 "State and Local Current Tax" figure by jurisdiction.

Response:

Current Year Tax Expense is calculated based on results of activity for the period and estimates of certain deductions based on anticipated year end results. The current and deferred tax expense is then booked at the close of each period.

Actual Tax Expense for a given fiscal period cannot be determined until all consolidated level Federal and State Tax returns have been filed with appropriate jurisdictions in the fall of the year after a period closes. Actual Tax Expense will contain adjustments between estimated deductions and actual results, as well as allocated portions of consolidated level deductions. Actual Tax Expense is then booked to the current year books in November as an out of period adjustment. This means that the fiscal results for 20X2, contains tax expense related to 20X2 and the True-up Tax Expense Adjustment for 20X1, while the 20X2 True-up Tax Expense Adjustment will be booked to the 20X3 books.

Part a.
The response provided for DR-114 contains a book to tax reconciliation of the Operational and Non-Operational results of 2019 activity for both Washington & Oregon, without the 2018 Tax Expense True-up Adjustment.

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Part b. i.
The response provided for DR-115 contains a book to tax reconciliation of the Operational and Non-Operational results of 2020 Plan activity for both Washington & Oregon, without the 2019 Tax Expense True-up Adjustment.

Comparison of responses to DR-115 and 2019 ROO is problematic in that each represents different fiscal years of operation.

Part b. ii.
UT0391 Purchased Gas Adjustment *New* is the Deferred Tax M-1 Adjustment for WA's 3 year amortization and OR's 1 year amortization of the excess of actual natural gas costs over anticipated costs included in the 2018 rate structure.

Part b. iii.
$432,459.93 is the value for State of Oregon Income Tax Expense on 2020 Plan Oregon Operating Income. There are no Local or other State Jurisdictions included in this total.

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Request No. 214

Date prepared: Tony Durado

Preparer: 6/22/20

Contact: Chris Mickelson

Telephone: (509)-734-4549

214. Regarding amortization of protected excess deferred income taxes (EDIT),
   a. Please identify the amount of protected EDIT amortization included on line 17 of Exhibit 301.
   b. Please provide the amount of Oregon allocated EDIT amortization anticipated for each year from 2019 through 2023.

Response:

214.a.

Line 17 of Exhibit 301 is $191,406. That value represents the Oregon Share of Current and Deferred, Federal and Oregon State Income Taxes offset by the Oregon Share of Investment Tax Credits. No EDIT's (Protected or Unprotected) are included in that value.

214.b.

Period Ended	Non-Protected EDIT	Non-Protected Gross-Up	Total
12/31/19	$266,564.94	$110,183.22	$376,748.19
12/31/20	$355,419.96	$146,910.96	$502,330.92
12/31/21	$355,419.96	$146,910.96	$502,330.92
12/31/22	$355,419.96	$146,910.96	$502,330.92
12/31/23	$355,419.96	$146,910.96	$502,330.92
03/31/24	$ 88,854.99	$ 36,727.74	$125,582.73

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Request No. 215

Date prepared: 6/22/20

Preparer: Tony Durado

Contact: Chris Mickelson

Telephone: (509)-734-4549

215. Regarding the Company's response to Staff Data Request 118,
   a. Please provide a narrative description of the CC&B project.
   b. Please indicate if the credit figures in the data response are CNGC system figures or Oregon allocated.
   c. Please indicate if the $145,000 credit for 2019 is included on line 17 of Exhibit 301.

Response:

215.a.

Cascade Natural Gas Corporation, in partnership with Intermountain Gas Company and Montana-Dakota Utilities Co., selected Oracle's Utilities Customer Care and Billing (CC&B) software to replace several legacy computer information systems with one centralized system, as well as to develop and implement an application for interreacting with customers. CC&B is a complete billing and customer care application for residential, commercial, and industrial customers. The CC&B project is the implementation and customization of the CC&B software for the three utility companies. The project encompasses subsequent upgrades to CC&B, which include the integration of new and existing modules, addition of capabilities and functionality, and technical issues resolution. Software design and integration throughout the project are performed by an in-house software development team with the assistance of other utility employees and outside consultants.

215. b.

The credit figures described in response to DR-118 are for CNGC Total System, prior to any state allocation.

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215. c.

Line 17 of Exhibit 301 is $191,406. That value represents the Oregon Share of Current and Deferred, Federal and Oregon State Income Taxes offset by the Oregon Share of Investment Tax Credits.

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Due June 26, 2020

Request No. 216

Date prepared: June 15, 2020

Preparer: Maryalice Peters

Contact: Chris Mickelson

Telephone: (509)-734-4549

216. Please provide a copy of the Company's response to OPUC Request No. 1 in Docket UM 2072.

Response:

See OPUC-216 UM 2072.doc

CASE: UG 390
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 600

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Scott Gibbens. I am a senior economist employed in the Energy Rates, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/601.

Q. What is the purpose of your testimony?

A. I discuss the Company's load forecast and decoupling mechanism for the 2020 test year. I provide an overview of Staff's analysis and resulting recommendations.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. LOAD FORECAST AND SALES REVENUE

Q. Please summarize the Company's load forecasting methodology.

A. Cascade utilizes Autoregressive Integrated Moving Average (ARIMA) models for its customer and demand forecasts.[1] The two components of load, use-per-customer and number of customers, are forecasted separately – and then multiplied to obtain the load. Economic and weather variables are used as forecast drivers in the models.[2] ARIMA models work well for forecasting natural gas usage because of their ability to model data with trends and incorporate past data into the current time period forecast.

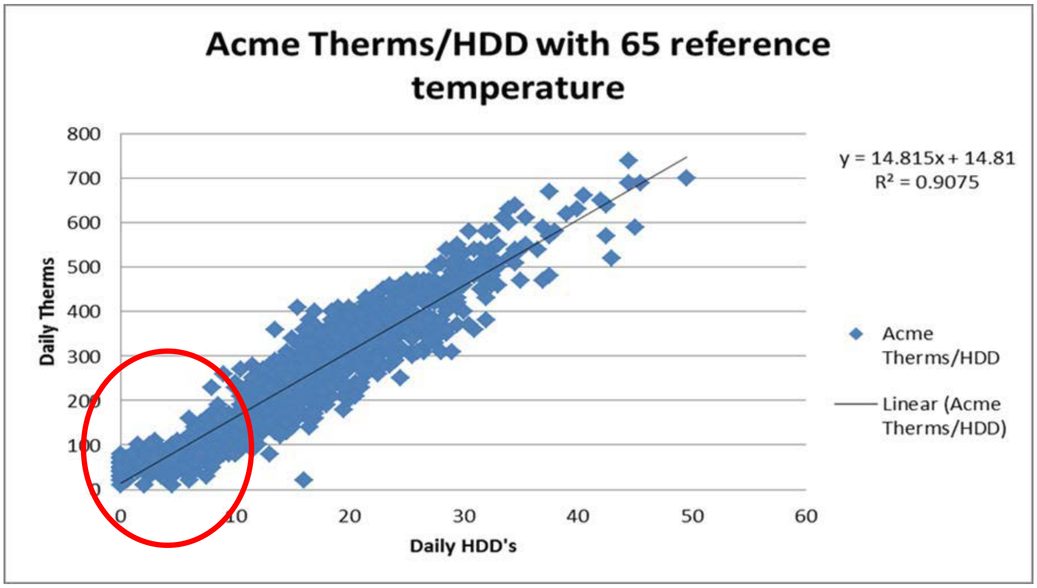
Q. Describe the Company's primary forecast driver for residential UPC?

A. Cascade uses weather as the primary forecast driver for UPC. The data itself is provided by Schneider Electric. This is a change from Cascade's previous process which utilized NOAA data. The Company states that the NOAA data was time consuming to implement due to the fact that many months/locations had missing data points. The weather is assigned to each city gate[3] based on its proximity to the closest of seven different weather stations and differentiated by class. The Company uses the most recent 30 years of weather data from the seven weather stations, three of which are in Oregon and four in Washington. The Company uses a 60 degree Fahrenheit (60 °F) HDD metric that is averaged over the thirty years to normalize the weather. The Company

[1] Staff/602, Cascade 2020 Draft IRP, Chapter 3.
[2] *Ibid.*
[3] A "city gate" is a point or measuring station at which a gas distribution company receives gas from a pipeline company or transmission system.

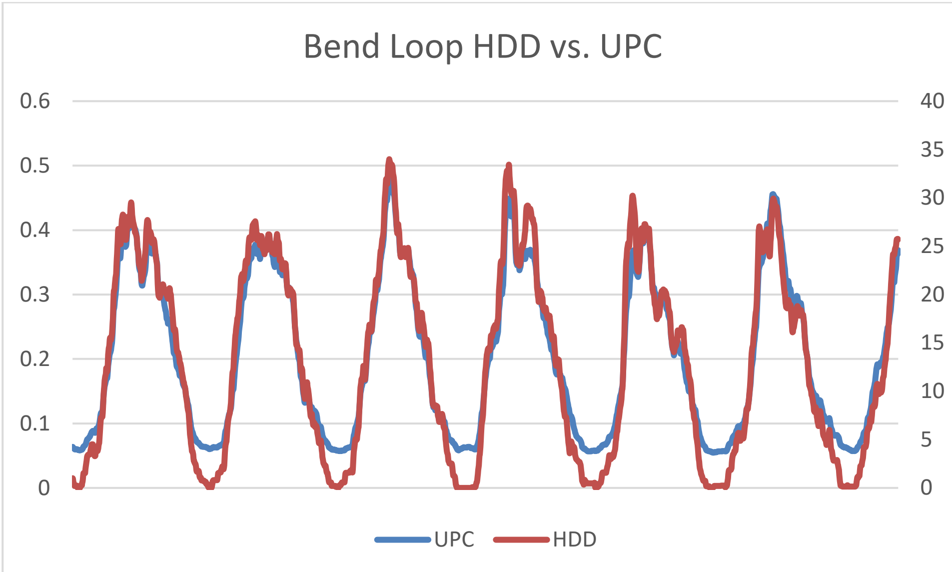
changed from a 65 °F threshold because demand becomes more responsive to weather at 60 °F. Note the relatively flat section of the blue dots in the otherwise linear relationship in the figure below shown in the red circle. This indicates that usage does not start to respond to weather until the average temperature is closer to 60 °F.

Figure 1



Weather describes a high proportion of the usages-per-customer. Figure 2 below uses the Company's data to plot Bend residential UPC versus heating degree days (HDD) over time. It is clear that there is a minimum level of usage not necessarily affected by weather, but as the weather gets colder, usage increases in step.

Figure 2



Q. Describe the Company's other inputs for number of customers and use-per-customer?

A. Population and employment levels are the primary economic variables used as a forecast driver for the number of residential customers. These data are obtained from Woods and Poole (W&P), which provide growth factors at the county level. The Company also uses a seasonal pattern variable to capture seasonal effects. For the use-per-customer forecast the Company utilizes monthly indicator variables as well we weekend/weekday indicator variables. This accounts for any monthly and weekday differences in the data that are separate from weather. The Company now also utilizes its seasonal variable and ARIMA terms in the UPC forecast model.

Q. What is the Company's model selection process generally.?

A. The Company utilizes the Akaike information criterion (AIC) for model selection. This metric incorporates both model fit and parsimony. Generally the better a model can explain the data and the fewer the variables, the better the AIC number will be. The Company notes that as opposed to its previous rate case, it now keeps variables that may be insignificant on a statistical level but relevant on an economic level.

Q. Why does Staff recommend the use of Oregon residential new construction in the model?

A. Of the two components of the load forecast, customer growth has been traditionally the more difficult value to forecast. The values for customer growth display a greater variance and errors in the forecast are more common. One way to combat this is to provide the model with the most useful information possible.

Q. Please summarize the Company's load forecasting results.

A. The Company has forecast a total of roughly 87 thousand therms sales to non-transportation customers in the test year. 55 percent of that is made up of residential demand, with 36 percent being commercial.

Q. How does the Company forecast loads for its large volume customers?

A. The Company annually surveys its large volume customer base and annually meets face to face with many of its largest volume accounts. The Company forecasts its Special Contract 900 2020 loads by either applying a one percent increase to its 2019 actuals, or by applying growth factors based on internal knowledge.

Q. Do you find this approach reasonable?

A. In general, yes. Given the small number of customers, it is reasonable to perform a face-to-face meeting and case-by-case forecast for each customer. Staff recommends however that an econometric model be utilized to verify the forecasts.

Q. Does Staff find the Company's overall methodology reasonable?

A. Yes, the Company's methodology is generally in line with industry standards in the region. The Company includes appropriate drivers in its model and utilizes sound econometric processes to ensure the results are mathematically valid. The model selection could be automated to reduce the likelihood of human error when running a model 200 times, but Staff supports the use of the AIC as a selection metric.

Q. What is the result of the Company's forecast on revenues?

A. The Company is projecting an increase of approximately $360 thousand due to additional load.

Q. Does Staff have any further comments?

A. Yes. Staff notes that the Company did not address the impacts of COVID-19 in opening testimony, likely because the initial testimony was written prior to the large extent of cases occurring in the United States. Four months have now passed since numerous pandemic-related restrictions were imposed in Oregon. Reopening has begun, but the speed and duration of further reopening measures remain uncertain. Although the Company's models do contain economic drivers whose forecasts will incorporate the potentially large impacts of the global pandemic on demand once updated by third parties, Staff asks that the Company address this issue on the record. Given the vast and yet unknown extent of COVID-19, Staff is not yet advocating for an update to the methodology in this case. Staff simply asks that the Company provide a discussion on COVID-19 as it relates to the Company's load forecast.

ISSUE 2. DECOUPLING

Q. Please provide a background on this issue.

A. In Docket No. UG 287, the parties agreed to continue Cascade's current decoupling mechanism, the Conservation Alliance Plan (CAP). They further agreed that Staff and CUB will organize a decoupling workshop for September 2016 to explore whether and how Cascade may implement a real-time weather adjustment. They agreed to initiate full review of the mechanism on September 30, 2019, with any proposed changes to be effective January 1, 2020.[4]

Q. Did the Company hold a workshop to review the mechanism?

A. Yes, the Company held workshops on October 18th, November 1st, and November 15th, 2019. AWEC, CUB, and Staff participated in the workshops.

Q. What was the outcome of the workshops?

A. The Commission approved Cascade's proposed changes to the CAT in Docket No. Number ADV 1071 at the December 17, 2019 public meeting. The advice filing resulted in the following changes:

- Three percent annual limit on CAP surcharges. Amounts in excess of three percent are deferred to the next period.
- Utilization of the modified blended treasury rate for interest rate calculations of CAP deferral balances.

[4] See Docket No. UG 287, Order No. 15-412 at 5 (Dec. 28, 2015).

- The Company will initiate a review of the CAP mechanism on September 30, 2024, with any proposed changes to be effective January 1, 2025.

Q. Does Staff have any further recommended changes to the mechanism?

A. No, in light of the recent changes implemented through the workshop, Staff finds the current approach reasonable. Staff encourages the Company to continue to monitor the difference between new and current customer usage. Staff believes that new homes may have a different UPC than older homes, and this could be more accurately captured by the Company's mechanism with an updated methodology in the future if a substantial difference is identified. Staff also reviewed the Company's margin per customer calculations and found them to be correct and in-line with the approved methodology.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 390
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION OF OREGON

STAFF EXHIBIT 601

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Scott Gibbens
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Economist Energy Rates, Finance and Audit
ADDRESS:	201 High St. SE Ste. 100 Salem, OR 97301-3612
EDUCATION:	Bachelor of Science, Economics, University of Oregon Masters of Science, Economics, University of Oregon
EXPERIENCE:	I have been employed at the Oregon Public Utility Commission (Commission) since August of 2015. My current responsibilities include analysis and technical support for electric power cost recovery proceedings with a focus in model evaluation. I have been the power cost team manager since January 2017. I have worked on the following power cost dockets: PAC UE 307, UE 309, UE 323, UE 327, UE 339, UE 344, UE 356, UE 361, and current UE 375 and UE 379. PGE UE 308, UE 310, UE 319, UE 329, UE 335, UE 346, UE 359, UE 362, and current UE 377. IPC UE 301, 305, UE 314, UE 320, UE 333, UE 336, UE 350, UE 354, UE 366, and current UE 376. I've also performed analysis and review on a variety of other issues at the Commission. I have reviewed issues and made recommendations to the Commission in the following general rate cases: AVA UG 325, UG 366 and current UG 389; NWN UG 344, and current UG 388; PAC current UE 374; PGE UE 319, and UE 335; and CNG UG 305, UG 347 and current UG 390. Prior to working for the OPUC I was the operations director at Bracket LLC. My responsibilities at Bracket included quarterly financial analysis, product pricing, cost study analysis, and production streamlining. Previous to working for Bracket, I was a manager for US Bank in San Francisco where my responsibilities included coaching and team leadership, branch sales and campaign oversight, and customer experience management.

CASE: UG 390
WITNESS: SCOTT GIBBENS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 602
Cascade 2020 Draft IRP Chapter 3

Exhibits in Support
Of Opening Testimony

July 30, 2020

CHAPTER 3

DEMAND FORECAST

Overview

Key Points

- Cascade initiates its forecast with analyses of demand area, weather, and HDDs.
- Peak day is analyzed deterministically with coldest day in 30 years, and stochastically using 10,000 Monte Carlo simulated draws.
- Cascade uses a 60 °F reference temperature to calculate HDDs.
- The Company utilizes dynamic regression modeling techniques for customer and annual demand forecasts.
- High and low scenarios are included and alternative forecasting assumptions were considered.
- Cascade expects system load growth to average 1.26% per year over the 20-year planning horizon.
- Uncertainties in the future may cause differences from the Company's forecast.

Each year Cascade develops a 20-year forecast of customers, therm sales, and peak requirements for use in short-term (annual budgeting) and long-term (distribution and integrated resource planning) planning processes. Sources of this forecast include historic data, market intelligence, and regional economic data from Woods & Poole. This forecast is a robust portfolio of estimates created by expanding a single best-estimate forecast, which includes various potential economic, demographic, and marketplace eventualities, into scenarios such as low, expected, and high growth. The scenarios are used for distribution system enhancement planning and as inputs in optimization models to determine the reasonable least cost, least risk mix of supply and Demand Side Management (DSM) resources, revenue budgeting, and load forecasts associated with the purchased gas cost process.

Demand Areas

For the 2020-2039 planning horizon, Cascade forecasted at both the citygate and rate class levels. This is a change of methodology from previous years when certain models were built from the district or zonal level. Cascade has a total of 76 citygates of which nine citygates feed only non-core customers and the remaining 67 serve at least one core customer. Of the 67 citygates that serve core customers, twenty are grouped into eight different citygate loops. Therefore, Cascade forecasts a total of 55 areas. Each of these areas contain multiple rate classes, resulting in approximately 200 individual dynamic regression models. Each citygate is assigned to a weather location. For this IRP, the Company assigned the citygates to the closest weather location by distance. The citygate results are rolled up into zones and districts which segregate Cascade's system based on pipelines and weather, as shown in Appendix B. Figure 3-1 provides a cross reference for the demand areas.

Figure 3-1: Demand Areas

Citygate	Loop	State	Weather Location	Zone
7TH DAY SCHOOL		WA	Yakima	10
A/M RENDERING	Sumas SPE Loop	WA	Bellingham	30-W
ACME		WA	Bellingham	30-W
ARLINGTON		WA	Bellingham	30-W
ATHENA		OR	Pendleton	ME-OR
BAKER		OR	Baker City	24
BELLINGHAM 1 (FERNDALE)	Sumas SPE Loop	WA	Bellingham	30-W
BEND	Bend Loop	OR	Redmond	GTN
BREMERTON (SHELTON)		WA	Bremerton	30-S
BURBANK HEIGHTS	Burbank Heights Loop	WA	Walla Walla	20
CASTLE ROCK		WA	Bremerton	26
CHEMULT		OR	Redmond	GTN
DEHAWN DAIRY		WA	Yakima	10
DEMING		WA	Bellingham	30-W
EAST STANWOOD	East Stanwood Loop	WA	Bellingham	30-W
FINLEY		WA	Walla Walla	20
GILCHRIST		OR	Redmond	GTN
GRANDVIEW		WA	Yakima	10
HERMISTON		OR	Pendleton	ME-OR
HUNTINGTON		OR	Baker City	24
KALAMA #1		WA	Bremerton	26
KALAMA #2		WA	Bremerton	26
KENNEWICK	Kennewick Loop	WA	Walla Walla	20
LA PINE		OR	Redmond	GTN
LAWRENCE		WA	Bellingham	30-W
LDS CHURCH		WA	Bellingham	30-W
LONGVIEW-KELSO	Longview South Loop	WA	Bremerton	26
LYNDEN	Sumas SPE Loop	WA	Bellingham	30-W
MADRAS		OR	Redmond	GTN
MCCLEARY (ABERDEEN/HOQUIAM)		WA	Bremerton	30-S
MILTON-FREEWATER		OR	Walla Walla	ME-OR
MISSION TAP		OR	Pendleton	ME-OR
MOSES LAKE		WA	Yakima	20
MOUNT VERNON	Sedro-Woolley Loop	WA	Bellingham	30-W
MOXEE (BEAUCHENE)		WA	Yakima	11
NORTH BEND		OR	Redmond	GTN
NORTH PASCO	Burbank Heights Loop	WA	Walla Walla	20
NYSSA-ONTARIO		OR	Baker City	24
OAK HARBOR/STANWOOD	East Stanwood Loop	WA	Bellingham	30-W

Citygate	Loop	State	Weather Location	Zone
OTHELLO		WA	Walla Walla	20
PASCO	Burbank Heights Loop	WA	Walla Walla	20
PATTERSON		WA	Yakima	26
PENDLETON		OR	Pendleton	ME-OR
PRINEVILLE		OR	Redmond	GTN
PRONGHORN		Redmond	Redmond	GTN
PROSSER		WA	Yakima	10
QUINCY		WA	Yakima	11
REDMOND		OR	Redmond	GTN
RICHLAND (Richland Y)	Kennewick Loop	WA	Walla Walla	20
SEDRO/WOOLLEY	Sedro-Woolley Loop	WA	Bellingham	30-W
SELAH	Yakima Loop	WA	Yakima	11
SOUTHRIDGE	Kennewick Loop	WA	Walla Walla	20
SOUTH BEND	Bend Loop	OR	Redmond	GTN
SOUTH LONGVIEW	Longview South Loop	WA	Bremerton	26
STANFIELD		OR	Pendleton	GTN
STEARNS (SUNRIVER)		OR	Redmond	GTN
SUNNYSIDE		WA	Yakima	10
UMATILLA		OR	Pendleton	ME-OR
WALLA WALLA		WA	Walla Walla	ME-WA
WALLULA		WA	Walla Walla	ME-WA
WCT-CNG INTERCONNECT	Sumas SPE Loop	WA	Bellingham	30-W
WENATCHEE		WA	Yakima	11
WOODLAND		WA	Bremerton	26
YAKIMA CHIEF RANCH		WA	Yakima	10
YAKIMA TRAINING CENTER		WA	Yakima	11
YAKIMA/UNION GAP	Yakima Loop	WA	Yakima	11
ZILLAH (TOPPENISH)		WA	Yakima	10

Weather

Historical weather data is provided by a contractor, Schneider Electric. Historically, Cascade has accessed data from NOAA (National Oceanic and Atmospheric Administration), but found many months/locations with missing data. The current forecast uses 30 years of recent history as the normal or expected weather. The forecast model takes the 30 previous years, converts the data to heating degree days (HDDs), then averages the HDDs into average days to create a normal or expected year. Cascade has seven weather locations with four located in Washington and three in Oregon. The three locations in Oregon are Baker City, Pendleton, and Redmond.

Heating Degree Days

HDD values are calculated with the daily average temperature, which is the simple average of the high and low temperatures for a given day. The daily average is then subtracted from an HDD degree threshold (for example 60 °F) to create the HDD for a given day. Should this calculation produce a negative number, a value of zero is assigned as the HDD. Therefore, HDDs can never be negative. The HDD threshold number is designed to reflect a temperature below which heating demand begins to significantly rise. The historical threshold for calculating HDD has been 65 °F. However, when modeling gas demand based on weather, Cascade has determined that lowering the threshold to 60 °F produces more accurate results for the Company's service area. Figures 3-2 and 3-3 illustrate why the lower threshold is preferable. These figures show that heating demand does not begin to increase significantly until an HDD of five (65 °F minus 60 °F) is reached, if the traditional HDD threshold of 65 °F is utilized. Lowering the HDD threshold improves the R^2 statistic, thus giving a better measure of the relation between HDD and therms (measurement of heat usage). Cascade ran a cross-validation analysis to compare the forecast with actual weather and customer counts in the regressions (e.g. 2011 customers, with 2011 weather, to cross-validate 2011). When comparing, using a 65 °F reference temperature, the cross-validation analysis had a mean absolute percentage error (MAPE) of 14.9%. When using a 60 °F reference temperature, the MAPE improved to 7.62%.

Figure 3-2: Acme Therm/HDD with 65°F Reference Temperature

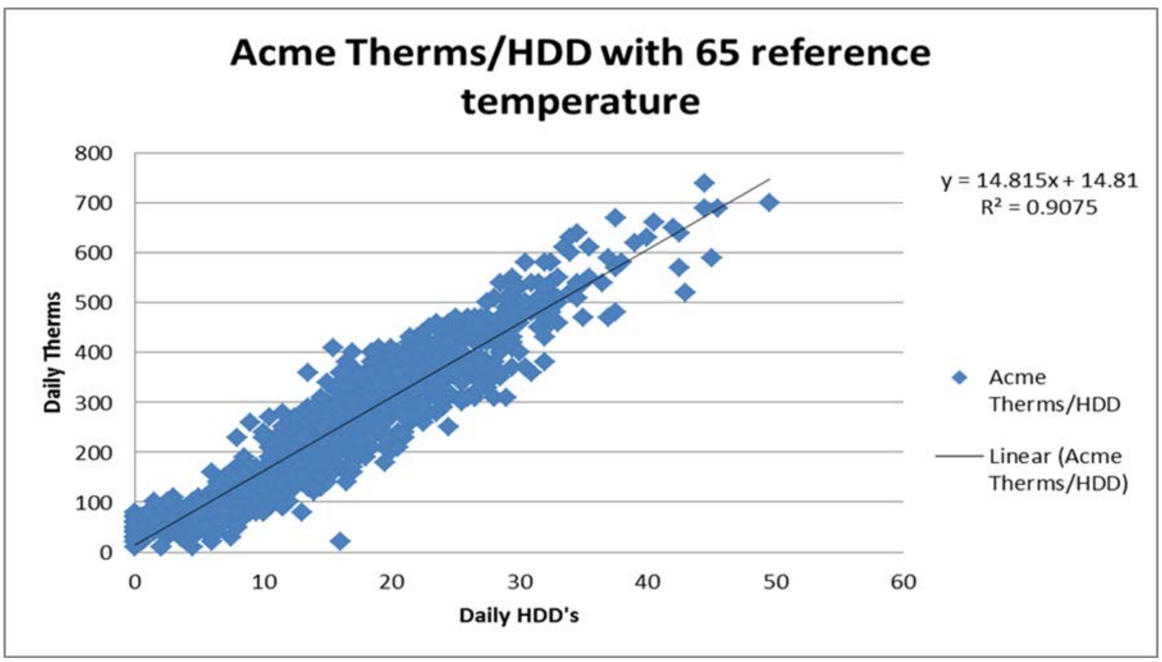
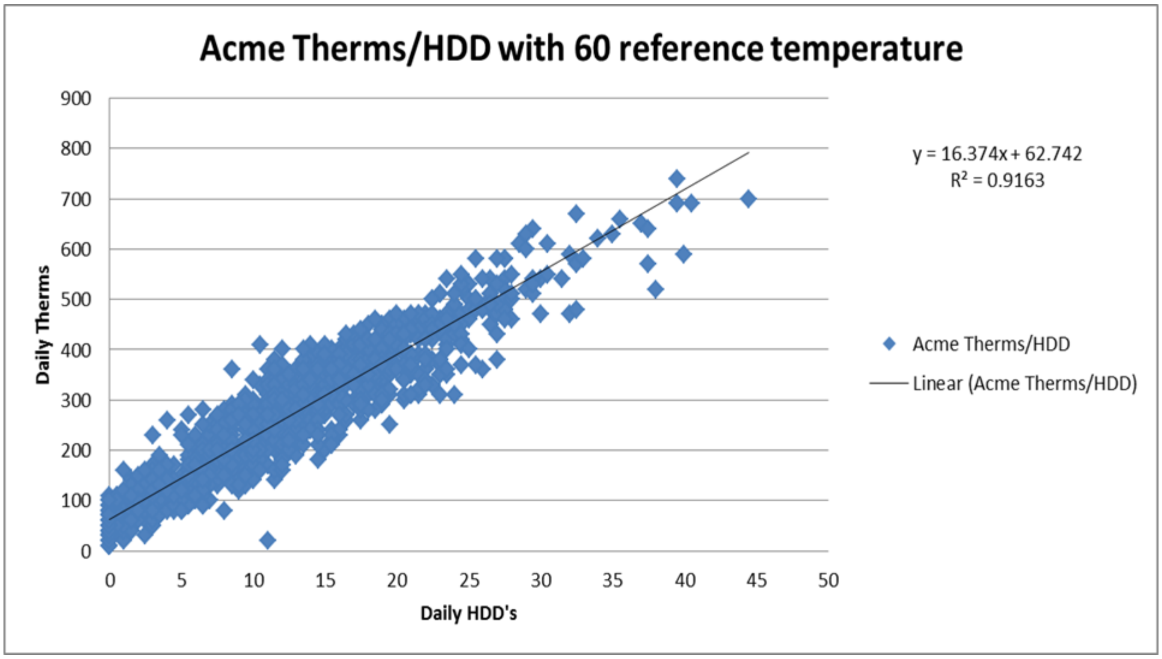


Figure 3-3: Acme Therm/HDD with 60°F Reference Temperature



Peak Day HDDs

In order to ensure satisfaction of core customer demand on the coldest days, Cascade develops a deterministic and a stochastic peak day usage forecast in conjunction with annual base load forecasts. Peak day forecasts enable Cascade to make prudent distribution system and peak upstream pipeline capacity planning decisions to fulfill its responsibility to provide heating under all but *force majeure* conditions, particularly as most space-heating customers will have no alternative heating source during the coldest days in the event gas does not flow.

The deterministic peak day that was analyzed in the forecast model is a system-wide weighted HDD coldest in 30 years value.

This peak day will give Cascade the deterministic outcome with varying amounts of demand. The deterministic peak HDD methodology allows Gas Supply to plan for the highest peak event during a heating season.

System-wide maximum peak HDDs are determined by first selecting the system-wide single coldest day recorded in the past 30 years. To determine the system-wide single coldest day, HDDs from all seven weather stations are considered, giving appropriate weight to the weather stations. The weights are determined by the increase in demand experienced with an increase in one HDD. Cascade has found December 21, 1990, to have the highest, system-weighted HDD, at 56 HDDs for this period.

For SENDOUT®, Cascade uses the system-wide maximum peak HDDs method. Cascade applies the HDDs experienced on December 21, 1990, to each of the regressions in the forecast model. For example, all citygates associated with the Yakima weather station use the HDD for Yakima on December 21, 1990, and similarly for all the other weather stations and citygates. This provides a highest demand scenario for peak demand load based on 30 years of weather history for each citygate. Applying December 21, 1990, weather temperatures to today's forecast methodology gives Cascade an accurate representation of the demand the Company could expect to experience if this weather happened during the planning horizon.

Cascade is actively expanding its peak day methodology to include stochastic elements such as Monte Carlo analysis. More on this peak day analysis can be found on page 3-11. Cascade will also continue to investigate how various peak day standards affects the core demand load areas which are short of capacity. This investigation will include (but not be limited to) analysis of how other regional utilities look at peak day, discussions with the various weather services, and continued dialogue with Commission Staff and other interested parties.

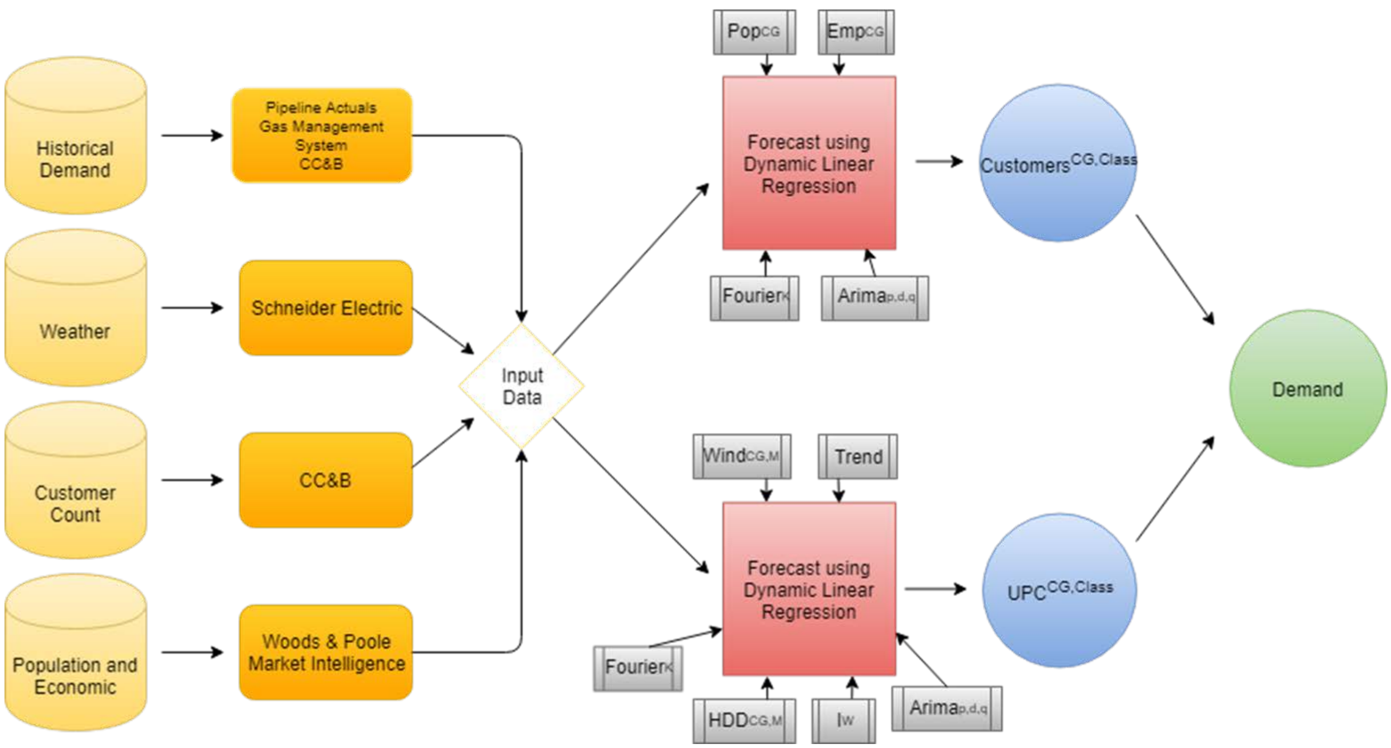
Wind

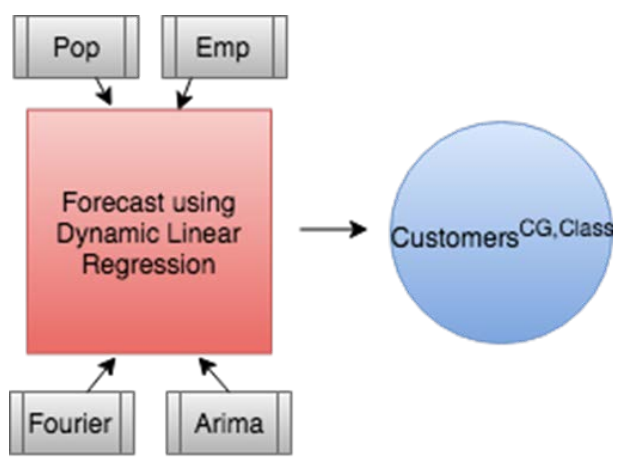
Wind values are calculated with the daily average wind speed, which is the simple average of the high and low wind speeds for a given day. Wind speeds are also weather location specific, similar to HDDs.

Demand Overview

Figure 3-4 provides a roadmap for Cascade's demand forecast. The inputs are displayed along with their sources in yellow and gold. The customer forecast and use-per-customer (UPC) forecast are shown in red along with their respective inputs into the model. Finally, the customer forecast is multiplied by the use-per-customer forecast to create the final demand forecast.

Figure 3-4: Demand Forecasting Process Overview





Customer Forecast Methodology

Customer count forecasts are designed to reflect both demographic trends and economic conditions both in the short- and long-term. Cascade uses population and employment growth data from Woods & Poole (W&P). W&P growth forecasts are provided at the county level. It should be noted that W&P forecasts are adjusted when the internal intelligence about a demand area indicates a significant difference from W&P regarding observed economic trends. Cascade utilizes dynamic regression models for the customer forecast as well as regression models for the UPC forecast, which will be discussed in the next subchapter. Below is the formula the Company used to run the regressions:

$$C_{Class}^{CG} = \alpha_0 + \alpha_1 Pop^{CG} + \alpha_2 Emp^{CG} + Fourier(k) + ARIMA\epsilon(p,d,q)$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class$
- $Pop^{CG} = Population\ by\ Citygate$
- $Emp^{CG} = Employment\ by\ Citygate$
- $Fourier = Terms\ used\ to\ capture\ seasonal\ patterns$
- $k = Number\ of\ Fourier\ terms\ used\ in\ model$
- $ARIMA\epsilon(p,d,q) =$ $Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d\ difference\ terms, and\ q\ moving\ average\ terms.$

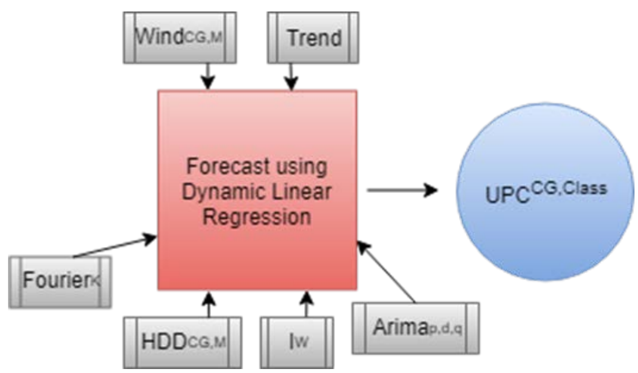
Cascade runs this model approximately 200 times to account for each customer class by citygate. The Company begins by testing seven different combinations of the regressors in both dynamic regression models and one Autoregressive Integrated Moving Average (ARIMA) model. The dynamic regression models test: Fourier, Population, Employment, Population + Fourier, Employment + Fourier, and Employment + Population + Fourier. The last model is called an ARIMA model, which uses ARIMA terms and no regressors. Unlike the dynamic regression models, the 'ARIMA Only' model's ARIMA term is not strictly modeling the errors, but is used as a model for the entire data set. The method used to compare and select a model is called the AIC, or the Akaike Information Criterion. This is a measure of the relative quality of statistical models, relative to each of the other models. In each of the models, except for the 'ARIMA Only' model, an ARIMA term is used to capture any structure in the errors (or residuals) of the model. In other words, there could be predictability in the errors, so they could be modeled as well. If the data is non-stationary, the ARIMA function will difference the data. Most times, the data does not require differencing, or only needs to be differenced once. Once the best model is selected for each customer class by citygate, a forecast is performed using the selected model.

Customer count and therm forecasts are augmented by revisions to the base data and output to create a portfolio of potential scenarios. Low and high growth scenarios are created from the confidence intervals from the forecast model. These scenarios, along with the original, best-estimate, expected scenario encapsulate a range of most-likely possibilities given known data. The most recent W&P data indicates an average annual population growth of 0.85% between 2020 and 2039 for Cascade's service territory. The projected customer growth is provided in Appendix B. Based on historical experience and given expected weather, Cascade expects system load will likely remain within a range bound by the low and high growth scenarios.

Among other reasons, the Company believes that growth in the following regions will be a major factor in any forecasted system-wide deficiency:

- Bend, Oregon – According to Portland State University's (PSU) Population Research Center, the city of Bend is estimated to have an average annual growth rate of 10.22%. This is credited to factors such as job growth, increases in ratios of full-time to part-time jobs, poverty rates decreasing, and others. A study by a personal finance website called WalletHub found Bend to be the 3rd fastest growing city in the U.S. [1]
- Redmond, Oregon - The city of Redmond seems to be absorbing much of Bend's rapid growth. With a lower cost of living and a strong job market, Redmond is boasting an annual average growth rate of 10.14%, according to PSU's Population Research Center. [2]
- Tri-Cities, Washington – According to Washington's Office of Financial Management's data released in June 2019, Benton and Franklin counties were the fastest growing counties in the state between 2018 and 2019. These counties are growing at an impressive 2.2% and 2.3%, respectively, between 2018 and 2019. This rapid growth is credited primarily to net migration (people moving in versus people moving out). [3]

Use-Per-Customer (UPC) Forecast Methodology



As previously mentioned, Cascade utilizes regression models for the UPC part of the demand forecast as well. Sources for the inputs into this model are pipeline actuals, Cascade's gas management system, and Cascade's Customer Care and Billing System (CC&B). Cascade developed the UPC coefficient by gathering historical pipeline demand data by day. The pipeline demand data includes core and non-core usage. The non-core data is backed out using Cascade's measurement data stored in the Company's Aligne energy transaction system which leaves daily core usage data. The daily data is then allocated to a rate schedule for each citygate by using CC&B. This data is then divided by number of customers to come up with a UPC number for each day and for each rate schedule at each citygate.

Below is the model used for the UPC forecast:

$$\frac{Therms}{C_{Class}^{CG}} = \alpha_0 + \alpha_1 HDD^{CG,M} + \alpha_2 I_w + \alpha_3 T + \alpha_4 WIND^{CG,M} + Fourier(k) + ARIMA(p,d,q)$$

[1] https://wallethub.com/edu/fastest-growing-cities/7010/
[2] https://www.oregonlive.com/news/erry-2018/05/3772ef0a5e1889/how_fast_is_each_oregon_city_g.html
[3] https://www.tricitiesbusinessnews.com/2019/06/2019-population-growth/

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class.$
- $HDD^{CG} = Heating\ Degree\ Days\ from\ Weather\ Location$
- $m = month$
- $w = weekend$
- $T = Trend$
- $I = Indicator\ variable, 1\ if\ weekend, and\ 0\ if\ weekday.$
- $WIND^{CG} = Daily\ average\ wind\ speed\ from\ Weather\ Location$
- $Fourier(k) = Captures\ seasonality\ of\ k\ number\ of\ seasons.$
- $ARIMA(p,d,q) = Indicates\ model\ has\ p\ autoregressive\ terms,\ d\ difference\ terms, and\ q\ moving\ average\ terms.$

Cascade runs this model for each of the 55 citygates and citygate loops by customer class where applicable, resulting in approximately 200 models. Cascade starts with the above model for Residential, Commercial, and Industrial customer classes. A change in methodology from previous IRPs involves keeping variables in the model that may appear non-significant on a statistical level but relevant on an economic level. This could be a shoulder month, i.e. September, showing insignificance in a model but economically known to affect the annual load shape of residential customers. Also, Cascade now runs the UPC forecast with Fourier and ARIMA terms.

Peak Day Forecast Methodology

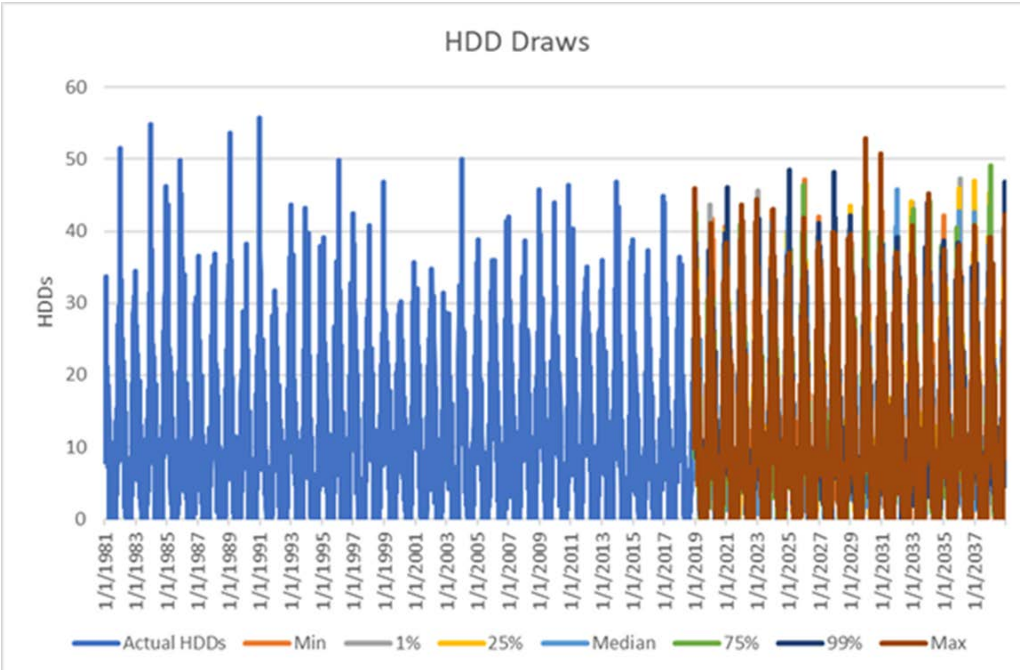
Cascade's methodology for peak day forecasting is similar to its forecast of demand. For a deterministic forecast, Cascade utilizes the same dynamic regressions as before but with a peak day HDD inserted. This peak day HDD comes from the coldest on record in the last 30 years. Once this peak day is inserted for every year of the forecast, Cascade deterministically derives a peak day usage forecast.

The Company also utilizes Monte Carlo simulation to stochastically analyze the peak day behavior. Through the statistical program R, Cascade runs 10,000 Monte Carlo draws in each weather zone, making sure to correlate the draws based on historical correlations between each weather zone. This results in 10,000 draws of various weather behavior based on historical averages, standard deviations, and correlations between weather zones. Further discussion regarding the Monte Carlo methodology can be found in Chapter 9, Resource Integration.

In this stochastic analysis, Cascade analyzed many attributes, including the minimum, the maximum, and percentiles such as the 1st, 25th, 75th, and the 99th. The 99th percentile is then used to calculate the Value-at-Risk (VaR) metric to compare with the VaR limits discussed in Chapter 9.

Figure 3-5 displays the historical weather data along with the Monte Carlo simulated weather forecast. The historical weather data represents actual HDDs. The 10,000-draw simulation includes the following draws: Minimum, 1%, 25%, median, 75%, 99%, and maximum.

Figure 3-5: Historical vs. Monte Carlo Simulated Weather



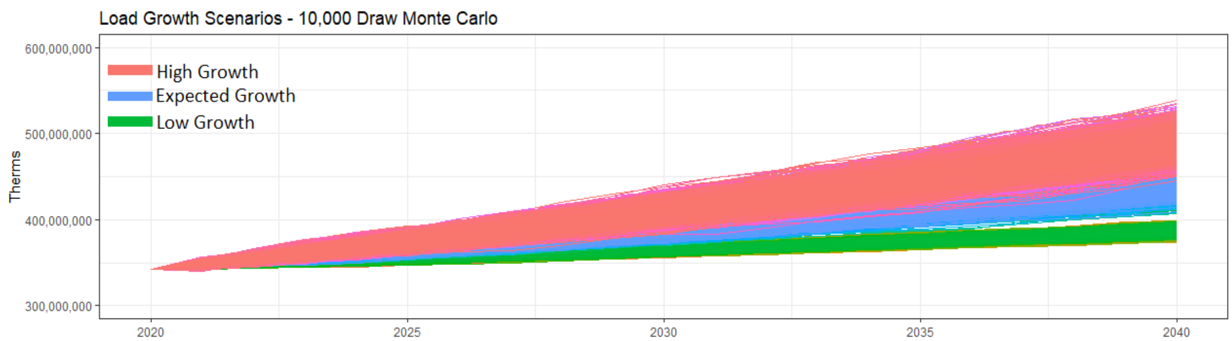
Scenario Analysis

Cascade stress tests the load forecast in SENDOUT® by using alternative forecasting assumptions. These alternative forecasting assumptions refer to changing factors that influence demand. Alternative assumptions include high and low customer growth, and a stochastic study of weather using Monte Carlo simulations. These altered assumptions provide an effective tool for analyzing and stress testing the forecasts. Figure 3-6 identifies the list of scenarios. Figure 3-7 displays the scenario analysis over the planning horizon.

Figure 3-6: Growth and Weather Scenarios

Scenario	Weather	Growth	UPC
Base Case	Expected	Expected	Expected
Low Growth	Expected	Low	Expected
Low Growth Stochastic	Monte Carlo Weather	Low	Expected
High Growth	Expected	High	Expected
High Growth Stochastic	Monte Carlo Weather	High	Expected

Figure 3-7: Scenario Analysis Demand Forecast (Volumes in Therms)



The base case contains expected weather, customer growth, and use per customer. The base case also has one max peak day event for each weather zone. Expected weather is the average weather over the past 30 years. High and low growth scenarios, discussed more on page 3-17, explain that Cascade uses modifiers to represent higher than expected growth and lower than expected growth. The high and low growth stochastic scenarios are represented by the 10,000 red and green lines above in Figure 3-7. This provides a stochastic stress test of Cascade's growth scenarios. Stochastic tests such as these on demand are only to show how weather and/or growth can impact demand over the 20-year planning horizon. Cascade also performs a deep sensitivity analysis utilizing Monte Carlo runs for other variables such as price. Monte Carlo analysis is discussed further in Chapter 9.

Forecast Results

Load across Cascade's two-state service territory is expected to increase at an average annual rate of 1.26% over the planning horizon, with the Oregon portion outpacing Washington, 1.58% versus 1.15%. Figure 3-8 shows the expected core load volumes by state.

Figure 3-8: Expected Core Load by State (Volumes in Therms)

Year	Washington	Oregon	System
2020	256,632,337	86,191,685	342,824,022
2025	272,364,811	93,774,368	366,139,180
2030	289,075,933	101,716,374	390,792,307
2035	305,787,078	109,658,358	415,445,436
2039	319,102,685	115,997,548	435,100,233
Average Annual Growth	**1.15%**	**1.58%**	**1.26%**

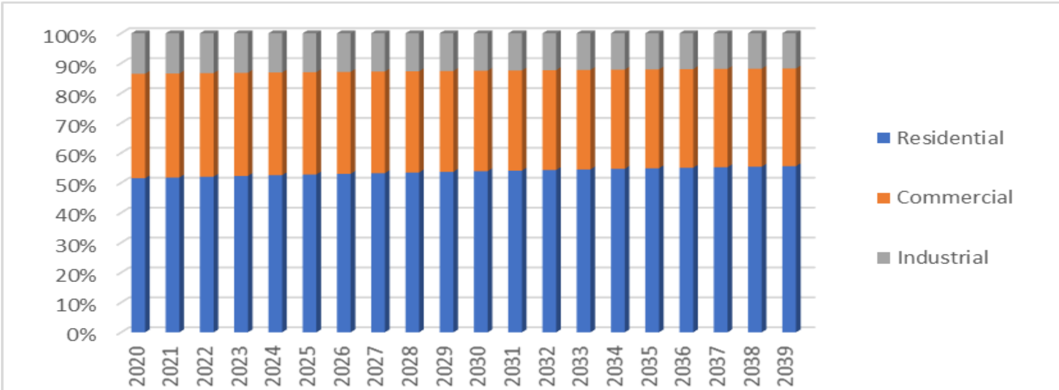
Load growth across Cascade's system through 2039 is expected to fluctuate between 0.78% and 1.80% annually, accounting for leap years. Load growth is split between residential, commercial, and industrial customers. Residential and commercial customer classes are expected to grow annually at an average rate of 1.66% and 0.91%, while industrial expects a growth rate of approximately 0.51%. Figure 3-9 shows the percentage of core growth by class over the planning horizon.

Figure 3-9: Expected Core Load Growth by Class

Average Growth	Residential	Commercial	Industrial	System
2020-2024	1.91%	1.00%	0.55%	1.41%
2025-2029	1.68%	0.88%	0.47%	1.25%
2030-2034	1.62%	0.91%	0.52%	1.24%
2035-2039	1.50%	0.87%	0.51%	1.17%
Average Annual Change	**1.66%**	**0.91%**	**0.51%**	**1.26%**

In absolute numbers, system load under normal weather conditions is expected to grow annually at an average of 4.9 million therms. A majority of core load today is residential. Cascade projects the ratio between residential, commercial, and industrial to increase in favor of residential customers. Residential customers are expected to grow from 54.5% of the total core load to 57% of the total core load by 2039. Figure 3-10 displays the relative percentage relationship of expected loads by class.

Figure 3-10: Expected Load Stack by Class



Cascade expects residential customers to increase load at an annual average growth of approximately 3.4 million therms and commercial core customers to increase load at an annual average growth of approximately 1.2 million therms over the 20-year planning horizon. Industrial customers are expected to increase load at an annual average growth of approximately 247,000 therms over the same period. Figure 3-11 displays the expected core load volumes by class.

Figure 3-11: Expected Load Growth by Class (Volumes in Therms)

Year	Residential	Commercial	Industrial
2020	176,668,996	119,706,359	46,448,668
2025	193,278,462	125,290,909	47,569,808
2030	210,595,205	131,345,978	48,851,124
2035	227,911,914	137,401,072	50,132,450
2039	241,732,639	142,220,037	51,147,557
Average Annual Change	**1.65%**	**0.91%**	**0.51%**

Load growth is primarily a result of increased customer counts. The number of commercial and industrial customers is expected to increase at a slightly faster rate than therm usage, whereas residential customer growth is similar to the residential load growth. Figure 3-12 displays the expected customer counts by class.

Figure 3-12: Expected Customer Counts by Class

Year	Residential	Commercial	Industrial
2020	3,152,556	445,063	9,047
2025	3,464,692	467,980	9,687
2030	3,776,826	490,896	10,326
2035	4,088,960	513,812	10,966
2039	4,338,669	532,146	11,477
Average Annual Change	**1.65%**	**0.93%**	**1.22%**

Geography

Bend, Oregon is a major driver in the growth rate. The central part of the state is expected to see a large increase in growth. Figure 3-13 shows the percentage growth of load by each of Cascade's weather locations. Figure 3-14 shows the percentage growth of load by each pipeline zone over the planning horizon. Lastly, Figure 3-15 displays a range of core peak day growth over the planning horizon along with a sampling of peak day therms. Peak day average annual growth is expected to be approximately 1.38%.

Figure 3-13: Oregon 20-Year Load Growth by Weather Location (Volumes in Therms)

Weather	Average Annual Growth	2020 Load	2039 Load
Baker City	0.70%	9,984,100	11,380,900
Pendleton	0.90%	14,607,900	17,306,000
Redmond	1.83%	61,166,000	86,878,800
Oregon	**1.56%**	**85,758,000**	**115,565,700**

Figure 3-14: System 20-Year Load Growth by Pipeline Zone

Zone	Load Growth
Zone 10	-0.51%
Zone 11	23.74%
Zone 20	51.36%
Zone 24	15.04%
Zone 26	10.60%
Zone 30-S	18.58%
Zone 30-W	24.77%
Zone GTN	43.72%
Zone ME-OR	18.96%
Zone ME-WA	19.56%

Figure 3-15: Expected Peak Day Growth (Volumes in Therms)

Period	Peak Day Growth	Year	Peak Day Therms
2020 – 2024	1.56%	2021	3,612,900
2025 – 2029	3.04%	2026	3,890,000
2030 – 2034	2.90%	2032	4,222,500
2035 – 2039	2.80%	2037	4,499,600
Average Annual Growth	**1.38%**		

High and Low Growth Scenarios

High and low growth scenarios were created by examining the confidence intervals resulting from the customer forecast model. Cascade derived from these intervals a high growth modifier of 1.5 times the expected growth, and a low growth modifier of 0.5 times the expected growth. Cascade projects an average annual growth rate of 1.26% in load growth on the expected case, 0.63% on the low band and 1.88% on the high band. Figure 3-16 displays the expected total system load growth across various scenarios.

Figure 3-16: Expected Total System Load Growth (By Percentage) Across Scenarios

Range	Low	Expected	High
2020-2024	0.71%	1.41%	2.12%
2025-2029	0.63%	1.25%	1.88%
2030-2034	0.62%	1.24%	1.87%
2035-2039	0.59%	1.17%	1.76%
2020-2039	**12.70%**	**26.92%**	**42.81%**
Average Annual Change	**0.63%**	**1.26%**	**1.88%**

Load growth under poor economic conditions is expected to average 0.63% annually over the forecast period, while load growth under good economic conditions is expected to average 1.88% annually. The cumulative effect of high growth over 20 years could result in an additional load of 54 million therms, while low growth could result in a load of 48 million therms less than the expected scenario predicts. Figure 3-17 shows the expected total system load across these scenarios.

Figure 3-17: Expected Total System Load Growth Across Scenarios (Volumes in Therms)

Year	Low	Expected	High
2020	342,824,000	342,824,000	342,824,000
2025	354,330,108	366,139,200	378,257,147
2030	366,104,897	390,792,300	416,960,879
2035	377,513,053	415,445,400	456,899,827
2039	386,367,323	435,100,200	489,601,247
2020-2039	**43,543,323**	**92,276,200**	**146,777,247**
Average Annual Load Increase	**2,291,754**	**4,856,642**	**7,725,118**

Alternative Forecasting Methodologies

Cascade has expanded its forecasting methodologies used in the customer forecast into the use-per-customer (UPC) forecast. Cascade now uses Fourier terms and ARIMA terms in its UPC forecasting methods. Cascade utilizes R as its primary statistical analysis software and uses models that follow a dynamic regression methodology. The Company plans to continue improving the customer and demand forecast model through R.

The Company is responsive to several regulatory principles in forecasting. These include:

- A desire for precision and a high degree of accuracy;
- A universal understanding that forecasts should mirror future realities but may have unanticipated swings in either direction;
- A disconnect between planning and operational functions, in that natural gas purchasing and dispatch will be based on immediate needs which, in actuality, are guaranteed to vary from the plan (per the previous bullet);
- An understanding that an increased cost of improved precision sometimes has decreasing customer benefits;
- A need to meet Regulators' expectation that the Company show continual improvement because new tools are available. For example, the concept of "adaptive management" can be applied;
- The major differences in accounting treatment between the states regarding test years for ratemaking purposes (that is, for general rate case filings) and not necessarily for planning. At this time, Oregon uses future test year accounting while Washington employs a historic test year;
- The fuzziness of historic data that includes effects of energy efficiency, retail price (from annual PGA—purchased gas adjustment—changes and other rate changes), sometimes abnormal weather, new technology, and then-unique economic conditions (e.g., recession, interest rates, etc.). Cascade uses actual historic data. The term fuzziness is used in the context of basing forecasts on past-period data that includes many variables, any one of which may have increased or decreased in the intervening time between historical occurrence and forecasted periods. This causes difficulty for utilities trying to isolate primary factors for greater precision of long-term calculations.
- Unknown and uncertain future changes such as the assumptions around carbon policy and other environmental externalities; and
- A need to demonstrate support for assumptions such as growth in customers, use per customer and changes from previous forecasts, type of use (i.e., heating, manufacturing, etc.), to name a few.

The preceding subchapter illustrates the complexity of forecasting and highlights areas of stakeholder attention. Best efforts at appropriate reasonable cost distill these factors into a generally accepted forecast with recognition of inherent uncertainties.

Uncertainties

This forecast represents Cascade's best estimate about future events. At this time, several important factors make predicting future demand particularly difficult – continued economic growth, carbon legislation, building code changes, direct use campaigns, conservation, and long-term weather patterns. The range of scenarios presented here and in Chapter 9 encompass the full range of possibilities through econometric analysis. These forecasts were created after running through a matrix of different functional forms and economic indicators. The chosen indicators were selected because of their consistency in returning statistically valid results. While they may be the best results mathematically, they are not the sole and only determinants of demand. As a result, while Cascade believes that the numbers presented here are accurate and that the scenarios presented represent the full range of possibilities, there are and always will be uncertainties in forecasting future periods.

CASE: UG 390
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 700

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Mitchell Moore. I am a Senior Utility Analyst employed in the Energy Economic Analysis Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/701.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to address Cascade Natural Gas Corporation's (Cascade or Company) Test Year expense for the following issues: General Plant Maintenance; Employee Benefits; and Insurance. I do not recommend any adjustments.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/702, which contains Company responses to Staff data requests.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. GENERAL PLANT MAINTENANCE

Q. What is General Plant Maintenance?

A. These expenses, booked to FERC account 935, refer to labor, materials and expenses associated with the maintenance of general property such as building facilities, office furniture and equipment and communications equipment.

Q. What does Cascade propose for General Plant Maintenance in this proceeding?

A. The Company includes $10,544 in the Test Year for non-labor General Plant Maintenance, a slight increase that represents an inflation adjustment of 1.8 percent over the 2019 Base Year.[1]

Q. Please describe your review and analysis of Cascade's Plant Maintenance Expense.

A. Staff first reviewed General Plant Maintenance expenses for the historical calendar years of 2017, 2018, and 2019. This review included looking at trends, transactional details, and adjustments proposed by Cascade.

Staff initially looked at the annual increase in non-labor expenses for the past three years to determine whether the proposed increase in the Test Year is consistent with historical expenses. Staff also reviewed transaction details from the Base Year expense to ensure actual expenditures are justifiable for normal utility operations.

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[1] See CNGC/300, Peters/4.

Q. What does Staff conclude from its review?

A. Staff concludes that Cascade's proposed General Plant Maintenance expense is barely above its 3-year average for the preceding years of 2017, 2018, and 2019, and below the amount that Staff would allow under its normal practice of escalating the three-year average by the all-urban CPI. In reviewing individual transaction detail from the Base Year, Staff did not find any expense that would not be eligible for inclusion in base rates. Therefore, Staff concludes that Cascade's proposed expense for the Test Year is reasonable. I do not recommend any adjustment.

ISSUE 2. EMPLOYEE BENEFITS

Q. Please describe the Company's request regarding medical, dental, vision, and other employee benefits.

A. The Company has requested approximately $1.74 million in Test Year expenses relating to medical, dental, and other employee benefits on an Oregon-allocated basis.[2] In addition to health insurance, this cost includes such forms of compensation as long-term disability benefits, family leave, and a 401k matching program. The expense includes costs for both bargaining (union) and non-bargaining (non-union) employees.

Medical Benefit plan premiums are shared between the Company and the employees. In prior years the Company shared medical premium costs with employees at a ratio of 80/20 (i.e. employees pay 20 percent of premium costs and the Company pays 80 percent). For 2020 the Company eliminated its traditional health care plan options and offered only high-deductible medical plans to its employees. In doing so, it reduced the employees' share of the premium to three to eight percent, depending on the tier and plan chosen. The Company's request represents a slight decrease in employee benefits expense from $1.75 million in the 2019 Base Year to $1.74 million in the 2020 Test Year.[3]

Q. Please describe the analysis performed by Staff.

[2] See Exhibit Staff/702, Moore/1, Company response to Staff DR No. 87.
[3] See Exhibit Staff/702, Moore/2, Company response to Staff DR No. 58.

A. Staff performed a trend analysis, looking at the year-over-year increase to benefits. For medical costs, Staff compared those to national average costs as reported by the Kaiser Foundation benefits survey.

Cascade's medical benefit costs for 2020 are approximately $6,012 for a single employee and $18,876 for family coverage. As a comparison, the national average healthcare premiums as determined by the Kaiser Foundation are broken down by single and family levels of coverage. National average healthcare premiums in 2019 were $7,188 for single coverage and $20,576 for family coverage.[4]

In comparing the rate of increase in national average family premium costs with Cascade's, Staff finds Cascade's medical benefits costs appear to be generally below the national average. National average costs rose 3.4 percent in 2017, 4.5 percent in 2018, and 4.9 percent in 2019. In contrast, Cascade's medical benefit costs show a slight decrease from 2019 to 2020. Accordingly, I have no recommended adjustment for employee benefits.

[4] https://www.kff.org/health-costs/report/2019-employer-health-benefits-survey/

ISSUE 3. INSURANCE

Q. Please describe how Staff reviewed the Company's insurance and risks.

A. Staff reviewed the Company's responses to SDRs 057, 058, which set forth the Company's transaction summaries for Non-Labor costs recorded in all FERC Accounts for the Base Year, and 067-075, which include information regarding the Company's insurance coverage. Staff also looked at individual policies and term sheets and reviewed prior years' expenditures.

Staff noted with respect to Property and Casualty insurance coverage that the Company's expenditures decreased in the Test Year to $21,259, down from $27,405 in the Base Year. The Test Year expense is also slightly lower than the $22,000 average of the three preceding years.

For Injuries and Damages expense, the Test Year expense of $390,683 is about 17 percent higher than its Base Year expense of $334,701. However, the Base Year expense appears abnormally low. The three-year average of this expense from 2017-2019 is $407,012.

The Company also included $11,585 in Oregon-allocated Director's and Officer's (D&O) insurance in the Test Year, the result of removing 50 percent of this expense from the Test Year.[5]

Q. What is the purpose of D&O Insurance?

A. D&O insurance provides liability coverage to company officers and managers to protect them from claims that may arise from the decisions and actions

[5] See CNG/304, column (b).

taken within the scope of their duties. D&O insurance is usually purchased in "layers" to spread risk among different insurers. To acquire adequate coverage limits, diversify exposure, and reduce risk, an insurance structure is assembled where the primary insurer provides specific coverage terms and capacity limits, but less than the total needed. Additional insurers provide supplemental capacity limits that are in addition to the primary layer while still following the basic terms and conditions of the primary layer.

Q. Why does Cascade remove 50 percent of its D&O insurance premiums?

A. Staff typically recommends this adjustment as being consistent with prior Commission decisions. In Docket No. UE 197, Staff proposed that customers and ratepayers share the cost of D&O liability insurance. The Commission agreed that the cost of D&O liability insurance should be shared between ratepayers and shareholders.

> We concur with Staff that the cost of D&O insurance should be shared equally between shareholders and ratepayers to properly reflect the benefits and burdens of that expense. We eliminate 50 percent of the D&O insurance as a shareholder cost.[6]

In that case, the Commission found Staff's argument compelling that customers who have no say in electing or appointing utility directors or officers should not be held financially responsible for covering 100 percent of the insurance costs to cover against business decisions or improprieties by management that result in lawsuits.[7] This methodology has been followed by

[6] *In re Portland General Electric Company*, OPUC Docket No. UE 197, Order No. 09-020 at 19-20 (Jan. 22, 2009).
[7] Order No. 09-020 at 20.

Staff in subsequent dockets in both electric and natural gas utility general rate cases. Cascade's filing is consistent with Commission practice of removing 50 percent of all layers of D&O insurance from the Test Year expense.

Q. Please explain the other types of insurance that were reviewed.

A. Staff also reviewed property insurance, liability insurance, terrorism insurance, workers' compensation insurance, and other risk management insurance.

Q. Is Staff proposing an adjustment involving any of these types of insurances?

A. No. In reviewing the premiums paid for each of the different types of insurance, Staff concluded the Company's decision to carry these types of insurance coverage is prudent and that the insurance premiums appear reasonable as they have fluctuated only slightly from year-to-year. Because of the competitive nature of the insurance industry, it is Staff's position that premiums paid to protect the utility, and ultimately ratepayers, from high dollar casualty losses represents is a prudent business decision and that no adjustment is necessary.

Q. Does Staff propose an adjustment to non-D&O insurance expense?

A. No. Staff does not propose adjusting insurance expense.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 390
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 701

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME:	Mitchell Moore
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Rates, Finance and Audit Division
ADDRESS:	201 High Street SE. Suite 100 Salem Oregon 97301-3612
EDUCATION:	Bachelor of Arts, Journalism and Political Science University of Hawaii at Manoa
EXPERIENCE:	I have been employed by the Public Utility Commission of Oregon since 2009, with my current position being a Senior Utility Analyst in the utility program's Energy Rates, Finance and Audit division. I have provided expert witness testimony on a number of general rate case dockets, including: UE 294, UE 319, UE 335, UG 288, UG 305, UG 325, UG 344, UG 347, UG 366, and UG 388. My prior position at the Commission was as a Senior Telecommunications Analyst, where my assignments included reviewing carrier interconnection agreements, wholesale service quality, and resolution of carrier-to-carrier complaints. Prior to my utility regulatory career, I worked with AT&T as a loop electronics coordinator, designing and implementing high-speed broadband and fiber optic services in Los Angeles. I have also worked as an outside plant design engineer with Qwest Corporation, and I spent several years as a newspaper reporter with the Honolulu Star-Bulletin.

CASE: UG 390
WITNESS: MITCHELL MOORE

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 702

Exhibits in Support
Of Opening Testimony

July 30, 2020

CNG Response to Staff DR No. 87

FERC	January 2020	Februrary 2020	Mar-20	April 2020	May 2020	June 2020	July 2020	August 2020	September 20	October 202	November	December 202	Total
924	1,707	1,705	1,746	1,761	1,759	1,769	1,778	1,731	1,759	1,725	1,713	2,107	21,259
925	32,898	30,887	32,868	32,435	32,167	32,307	34,325	34,099	32,552	32,710	31,770	31,667	390,683
926	157,566	130,540	141,444	146,056	141,897	148,597	154,348	141,171	147,223	145,592	137,925	145,237	1,737,595
935	1,919	1,866	7,728	365	3,483	262	1,752	2	2	902	-	119	18,401

Cascade Response to Staff DR No. 58

CASCADE NATURAL GAS CORPORATION						
STATE ALLOCATION OF INCOME & EXPENSES (withou		OBJECT	FERC ACCOUNTS	2019	2018	2017
935	Maintenance of General Plant	[5211.6999]	29350	10,286.65	8,166.28	12,561.02

CASE: UE 390
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 800

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Ming Peng. I am a Senior Econometrician (Utility Analyst 3) employed in the Energy Economic Analysis Program of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/801.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to discuss my review of the depreciation rates used to calculate the depreciation and amortization expenses and accumulated depreciation (depreciation reserve) in Cascade Natural Gas Corporation's (Cascade, CNGC or Company) revenue requirement for this rate case, as documented by the Company witness, Maryalice C. Peters, in CNGC/300. I also discuss my review of the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this rate case.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared Exhibit Staff/801, Witness Qualification Statement, and Exhibit Staff/802, Cascade's Responses to Staff Data Request (DR) Nos. 122-132.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. ANALYSIS OF DEPRECIATION FROM A RATEMAKING PERSPECTIVE

Q. What is depreciation?

A. "Depreciation" is defined by the National Association of Regulatory Utility Commissioners (NARUC) in relevant part as follows:

> As applied to the depreciable plant of utilities, the term depreciation means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes that are known to be in current operation, against which the company is not protected by insurance, and the effect of which can be forecast with reasonable accuracy. Among the causes to be considered are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirement of public authorities.[1]

The statement above defines "depreciation" from a valuation perspective. From an accounting perspective, "depreciation" is the allocation of the cost of fixed assets less net salvage to accounting periods, which is a capital recovery concept. From a ratemaking perspective, both the valuation (rate base) and accounting (capital recovery) concepts of deprecation are important.

Q. Do Oregon statutes address utility depreciation rates?

A. Yes. ORS 757.140(1), states in relevant part:

> Every public utility shall carry a proper and adequate depreciation account. The Public Utility Commission shall ascertain and determine the proper and adequate rates of depreciation of the several classes of property of each public utility. The rates shall be such as will provide the amounts required over and above the expenses of maintenance, to

[1] NARUC, *Public Utility Depreciation Practices*, p.318 (1996).

> keep such property in a state of efficiency corresponding to the progress of the industry. Each public utility shall conform its depreciation accounts to the rates so ascertained and determined by the commission. The commission may make changes in such rates of depreciation from time to time as the commission may find to be necessary.

Q. How are utility property depreciation rates determined?

A. To develop depreciation rates, it is necessary to estimate (1) the combination of survivor curve[2]-service life (Curve-Life) of utility property, and (2) the net salvage[3] (Gross Salvage – Cost of Removal) ratio. Based on these two fundamental depreciation parameters (and other required elements, such as asset value, asset remaining life, and depreciation method) the depreciation rates are derived.

Q. What is depreciation reserve?

A. Depreciation reserve is "[a]t a point in time, the total amount of recorded depreciation, retirements, gross salvage, cost of removal, and other adjustments."[4] Depreciation reserve is also called accumulated depreciation. The amount by which the asset is depreciated each year is deducted from the value of the asset at its rate base.

Q. What depreciation rates did Cascade use in its Test Year revenue requirement?

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[2] "Survivor curve" means a curve that shows the number of units or cost of a given group which is surviving in service at given ages. The survivor curves were developed by the Engineering Research Institute of Iowa State University. These curves are frequently referred to as "Iowa Curves."

[3] Net Salvage. The gross salvage of the property retired less the cost of removal. This will be negative, if the cost of removal exceeds the gross salvage.

[4] *Introduction to Depreciation for Public Utilities and Other Industries*, page 167, Edison Electric Institute, 2013.

A. The current depreciation rates for the Company were authorized by OPUC Order No. 15-315 in Docket No. UM 1727 on October 14, 2015, effective January 1, 2016.

Q. Has Cascade recently filed the depreciation study?

A. Yes. Cascade filed its most recent depreciation study on March 26, 2020, which is under review by the Commission in Docket No. UM 2073. Cascade requests the revised depreciation rates become effective January 1, 2021.

Q. Please summarize Staff's analysis and review methods for depreciation rates in UM 2073.

A. The annual depreciation rate is the ratio of plant costs, adjusted for net salvage value, allocated to a one-year period in accordance with a rational and consistent plan of allocation over the average service life of the property.

1) Estimating the Survivor Curves and Service Lives: I calculate Cascade's proposal by utilizing statistical modeling to run the Iowa Survivor Curve and projection life by FERC account.
2) Estimating the Net Salvage Rates: I calculate Cascade's studies to identify net salvage rates by utilizing the statistical methods of overall averages and rolling band analyses.

ISSUE 2. DEPRECIATION EFFECT ON REVENUE REQUIREMENT

Q. Please describe the depreciation effect on the revenue requirement of a utility.

A. In the traditional rate base rate-of-return environment, customer rates and utility costs are components of a utility's revenue requirement. NARUC, in its "Public Utility Depreciation Practices" manual on "Depreciation Expense and Its Effect on the Utility's Financial Performance – Revenue Requirement" states:

> Depreciation has a profound effect on the revenue requirement of a utility, and for many utilities, depreciation expense represents a large percentage of total operating expenses. In addition, deferred income taxes, rate base, and cost of capital are all affected by the depreciation practices of a utility.[5]

Q. What is the relationship between utility property depreciation and utility revenue requirement?

A. Under cost-of-service regulation, revenue requirement refers to the revenues the utility must earn to recover the cost of providing service and to earn a reasonable return on its investment. To compute the revenue requirement (RR), which is measured by cost-of-service, a basic formula is followed:[6]

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

Rate Base = Gross Plant – "Accumulated Depreciation" – Accumulated Deferred Income Taxes + Working Capital

[5] NARUC, *Public Utility Depreciation Practices*, p.195 (1996).
[6] Federal Energy Regulatory Commission, *Cost-of-Service Rates Manual*, pp. 6-7 (1999), available online at: **www.ferc.gov**/industries/gas/gen-info/**cost-of-service-manual**.doc.

In this formula, “depreciation” is one of the largest line items in the cost of service; therefore, “depreciation” is important as both an annual expense and as a reduction of rate base.

Q. Please explain how the depreciation expense and reserve are calculated.

A. In a general rate case filing, the depreciation expense and reserve can be calculated by the following three steps:

1. <u>Obtain Authorized Depreciation Rates.</u> Cascade’s recently filed Depreciation Rates are in UM 2073. Those depreciation rates will be used in the UG 390 general rate case to calculate the revenue requirement.

2. <u>Determine the Depreciation Expense.</u>

Depreciation Expense = (Authorized Depreciation Rates) x (Plant-in-Service)

This step uses the new OPUC-authorized depreciation rates multiplied by net plant.

3. <u>Determine the Accumulated Depreciation Reserve</u> in the rate base.

Accumulated depreciation is the cost of the investment in gross plant that is recovered through the cost-of-service as depreciation expense. Accordingly, the depreciation expense is accumulated and subtracted from the gross plant to reduce the remaining investment to be recovered. The remaining balance is the net book plant. The net book plant represents the portion of gross plant that is not depreciated.

Q. What were the depreciation and amortization expenses and reserve that the Company filed in its revenue requirement?

A. The depreciation and amortization expenses and accumulated depreciation reserve are listed in the Table1 below:

Table 1. Cascade Filed Depreciation Adjustment

	UG 390	2019	Summary	Adj. due to	Adj. due to	2020 Test Year
	CNGC	Results Per	Of	Depreciation%	Cap Addition	Adjusted
	Exh 301 - ROO Summary Sheet	Company Filing	Adjustments	increase	increase	Total
		(1)	(2)	(3)	(4)	(5)
	Operating Expenses					
17	Depreciation & Amortization	7,772,990	1,664,373	731,637	932,735	9,437,362
	Rate Base					
26	Total Accumulated Depreciation	-109,428,349	-9,437,362	-731,637	-8,705,725	-118,865,711

(1) The adjustment of Oregon depreciation and amortization expense by December 31, 2020, was $1.66 million from the 2019 balance (=$9.4 million - $7.8 million);

(2) The adjustment of Oregon accumulated depreciation and amortization expense by December 31, 2020, was $9.4 million from the 2019 balance (= (-$118.9 million) - (-109.4 million)).

The depreciation expense increase due to the increase of depreciation rate is $0.73 million; the depreciation expense increase due to the capital addition increase is $0.93 million.

The accumulated depreciation expense increase due to the increase of depreciation rate is $0.73 million; the accumulated depreciation expense increase due to the capital addition increase is $8.7 million.

To calculate its depreciation expense and reserve for this rate case (UG 390), Cascade used the proposed depreciation rates from UM 2073. Currently, Cascade's depreciation study in UM 2073 is under review by the Commission. Once the Commission approves the new depreciation rates after the settlement by the stipulating parties in UM 2073, the Company's calculated depreciation expenses will be updated by using the Commission-authorized depreciation rates in UM 2073.

Q. Do you propose any adjustments to depreciation expense and reserve for the revenue requirement in UG 390 at the present time?

A. I do not because the Company proposed depreciation rates are under review in UM 2073. Once those depreciation parameters are approved by the Commission, Staff will use those values for the purpose of making a final recommendation on depreciation expense and reserve.

ISSUE 3. REGULATORY CAPITALIZATION POLICY

Q. What is AFUDC?

A. AFUDC is Allowance for Funds Used During Construction and is defined as the cost of money used during construction. AFUDC is capitalized as part of Plant in Service.

Q. What is the purpose of this review?

A. The purpose of this review is to verify whether Cascade used the proper accounting treatment for capitalized interest, and to confirm that the formula utilized to calculate the annual AFUDC rate is consistent with Cascade's regulatory-approved AFUDC rate.

Q. What is the FERC AFUDC Capitalization Policy?

A. On March 18, 2010, in FERC Docket No. AI11-1-000, Accounting Release Number 5 (AR-5) (Revised), FERC:

> Revised its AFUDC accrual policy to allow natural gas pipeline companies to begin accruing AFUDC on construction projects when the following two conditions are met: (1) capital expenditures for the project have been incurred; and (2) activities that are necessary to get the construction project ready for its intended use are in progress (AFUDC policy conditions).

FERC also explained that, "AFUDC capitalization shall continue as long as these two conditions are present."[1]

Q. Have you reviewed CNGC's Utility Plant - capitalization policy?

A. Yes. I reviewed CNGC's capitalization policy from its response to Standard Data Request (SDR) No. 80. In response to SDR No. 80, the Company

[1] FERC Docket No. A11-1-000, Accounting Release Number 5 (AR-5) (Revised) Enclosure, p. 1.

provided detailed information about AFUDC and its accounting practices related to AFUDC contained in its Utility Group (UG) Capitalization Policy AD-106. On page 1, the policy states:

> This policy and procedure is intended to provide a consistent basis for determining which of the costs incurred related to utility plant additions, retirements, transfers, and betterments by each Company will be considered as capital assets and recorded as such in each Company's Continuing Property Records. The policy is designed to provide a consistent asset base to 1) calculate rates of return for ratemaking purposes and 2) for depreciation provisions and 3) support property values for insurance, income tax, and property tax purposes as well as provide guidelines as to the addition of costs thereto and retirement of costs therefrom.

On page 5, the policy states:

PROCEDURES

A. Capitalizable utility plant investments shall be recorded on each Company's books in accordance with generally accepted accounting principles and the FERG uniform system of accounts instructions.

B. Within each of the plant accounts and sub-plant accounts used by each Company are identified property units or units of property. Property units are those items of utility plant which, when retired, with or without replacement, are accounted for by crediting the original installed cost thereof to the utility plant account and sub-plant account in which it is included. Property unit codes for Montana-Dakota Utilities Co. (MDU) and Great Plains Natural Gas Co. (GPNG) are listed on the Accounting Department intranet website via the Property Unit Listing link.

Q. Is the Company's AFUDC capitalization policy consistent with FERC rules and regulatory guide?

A. Yes. After the review, I did not identify a deficiency in the Company's capitalization practices and therefore, I did not make any recommendations for corrective action to those practices.

ISSUE 4. FERC AFUDC REQUIREMENTS

Q. Please describe the FERC formulas for calculating AFUDC.

A. The FERC AFUDC rate formulas are set forth in Plant Instruction 3(17) in the FERC's Uniform System of Account Prescribed for Public Utilities and Licensees (18 C.F.R. Part 101). The FERC has prescribed two formulas for calculating maximum allowable AFUDC rates. One formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes. The second formula determines the maximum rate that can be used to capitalize an allowance for other funds (e.g., common equity) used for construction purposes. The rates derived from each formula, added together, provide the total maximum allowable rate that can be used to capitalize AFUDC.

Q. Have you reviewed the Company's calculation of its AFUDC rate?

A. Yes. I reviewed the Company's calculation of its AFUDC rates based on FERC's AFUDC rate formulas mentioned above.

Q. Please describe whether CNGC complied with guidance regarding the capitalization of assets based on FERC and OPUC regulations in this filing.

A. FERC has prescribed two formulas for calculating maximum allowable AFUDC rates.

<u>Debt</u>: One formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes.

<u>Common Equity</u>: The second formula determines the maximum rate that can be used to capitalize an allowance for other funds (e.g., common equity) used for construction purposes.

1. Allowance for Funds Used During Construction (AFUDC) is a generally accepted accounting principle whereby the cost of financing capital construction projects is added to the cost of the asset.
2. FERC AFUDC Rate Formula: Utility companies should use the FERC formula for AFUDC as defined in Title 18 CFR Part 101 Electric Plant Instruction 3(A)(17). The portion of the formula and elements applicable to utility for calculating the annual AFUDC rate are:

   Ai = s (S/W) + d (D/D+P+C) (1-S/W)

   Ai = Gross allowance for borrowed funds used during construction rate.

Staff Data Request No. 128 asked:

> Under FERC AFUDC Accounting, the formulas assume that short-term debt is the first source of construction funding. If the balance of short-term debt exceeds the average balance of CWIP, the total AFUDC rate is comprised of only an allowance for borrowed funds used during construction equal to the short-term debt rate. Were these the assumptions on which the Company's formulas are based?

CNGC responded:

Ai (Borrowed Funds) = s(S/W) + d(D/(D+P+C)) * (1-S/W)

> First, the company determines the percentage of CWIP that is financed by short term debt and multiplies it times the average short-term debt rate. The short-term debt rate is computed by dividing the 13-month short term debt costs by the 13-month average balance. Second, if CWIP exceeds short term debt, then using actual balances as of the end of the prior year, the company computes a long-term debt percentage and multiplies it times the long-term debt rate times the amount of CWIP not financed by short term debt. The long-term debt rate is computed by dividing the annual long-term debt costs by the actual prior year end balance of long-term debt outstanding. Lastly, the short-term debt rate is added to the long-term debt rate.

Ae (Other Funds) = (1-S/W) * [p(P/(D+P+C)) + c(C/(D+P+C))]

> When the average balance of CWIP exceeds the balance of short-term debt the company computes AFUDC Other Funds rate. First, the company determines the percentage of CWIP that is financed by equity. Second, using actual balances as of the end of the prior year, the company computes an equity percentage. Third, the company computes a weighted average authorized return on equity. Lastly, the company multiplies the CWIP percentage financed by equity times the equity percentage times the average authorized return on equity.

Staff Data Request No. 129 asked:

> If the average balance of CWIP exceeds the balance of short-term debt, the calculation assumes that the construction funding was not met by short term debt. How did the Company incorporate the different capital sources and cost rates to arrive at the total, debt, and other funds' maximum allowable AFUDC rates? Please elaborate with a narrative response.

CNGC responded:

> Yes, if the balance of short-term debt exceeds the average balance of CWIP, the total AFUDC rate is equal to the short-term debt effective rate as prescribed by the FERC accounting formula for AFUDC.

Along with these data responses, Cascade provided detailed calculations in Excel format, after which Staff verified the Company's AFUDC calculations.

Q. Is the Company's calculation of its AFUDC rates in a manner consistent with the FERC rules and regulatory guide?

A. Yes. In response to Staff DR Nos. 122-132, along with the Excel calculation files, CNGC demonstrated its calculations of its annual AFUDC rates. I reviewed Excel spreadsheet files with reference links and calculation formulas, and found that the Company's calculation of its AFUDC rates follow the FERC AFUDC rate formulas and accounting requirements.

Q. Does Staff consider the Company's calculation of its AFUDC rates to be consistent with FERC rules?

A. Yes. Staff reviewed Excel spreadsheet files with reference links and calculation formulas and found that the Company's calculation of its AFUDC rates follow the FERC AFUDC rate formulas without deviation. The calculations assume that short-term debt is the first source of construction funding. If construction funding requirements exceed the balance of short-term debt, the calculations assume the requirements are met proportionally from long-term debt, preferred stock (if any), and common equity.

The table below shows the Company's annual AFUDC rates and the variances to the authorized rate of return:

Year	Authorized Rate of Return	Annual AFUDC Rate	Variance
2016	7.468	6.39	-1.078
2017	7.284	6.04	-1.244
2018	7.284	5.84	-1.444
2019	7.270	4.21	-3.060
2020	7.270	3.18 (est)	-4.090
2021	TBD	2.54 (est)	TBD

Cascade's Annual AFUDC rates are within the authorized rate of returns and the calculations are consistent with regulatory guidance.

Q. Have you made adjustments to Cascade's AFUDC rate?

A. No. The Company's AFUDC policy and calculation is consistent with regulatory guidance. Staff found that the data and the calculations are based upon assumptions reflecting the operations and conditions that the company reasonably expected to be followed.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 390
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 801

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Econometrician
Energy Rates, Finance and Audit Division

ADDRESS: 201 High Street SE. Suite 100
Salem, OR. 97301

EDUCATION & TRAINING:
M.S. Applied Economics
University of Idaho, Moscow

B.S. Statistics
People's University of China, Beijing

CRRA Certified Rate of Return Analyst in 2002
Society of Utility and Regulatory Financial Analysts

Depreciation studies – the Society of
Depreciation Professionals

NARUC Annual Regulatory Studies Program
Michigan State University, East Lansing

350+ credit hours on 30+ topics trainings in public utility industry

EXPERIENCE: 1/11/1999 – Present, Public Utility Commission of Oregon

I have been employed by the Public Utility Commission of Oregon (Commission) for 21 years. My roles include:

Expert Witness, Case Manager, Principal Analyst, Econometrician, Economist, Utility Analyst, and Policy Analyst.
I have testified in various formal state hearings and performed numerous analyses including economic, financial, statistical, mathematical, marketing, and policy analyses in public utility industry.

Principal Analyst & Case Manager, Settlement Lead / Negotiator for Depreciation Ratemaking:
I have served as a Principal Analyst and Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) for past 12 years. In this role, I had a strong focus on Depreciation Rate Determination (fixed cost allocation, and capital recovery). I was also a Principal Analyst and

Case Manager for the determination of Energy Property Depreciation Rates (Oregon Revised Statute 757.140) during this time period.

In this position, I investigated, analyzed and calculated energy asset retirement cost & impact and power plant decommissioning cost & impact on customer rates. I reviewed, calculated, analyzed fixed asset depreciation and propose depreciation parameters for each of FERC accounts on Generation, Transmission, Distribution, General, and Coal Mining Plants. The energy sources I have worked on are Steam/Coal, Hydraulic, Natural Gas, Wind, Solar, and Geothermal.

My analyses of "Power-Plant-Shutdown" activities (accelerated plant retirement, and decommissioning cost recovery) include the following cases:

1. PGE closes Boardman Coal-fired plant (UM 1679 & UE 215).
2. PacifiCorp closes Carbon Coal Plant in Utah (UE 246).
3. Multi-state PacifiCorp Klamath Hydro Dam Removal Cost recovery for (1) J. C. Boyle Dam, (2) Copco 1 Dam, (3) Copco 2 Dam, and (4) Iron Gate Dam removal under the ORS 757.734 – Recovery of investment in Klamath River dams in OPUC UE 219.
4. Idaho Power Valmy Coal-fired power plant Shutdown (UE 316).
5. PGE Colstrip Coal-fired power plant Shutdown (UM 1809).

I conduct case investigation and analysis on Utility's filings, make rate adjustments, lead settlement negotiation, prepare testimony, and appear on behalf of the Commission. The energy companies I work with are: (1) PacifiCorp (serves 6 states), (2) PGE, (3) Northwest Natural Gas (NWN), (4) Idaho Power, (5) Avista Corp (Washington), and (6) Cascade Gas (CNG, Montana).

Lead Analyst and Case Manager on Financial Dockets:

Prior to my current position, I was a lead Analyst and Case Manager for cost of debt capital for nine years. I reviewed market risks, derivatives and hedging, debt issuance, and stock flotation. My analysis directly informed utility and energy policy.

I advised the Commission on over 60 financial dockets. The Commission incorporated all of my recommendations into final orders.

I was certified by the Society of Utility and Regulatory Financial Analysts, as a Certified Rate of Return Analyst in 2002.

Public Utility & Policy Analyst:

Rulemaking: I have formulated energy regulation rules for utility performance incentives and cost-of-service regulation.

Energy Utility Merger & Acquisition: I have testified in formal state hearings involving utility mergers & acquisitions. I conducted Acquisition

Premiums & Credit Risk Analysis and testified on behalf of the Commission in MidAmerican Energy Company's application to purchase PacifiCorp. I also reviewed Scottish Power's earlier purchase of PacifiCorp, and PGE's emergence from Enron after the Enron bankruptcy.

Integrated Resource Planning (IRP, Least Cost Planning): I provided comments on B2H, a 500-kV transmission power line to the Commission for the decision-making that including cost and benefit list, pros and cons list, alternatives, and the legal risks. As well as comments on utility's IRPs, such as total cost for power generation, power capacity (MW) replacement cost, avoided cost for free fuel, and emission trading cost.

Clean Energy – Dollar Impact on Customer Rates: I have analyzed and calculated the rate impact and comparative advantage of clean energy. I built the portfolio optimization models to analyze the coal-fired generating capacity replacement.

General Rate Cases: I participate in almost all UE, UG rate cases since began working for OPUC. Historically, my review included fuel prices forecasting, property sales, load forecasting, weather normalizations, cost of debt, and capital structures. Currently, my reviews are focused on depreciation and reserve, AFUDC Capitalization Policy.

Survey Sampling Design: Results of my statistical sampling design and sampling procedures are incorporated into my revenue requirement testimony in Commission Docket No. UM 1288.

Auditing, Interest Rate, Late Payment: I audited cost of capital and financial components. My survey report and analyses are published annually for Oregon (UM 779).

Survey for Market Competition & Economic Policy: I conducted and wrote the report on Telecommunications "Market Competition and Economic Policy Survey Analysis" for House Bill 2577. This report has been published on the OPUC web annually for 15 years.

Mentor in the ICER - International Confederation of Energy Regulators

I was selected to act as a mentor in the ICER (International Confederation of Energy Regulators) Women in Energy (ICER WIE) pilot mentoring program. My "Mentoring Topics" focus on Incentive Regulation; Rate and Economic Impacts of "Cost-of-Service" regulation in the U.S. and "Price-Cap Performance Based Regulation" in Europe; Cost of Capital, Energy Demand and Price Forecasting Modeling; Least Cost Planning; and Regulatory Policy, and Renewable Energy issues within regulated rate structures.

CASE: UG 390
WITNESS: MING PENG

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 802

Exhibits in Support
Of Opening Testimony

July 30, 2020

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 122

Date prepared: April 15, 2020

Preparer: Maryalice Peters

Contact: Chris Mickelson

Telephone: (509)-734-4549

122. Please insert data links to the Company's Excel work paper provided in this docket, and enable Staff to verify such data as (1) Plant Balance, (2) Depreciation Rates, (3) Depreciation Expense, (4) Depreciation Reserve, and (5) Oregon Allocation Factors, which are all tied to the Revenue Requirement Excel Model.

Response:

See spreadsheet OPUC-122 UG 390 - Peters MCP-WP1.xlsx

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 123

Date prepared: April 15, 2020

Preparer: Maryalice Peters

Contact: Chris Mickelson

Telephone: (509)-734-4549

123. In addition, please provide the calculations for, (1) links, (2) formulas, (3) references, (4) notes, and (5) term definitions to the following work papers:

   a. Revenue Requirements Model;

   b. Gross Plant;

   c. Depreciation and Amortization Expense link to the Depreciation Rates as used in this filing; and

   d. Accumulated Depreciation and Amortization.

Response:

a. See spreadsheet OPUC-122 UG 390 - Peters MCP-WP1.xlsx.

b. See tab Exh-2019 Plant Additions in OPUC-122 UG 390 - Peters MCP-WP1.xlsx.

c. Attached as "OPUC-123c.xlsx" is a copy of the referenced tab "CNG Depr Study Rate Comparison". Column B in the attached file is transferred to the "Depreciation Expense Adj" tab in UG 390 - Peters MCP-WP1.xlsx.

d. The depreciation rates shown in Column D in Peters Exhibit 305-2020 Plant Additions are the depreciation rates approved in UM 1727. As Cascade only has a pdf file of Order 15-315 the rates were manually inputted into Column D, so no link can be provided.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 123 Revised

Date prepared: May 19, 2020

Preparer: Maryalice Peters

Contact: Chris Mickelson

Telephone: (509)-734-4549

123. In addition, please provide the calculations for, (1) links, (2) formulas, (3) references, (4) notes, and (5) term definitions to the following work papers:

   a. Revenue Requirements Model;

   b. Gross Plant;

   c. Depreciation and Amortization Expense link to the Depreciation Rates as used in this filing; and

   d. Accumulated Depreciation and Amortization.

Response:

a. See spreadsheet OPUC-122 UG 390 - Peters MCP-WP1.xlsx.

b. See tab Exh-2019 Plant Additions in OPUC-122 UG 390 - Peters MCP-WP1.xlsx.

c. Attached as "OPUC-123c&d Revised.xlsx" is a copy of the referenced tab "CNG Depr Study Rate Comparison". Column B in the attached file is transferred to the "Depreciation Expense Adj" tab in UG 390 - Peters MCP-WP1.xlsx.

   The rates presented in column C of the Depr 1032 report tab are only the "Base" depreciation rate. See column G in tab CNG Group Depr, the rates tie between those two. Then also in that tab, the total depreciation rate including "Salvage" and "COR" rates in column M tie to the Order. Unfortunately, the Depr 1032 does not show the "Salvage" and "COR" rates, but it does use them in the total depreciation calculation.

d. Attached as "OPUC-123c&d Revised.xlsx"

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 124

Date prepared: April 23, 2020

Preparer: Kim Ukestad

Contact: Chris Mickelson

Telephone: (509)-734-4549

124. Please provide the Company's forecasted Accumulated (1) Depreciation and (2) Amortization. Please include detailed calculation links for accumulated depreciation/amortization, retirement, amortization, and others that will add up to total in the Company's Revenue Requirement Excel model.

Response:

See attached spreadsheet, OPUC-124 UG 390 – Peters MCP-WP1.xlsx, that was submitted with our initial filing.

To tie to the $9,437,362.44 –

- Base year amount of $7,772,989.64 – this could be supported by the 13-month depr expense file that was provided in February. There are no calculations in there as our depreciation is calculated by PowerPlan and that was an export from PowerPlan. To tie to this amount, It's the YTD 2019 amount excluding FERCS 392 and 396.
- Adjustments of $1,664,373
    - $731,637 – calculation of this amount comes from the Exh 305-2020 Plant Additions tab within the spreadsheet.
    - $932,735 comes from the depreciation expense adjustment tab. The plant balance and actual January depreciation are exports from PowerPlan. The remainder of the cells then have the formulas to calculate the difference due to the proposed new depreciation rates. Essentially the changeover base year depreciation is combination of the proposed depreciation rate increase and December plant additions which would have started depreciating in January (thus not included in base year).

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 125

Date prepared: 04/24/2020

Preparer: Isaac Myhrum

Contact: Chris Mickelson

Telephone: (509)-734-4549

125. Please provide:

a. The current Oregon authorized Weighted Average Cost of Capital (WACC);
b. The Company's weighted average cost of capital (WACC) data from 2015 through 2020;
c. Current Oregon Authorized Capital structure: Debt/Equity Ratio;
d. The Company's Capital structure: Debt/Equity Ratio from 2015 through 2020; and
e. The current Oregon Authorized Return on Equity.

Response:

a. Current Oregon authorized WACC: 7.270%[4]
b. WACC figures per Spring Earnings Reviews:
   a. 2015: 6.76%
   b. 2016: 6.87%
   c. 2017: 6.48%
   d. 2018: 6.57%
   e. 2019: 5.90%
   f. 2020: 4.68%[1]
c. Current Oregon Authorized Capital structure: 50% long term debt and 50% equity.[2]
d. Debt/Equity Ratio by year[3]:
   i. 2015: 53% / 47%
   ii. 2016: 52% /48%
   iii. 2017: 50.8% / 49.2%
   iv. 2018: 48.9% / 51.2%
   v. 2019: 45.3% / 54.7%
   vi. 2020: 49.8% / 50.2%
e. Current Oregon Authorized Return on Equity: 9.400% [4]

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1 Exhibit CNGC/301 Peters.
2 UG 347/Stipulating Parties/100, Parvinen-Gardner-Gehrke-Mullins/18.
3 Exhibit CNGC/101 Kivisto
4 UG 347/Order No. 19-088/8

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 126

Date prepared: 4/21/20

Preparer: Kevin Conwell

Contact: Chris Mickelson

Telephone: (509)-734-4549

126. Regarding AFUDC Accounting (Allowance for Funds Used During Construction-AFUDC, Construction Work-in-Progress-CWIP), please explain in detail whether the Company's calculation of its AFUDC rates comply with the FERC AFUDC rate formulas and accounting requirements.

Response:

The company's AFUDC calculation does comply with FERC AFUDC accounting. See attachment **OPUC-126 CNG AFUDC Calc Oct 19.pdf** for the Q4 calculation workpapers, in addition a narrative of the calculation was provided in the response to question OPUC data request No. 129.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 127

Date prepared: 4/27/20

Preparer: Tony Durado

Contact: Chris Mickelson

Telephone: (509)-734-4549

127. For AFUDC Accounting (Allowance for Funds Used Durring Construction-AFUDC, Construction Work-in-Progress-CWIP), please fill out the attached computational table Attachment A with calculation formulas for years from 2016 to 2021 individually. The tables should identify: A) the sources of funds, B) the amount or balance of such funds, C) the applicable cost rates for such funds, D) Construction Work-in-Progress CWIP, E) the relative weight that should be given to those sources of funds, and F) the derivation of the AFUDC rates.

Response:

See Attached: OPUC-127.xlsx

Cascade Natural Gas calculates AFUDC Rates on a Quarterly Basis, using a combination of actual and projected account balances. (Example: The Q3 rate calculation will use actual results through June 30, and projected account balances for Jul-Dec.) These AFUDC Rates are then applied to eligible CWIP projects for the next Quarter to properly capitalize AFUDC Debt & Equity. Not all projects are AFUDC eligible per the company's policy.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 128

Date prepared: 4/20/20

Preparer: Kevin Conwell

Contact: Chris Mickelson

Telephone: (509)-734-4549

128. Under FERC AFUDC Accounting, the formulas assume that short-term debt is the first source of construction funding. If the balance of short-term debt exceeds the average balance of CWIP, the total AFUDC rate is comprised of only an allowance for borrowed funds used during construction equal to the short-term debt rate. Were these the assumptions on which the Company's formulas are based?

Response:

Ai (Borrowed Funds) = s(S/W) + d(D/(D+P+C)) * (1-S/W)

First, the company determines the percentage of CWIP that is financed by short term debt and multiplies it times the average short-term debt rate. The short-term debt rate is computed by dividing the 13-month short term debt costs by the 13-month average balance. Second, if CWIP exceeds short term debt, then using actual balances as of the end of the prior year, the company computes a long-term debt percentage and multiples it times the long-term debt rate times the amount of CWIP not financed by short term debt. The long-term debt rate is computed by dividing the annual long-term debt costs by the actual prior year end balance of long-term debt outstanding. Lastly, the short-term debt rate is added to the long-term debt rate.

Ae (Other Funds) = (1-S/W) * [p(P/(D+P+C)) + c(C/(D+P+C))]

When the average balance of CWIP exceeds the balance of short-term debt the company computes AFUDC Other Funds rate. First, the company determines the percentage of CWIP that is financed by equity. Second, using actual balances as of the end of the prior year, the company computes an equity percentage. Third, the company computes a weighted average authorized return on equity. Lastly, the company multiplies the CWIP percentage financed by equity times the equity percentage times the average authorized return on equity.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 129

Date prepared: 4/21/20

Preparer: Kevin Conwell

Contact: Chris Mickelson

Telephone: (509)-734-4549

129. If the average balance of CWIP exceeds the balance of short-term debt, the calculation assumes that the construction funding was not met by short term debt. How did the Company incorporate the different capital sources and cost rates to arrive at the total, debt, and other funds' maximum allowable AFUDC rates? Please elaborate with a narrative response.

Response:

Yes, if the balance of short-term debt exceeds the average balance of CWIP, the total AFUDC rate is equal to the short-term debt effective rate as prescribed by the FERC accounting formula for AFUDC.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 130

Date prepared: 4/15/2020

Preparer: Judy Feiring

Contact: Chris Mickelson

Telephone: (509)-734-4549

130. Has the Company put its CWIP into the rate base for capital recovery?

Response:

No, the Company does not include CWIP in rate base.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 131

Date prepared: 4/17/2020

Preparer: Scott Wanner

Contact: Chris Mickelson

Telephone: (509)-734-4549

131. Please provide the CWIP/AFUDC information. Include:

a. Cascade's capitalized AFUDC including the total dollar amount for its projects in Excel worksheets, including all supporting explanations, notes, and calculations.

b. A list of Projects and Costs excluded from AFUDC Base and a list of Projects and Costs included in AFUDC Base in an Excel spreadsheet.

Response:

Please see attached spreadsheet OPUC - 131.xlsx.

CASCADE NATURAL GAS CORPORATION
Oregon Public Utility Commission
General Rate Case
UG 390

Request No. 132

Date prepared: 4/15/2020

Preparer: Judy Feiring

Contact: Chris Mickelson

Telephone: (509)-734-4549

132. If the company complies with FERC's requirement: "AFUDC accruals must cease once the facility being constructed has been tested and is ready for, or placed in, service", please explain.

Response:

It is the Company's policy and practice to stop accruing AFUDC in the month following the actual in-service date.

CASE: UG 390
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 900

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Paul Rossow. I am a Utility Analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/201.

Q. What is the purpose of your testimony?

A. The proposed adjustments I recommend are derived from review of multiple data responses, analysis of Cascade Natural Gas Corporation's (Cascade or CNG) 2019 Operation and Maintenance non-payroll transactions, and Staff dues and memberships policy.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following Staff Exhibits.

Staff/901	Witness Qualifications Statement
Staff/902	Adjustment Summary

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. MEMBERSHIPS AND DUES

Q. What is the Commission's historical treatment of memberships and subscriptions?

A. Staff policy is to recommend allowing in rates the following: Industry Research Organizations (e.g., Gas Technology Institute) – 100 percent, except where organizations perform redundant services; National and Regional Industry Trade Organizations (e.g., American Gas Association) – 75 percent, on the basis that certain activities are promotional or lobbying in nature or otherwise do not benefit ratepayers;[1] and Other Organizations – disallow all expenditures unless the utility can present a convincing argument to do otherwise.[2]

Q. Please provide a summary of the Company's proposal for memberships and dues.

A. Cascade's workpaper shows that Cascade started with the expense paid by the Company for memberships and dues across both its Washington and Oregon jurisdictions and then determined the Oregon share by direct assignment and allocation. Cascade then adjusted this amount (approximately $85,000) by removing 100 percent of a small share of the dues (approximately $8,909), and then removing 50 percent of the remainder ($38,265), for a total adjustment of ($47,174). Cascade's workpaper does not identify what dues are removed in their entirety. However, the workpaper provides a list of the dues

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[1] See e.g., *In re Cascade Natural Gas Compa*ny, Docket Nos. UF 3129 and 3094, Order No. 74-898, p. 27 (1974 WL 391913) ("Expenses for legislative activities should not be borne by ratepayers.").
[2] See *In re Pacific Power and Light Company*, Docket No. UF 3779, Order No. 82-606 (1982 WL 993422) ("unless convincing evidence is offered, contributions, memberships, and dues will be disallowed for ratemaking purposes.").

that are shared 50/50 between ratepayers and the Company. These dues are, for the most part, for gas associations, research organizations, and chambers of commerce or other business organizations.

Q. Please explain your analysis for memberships, subscriptions, clubs, and dues adjustment.

A. Staff analysis included the review of CNG's memberships and dues expenses recorded to FERC accounts 870 through 935 provided in electronic spreadsheet format by CNG in its 2019 membership and dues adjustment[3] and CNG's response to SDRs 57, 89, and 90, which are 2019 transactions for all FERC Operations and Maintenance (O&M) and Administrative and General (A&G) Accounts. Staff then searched for memberships and dues by using the G/L Account Descriptions and Explanations provided by CNG in its response to SDR 57. Staff sorted these expenses by G/L Account Descriptions and Explanation.

Q. Is Staff proposing a disallowance?

A. No. Cascade's removal of 50 percent of dues is not entirely consistent with the Commission's historical treatment of expense for memberships. However, Cascade's methodology does not obtain very different results than what would be obtained by Staff's methodology. In fact, Cascade's methodology appears to obtain more favorable results for Oregon ratepayers.

[3] Id.

ISSUE 2. MEALS AND ENTERTAINMENT AND MISCELLANEOUS OPERATIONS AND MAINTENANCE EXPENSES

Q. Please describe the operations and maintenance (O&M) expenses at issue.

A. The Federal Energy Regulatory Commission (FERC) has classified the FERC accounts Nos. 813 - 935 as O&M. Staff reviews these accounts for expenditures that are discretionary in nature, excessive, and that according to Commission policy should be disallowed or shared between customers and shareholders. For instance, these expenses include meals and entertainment (M&E), awards, gifts, travel, candy, coffee, flowers, and other similar miscellaneous expenses.

Q. Please provide a summary of the Company's filed proposal for O&M expenses.

A. Cascade proposes including approximately $32.1 million of operating expenses after escalation in the 2020 test year.

Q. Did the Cascade propose an adjustment for M&E, awards, gifts and similar discretionary expenditures?

A. Yes. Cascade performed an analysis for Non-Labor expenses throughout all FERC accounts for the Base Year. CNG's analysis for Non-Labor expenses resulted in the removal of certain miscellaneous administrative and general expenses in the amount of $6,454, to FERC account 921, for the Base Year.

Q. Please explain the Commission's historical treatment of O&M non-payroll discretionary expenses.

A. In Docket No. UE 197, the Commission adopted the principle that expenses for certain discretionary expenses should be shared equally by ratepayers and shareholders.[4] Accordingly, a 50 percent sharing of such expenses between customers and shareholders is routinely recommended by Staff. In addition, Staff recommends disallowance of O&M non-payroll expenses that are imprudent or excessive or do not benefit Oregon regulated utility operations at a transactional level.

Q. Please describe Staff's analysis of the company's proposal for O&M non-payroll expenses.

A. Staff reviewed CNG's response to SDR 57, filed on April 1, 2020,[5] to identify any O&M non-payroll discretionary expenses that appear to be excessive, without sufficient business purpose, and not related to the provision of safe and reliable energy to customers. In CNG's response to SDR 057, the Company provided its 2019 O&M non-payroll transactional expenses in Excel format. The accounting data includes a number of fields, including FERC accounts, transaction descriptions, explanations, currency amount, and general ledger account descriptions. From this spreadsheet, Staff created a workbook to aid in Staff's analysis of O&M non-payroll discretionary expenses. Staff filtered the data by transaction explanations and highlighted the results for each expense in a separate worksheet. The selected expenditure types were Production

[4] See Order No. 09-020, pp. 20-21.

[5] SDR No. 57 requested the Company to provide information for all non-payroll expenses recorded in all FERC accounts for the base year.

Expenses, Distribution, Customer Accounts, Customer Service, A&G, Income Taxes, and Office Supplies (MDUR 29210).

Staff reviewed the expenses to determine whether they benefit customers or are discretionary and should be shared between customers and shareholders according to Commission policy.[6] The Commission has historically agreed with Staff that such discretionary expenses are not required to provide safe and adequate service to customers. Additionally, Commission policy does not require ratepayers to support causes that they do not necessarily support.[7]

Items Staff found to have no benefit to customers, Staff excluded at 100 percent. Those expenses Staff believed benefitted both customers and shareholders, Staff disallowed at 50 percent. Once Staff determined the disallowance based on 2019 dollars, Staff escalated using consumer price index of 1.8 percent, to arrive at the test year adjustment.

Q. Would you please explain by expenditure type the basis for your adjustments?

A. Yes. For instance, within A&G Expenses, Staff noted transactions related to expenses described as, coffee, recognition, gifts, floral, appreciation,

[6] Examples of key words Staff used to search transactions included candy, gum, b-fast, bfast, dessert, party, balloon, bereavement, flower, meal, Christmas, floral, recognition, appreciation, food, award, going away, cake, birthday, b-day, snack, coffee, donut, doughnut, bowling, golf, blazer, ball, ticket, prize, gift, dinner, lunch, supper, breakfast, diner, restaurant, bfast, napkins, photo, xmas, flight, hotel, airfare, air fare, air, travel, parking, luggage, baggage, shuttle, motel, taxi, lodging, and airport.
[7] See OPUC Order Nos. 87-406 at 40-41, Order No. 91-186 at 16, and Order No. 09-020 at 20-21.

celebration, and softball that Staff recommended excluding 50 or 100 percent.

Staff then reviewed expenses recorded in G/L Account Descriptions titled Production Expense, Distribution, Customer Accounts, Customer Service, A&G, Income Taxes, Office Supplies, and found discretionary expenses like, meals, donations, sponsorships, and gift basket. Staff disallowed these at 50 percent and 100 percent.

Q. What was the result of Staff's review for these expenses?

A. After searching through O&M non-payroll 2019 Oregon base year expenses (totaling $3,263,427), Staff disallowed $158,690 of expense at 100 percent and $112,655 of expense at 50 percent for an adjustment of ($56,327). Escalating these amounts to 2020 test year results in a decrease to the Oregon test year expenses of $216,031.

Q. What is Staff's total adjustment?

A. Staff's total adjustment is a decrease of $216,031 for O&M non-payroll expenses.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 390
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 901

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME:	Paul Rossow
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Utility Analyst Energy Resources & Planning Division
ADDRESS:	201 High Street SE Suite 100 Salem OR 97302-1166
EDUCATION:	Professional Accounting and Computer Application Diplomas, Trend College of Business 1987
EXPERIENCE:	I have been employed with the Public Utility Commission of Oregon as a Utility Analyst since October of 2002. Current responsibilities include research issues relating to energy utilities. I have actively participated in regulatory rate case proceedings in Oregon, including UE 147, UE 167, UE 170, UE 179, UE 180, UE 197, UE 210, UE 213, UE 215, UE 217, UE 233, UE 246, UE 262, UE 263, UE 283, UE 335, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, UG 344, and UG 347. I have attended the Utility Rate School sponsored by the Committee on Water of the National Association of Regulatory Utility Commissioners in May of 2005 and the Institute of Public Utilities sponsored by the National Association of Regulatory Utility Commissioners at Michigan State University in August of 2005.

G/L Description	Total Oregon Expense	100% Disallowance	50% Disallowance	Total 50% Disallowance
Production Expense	50,516.23		4,180.69	2,090.35
Distribution	2,126,520.51		59,785.13	29,892.57
Customer Accounts	749,148.63		2,380.46	1,190.23
Customer Service	127,831.42		6,710.20	3,355.10
A&G		10,910.68	34,628.05	17,314.03
Income Taxes	52,409.57	147,779.46		
MDUR 29210	157,000.83		4,970.60	2,485.30
Total	3,263,427.19	158,690.14	112,655.13	56,327.57

2020 Escalation 1.8%	Total Disallowance
2,127.97	
30,430.63	
1,211.65	
3,415.49	
17,625.68	
2,530.04	
57,341.46	216,031.60

CASE: UG 390
WITNESS: PAUL ROSSOW

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 902

Exhibits in Support
Of Opening Testimony

July 30, 2020

Staff Exhibit 902
Adjustment Summary

Is

Filed in electronic format

CASE: UG 390
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1000

Opening Testimony

July 30, 2020

Q. Please state your name, occupation, and business address.

A. My name is Sabrinna Soldavini. I am a Senior Regulatory Analyst employed in the Energy Rates Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Please describe your educational background and work experience.

A. My witness qualification statement is found in Exhibit Staff/1001.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide Staff's recommendation on the issues of Other Operating Revenue and Affiliate & Jurisdictional Cost Allocations.

Q. Did you prepare an exhibit for this docket?

A. Yes. I prepared the following exhibits:

1. Staff/1002, CNG Response to Staff Data Requests;
2. Staff/1003, Cascade 2019 Affiliated Interest Report; and
3. Staff/1004, NARUC Cost Allocation Guidelines.

Q. How is your testimony organized?

A. My testimony is organized as follows:

ISSUE 1. OTHER OPERATING REVENUE

Q. What is other operating revenue in the context of this case?

A. For the purposes of Staff's review, other operating revenue is defined as the sum of the following accounts, 488 – Misc. Service Revenues, 493 – Rent from Gas Property, 494 – Interdepartmental Rents, and 495 – Other Gas Revenue.[1]

Q. How does other operating revenue in the context of this case?

A. Other operating revenue serves as an offset, or reduction to revenue requirement in a rate case, as the Company no longer needs to collect this amount through general rates.

Q. What level of other operating revenue has the Company included in the Base Year and Test Year in this case?

A. Cascade recorded approximately $238,000 in Base Year other operating revenue, and proposes to include the same level in the Test Year as it states that it would only increase other operating revenue in the Test Year for "known and measurable" increases to other revenue.[2] Staff understands this to mean that the Company believes there are no known measurable changes to other operating revenue in the Test Year.

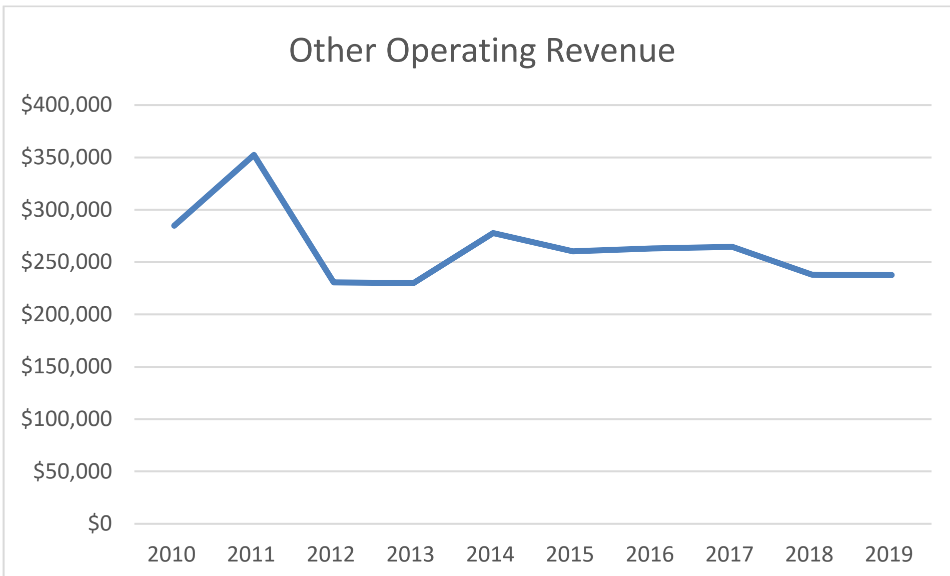
Q. Has Staff compared the Company's proposed Test Year other operating revenue level to historic actuals?

A. Yes. Staff asked for and received data on the level of other operating revenue received by the Company between the years 2010 through 2019. The data is

[1] Staff notes that Cascade also includes FERC accounts 496 – Provision for Rate Refund and 489 Revenue for Transportation of Gas of Others as Other Operating Revenue.
[2] Staff/1002, Soldavini/6. CNG Response to Staff Data Request 193.

displayed in Figure 1 below. As seen in this chart the level of other operating revenues has remained fairly consistent since 2015. Since 2010, other operating revenue ranged from a high of $352,415 in 2011 to a low of $229,937 in 2013, with an average of $263,940.[3]

Figure 1

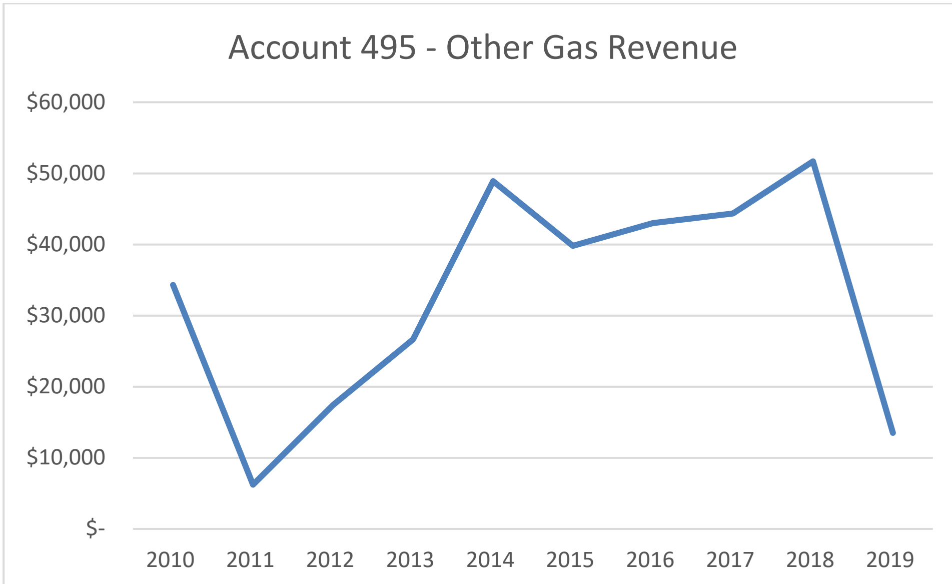


Q. Did Staff identify any subcategories of other operating revenue that appear abnormally low in the Base Year?

A. Yes. As seen in Figure 2 below, Account 495 – Other Gas Revenue, saw a large, unexplained decrease in 2019. Other Gas Revenue decreased from approximately $51,000 in 2018 to approximately $13,500 in 2019. The five-year average revenue for this account was $38,472.[4]

[3] Staff/1002, Soldavini/7. CNG Response to Staff Data Request 194.
[4] *Ibid.*

Figure 2



Q. Does Staff propose an adjustment to Other Operating Revenue?

A. Yes. To account for the abnormally low level of Account 495 revenue in 2019, Staff recommends an increase to other operating revenue of approximately $25,000 to bring Account 495 to its 5-year average of $38,472. This results in a Test Year other operating level of $263,940 and an approximately $25,000 reduction in Test Year revenue. Staff notes that this is also in line with the 10-year average of other operating revenue, equal to $263,940.[5]

[5] Staff/1002, Soldavini/6. CNG Response to Staff Data Request 194.

ISSUE 2. AFFILIATE & JURISDICTIONAL COST ALLOCATION

Q. Please explain the Commission's historical treatment of cost allocation among affiliates.

A. The Commission's historical treatment of affiliate cost allocation is pursuant to OAR 860-027-0048 (Allocation of Costs by an Energy Utility), which addresses the allocation of costs between an energy utility and its affiliates and how they should be recorded. OAR 860-027-0048 also states that an energy utility must keep a current Cost Allocation Manual (Allocation Manual) with detailed methodology on how costs are allocated between affiliates on file with the Commission and that the Allocation Manual shall be "filed yearly as an appendix to the Affiliated Interest Report required under OAR 860-027-0100".[6]

Staff analyzes the Allocation Manual for reasonableness and prudence in how costs are allocated between Cascade and its affiliates.[7] Staff compares methodologies used by the Company for compatibility with the National Association of Regulatory Utility Commissioners' (NARUC) Guidelines for Cost Allocations and Affiliate Transactions.[8]

Q. Please describe the services traded between Cascade and its affiliates.

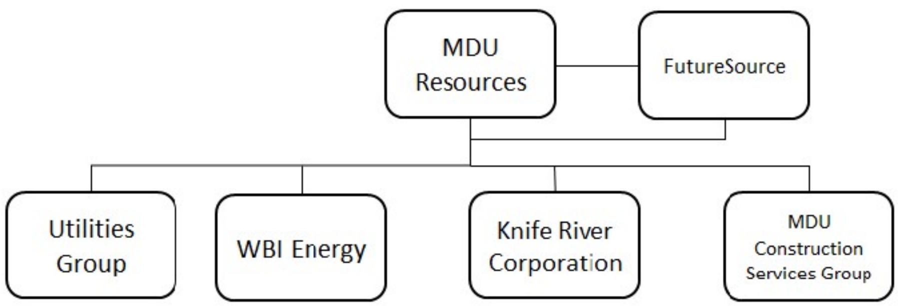
A. Cascade is a multi-state local natural gas distribution company (LDC) operating in Washington and Oregon. Cascade performs no unregulated operations. Cascade is owned by MDU Resources Group, Inc. (MDUR). The Commission

[6] *See* OAR 860-027-0048(6).
[7] Exhibit Staff/1003, RG 44(7) CNG Affiliated Interest Report for 2019.
[8] Exhibit Staff/1003.

authorized MDUR to purchase Cascade in 2007.[9] MDUR owns regulated and unregulated companies.

Cascade both allocates costs to, and is allocated costs from, its affiliates. Cascade provides services such as gas control and information technology (IT) to other MDUR operating companies. MDUR corporate staff provides payroll, procurement, enterprise technology, administrative and general services to Cascade. An organization chart is found in Figure 3 below.

Figure 3 Corporate Level Organization Chart



Q. How, generally, does Cascade allocate costs among its affiliates?

A. Cascade's cost allocation methodology is described in its Allocation Manual provided in Exhibit Staff/1003. Allocations to and from MDUR and its subsidiaries (including Cascade) are based on a variety of allocation factors. The allocation manual states, "the approach to allocating costs at each level is to directly assign costs when applicable and to allocate costs based on the function or driver of the cost."[10]

[9] Docket UM 1283, Order 07-221.
[10] Exhibit Staff/1003, Soldavini/21.

Q. What services does the parent, MDUR, offer to Cascade?

A. MDUR operates several departments that provide shared services to its subsidiaries. These departments include: Payroll Shared Services, Human Resources, Enterprise Information Technology (EIT), and Business Services.

Q. How are costs for these shared services allocated?

A. Cascade's Allocation Manual lays out in detail several methods for allocation of these services, in Exhibits I-VI. I will provide a few examples below.

Costs for payroll shared services are charged based on the number of employees paid. Enterprise information technology (EIT) provided by MDUR for its subsidiaries include several departments that are allocated using their own distinct factors. The customer relations group within EIT allocates costs based on a weighted average percentage of total devices for each company that are supported by customer relations as seen in Figure 4 below.[11] Cascade's allocation rates for EIT groups range from 5.98 percent in the operations group to 14.12 percent in the application services group within EIT.[12]

[11] Exhibit Staff/1003, Soldavini/40.
[12] Exhibit Staff/1003, Soldavini/39-41.

Figure 4

Customer Relations (965) – Enterprise charges for the customer relations group are invoiced using three weighted allocation factors. The factors are as follows:

1. Direct charge for employees working for a specific business
2. Number of computing devices supported by the help desk (90%)
3. Number of mobile devices supported by the help desk (10%)

The metric used to determine device counts is devices that have checked into active directory during a 60-day period in the summer of 2018 and active devices in MobileIron.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges			53.53%	46.47%						100%
Factor- 13.49%			7.22%	6.27%						13.49%
Computing Device Counts	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of Device Count	4.58%	18.53%	7.45%	9.56%	0.79%	4.52%	0.67%	27.59%	26.31%	100%
% of Device Factor- 77.86% (86.51% x 90%)	3.57%	14.42%	5.80%	7.44%	0.62%	3.52%	0.53%	21.48%	20.48%	77.86%
Mobile Device Counts	159	561	277	195	207			1,866	2,410	5,675
% of Device Count	2.80%	9.89%	4.88%	3.43%	3.65%			32.88%	42.47%	100%
% of Device Factor- 8.65% (86.51% x 10%)	0.24%	0.86%	0.42%	0.30%	0.32%			2.84%	3.67%	8.65%
Total weighted allocation factor	3.81%	15.28%	13.44%	14.01%	0.94%	3.52%	0.53%	24.32%	24.15%	100%

Definition of 965: This team is made up of help desk agents who support company owned devices and software.

Business services costs include costs for functions such as corporate governance, accounting and planning, legal, and human resources among others. These corporate overhead costs are allocated to MDUR's subsidiaries via a corporate allocation factor derived from a 12-month average capitalization period. Cascade's corporate allocation rate for 2019 is 14.9 percent.[13]

MDUR also operates several departments that serve all four utility companies (Montana-Dakota, Great Plains, Cascade Natural Gas Co., and Intermountain Gas Company). These departments are the Leadership Group, Customer Services, Information Technology and Communications, Operations & Engineering Services Group, Environmental, Safety & Technical Training, Business Development, Utility Group Controller, and Gas Supply.

Exhibit IV of the Allocation Manual outlines the various methods for how costs for these services are allocated. For example, according to this exhibit,

[13] Exhibit Staff/1003, Soldavini/34.

Cascade is allocated 26.5 percent of the costs of the gas supply department based on utility group meter counts and employee time studies. Customer service group payroll costs are allocated using customer counts, customer call time, cleared order count, credit to-do's, and email and web requests.[14]

Q. How is ownership of assets distributed and how are associated costs allocated?

A**.** Some assets, such as the General Office/Annex, utilized by Cascade are owned by MDUR subsidiaries. Likewise, some assets utilized by affiliates are owned by Cascade. For the costs of ownership and operating costs associated with owned assets, a revenue requirement is computed for the shared assets. The resulting revenue requirements are billed to the other MDUR companies as a monthly fee allocated based on the number of customers served by each utility.

Q. Does Staff agree that these allocation rates appear reasonable?

A**.** At this time, Staff agrees that the way these costs are allocated appears to be reasonable and based upon cost driving factors such as the number of customers, incremental activities, and employee time.

Q. Please explain the Commission's historical treatment of cost allocation among state jurisdictions.

A. Staff also reviews how the Company allocates costs between its two state jurisdictions: Oregon and Washington. Staff reviews applicable formulas and models to confirm Oregon is being allocated costs based on the actual burden

[14] Exhibit Staff/1003, Soldavini/44.

caused by the Oregon jurisdiction to ensure Oregon ratepayers are paying only their share of costs.

Q. How are costs allocated between the two state jurisdictions?

A. The Company operates in two state jurisdictions: Oregon and Washington. Costs are directly assigned to a jurisdiction when possible. When costs are shared between the two jurisdictions they are allocated between the two. The most common method of shared cost allocation between the state jurisdictions is to allocate costs based on the three-factor formula. The three-factor formula is a weighted average of the ratio of customers, the employee ratio, and the gross plant ratio. The three-factor formula assigned to the Oregon jurisdiction for the test year, as filed, is 24.95 percent of the costs shared between jurisdictions.[15]

[15] *See* Exhibit Staff/1002, Soldavini/1-4. Cascade Response to Staff Data Request No. 119.

Figure 5

Cascade Natural Gas Corporation State Allocation Formulas 2019			
	Washington	Oregon	Total
Customers	74.17%	25.83%	100.00%
Employees	73.73%	26.27%	100.00%
Gross Plant	77.25%	22.75%	100.00%
3-Factor Formula	75.05%	24.95%	100.00%

Q. Does Staff agree that this is a reasonable approach to cost allocation between the state jurisdictions?

A. Yes. Staff feels comfortable with the approach used for cost allocation between Washington and Oregon at this time. The three-factor formula that is used as the primary allocation method between the state jurisdictions complies with the NARUC principle that allocations should be made with respect to cost drivers.

Q. Please describe Staff's analysis of the Company's cost allocation methodology.

A. To determine whether or not the Company's cost allocation practices are reasonable, Staff first read through the Company's most recent Allocation Manual looking at each component listed therein to ensure they are based on cost drivers when possible. Staff reviewed how the Company allocates costs to its affiliates and how its affiliates allocate costs to the Company. Staff reviewed the information provided in response to data requests, as well as all cross charges to Cascade from affiliates.

To analyze the Company's state jurisdiction allocations, Staff reviewed the formulas and methods used in the Company's primary state allocation factor, the three-factor formula, for reasonableness and correctness. Staff also reviewed charges for verification that costs associated with activities not benefiting Oregon ratepayers were not erroneously allocated to Oregon.

Q. Does Staff propose an adjustment to the proposed test year?

A. Staff does not have an adjustment regarding cost allocation for opening testimony, but reserves the right to propose an adjustment based on other parties' testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 390
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1001

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATION STATEMENT

NAME:	Sabrinna Soldavini
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Regulatory Analyst Energy Rates, Finance, and Audit Division
ADDRESS:	201 High St. SE. Suite 100 Salem, OR 97301-3612
EDUCATION:	Master of Science, Agricultural Economics Purdue University, West Lafayette, Indiana Bachelor of Science, Economics University of Oregon, Eugene, Oregon

EXPERIENCE:

I have been employed by the Oregon Public Utility Commission (OPUC) since August 2018 in the Energy Rates, Finance, and Audit Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues. I have sponsored testimony before the OPUC in the following dockets: UE 350, UE 356, UE 358, UE 359, UE 374, UE 374, UE 377, UG 347, UG 366, UG 388, UG 389, and UG 390 (Pending).

Prior to working for the Commission I was employed as a consulting analyst for MGT Consulting, primarily working on projects to assist large public school districts prepare for bond proposals through budget analysis and statistical modelling/projections of student and demographic data.
From June 2015 – June 2017, I was a Research Assistant at Purdue University where I conducted research on the economic feasibility of biofuel feedstocks. Additionally, I have experience working in data analysis and program coordination within the technology sector.

CASE: UG 390
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1002

Exhibits in Support
Of Opening Testimony

July 30, 2020

Request No. 119

Date prepared: 3/16/2020

Preparer: Pamela Archer

Contact: Chris Mickelson

Telephone: (509)-734-4549

119. Please provide in electronic spreadsheet format, a copy of the Company's jurisdictional separation model or study applicable to the Test Year, with values for the Test Year, for the calendar year in which the Test Year begins (if different from the Test Year), and for each of the two calendar years preceding the calendar year in which the Test year begins.

Response:

See attached Excel worksheet SDR-119.xlsx

Cascade Natural Gas Corportation
CY 2020 Allocation Factors

Cascade Natural Gas Corporation
State Allocation Formulas
2019

	Washington	Oregon	Total
Customers	74.17%	25.83%	100.00%
Employees	73.73%	26.27%	100.00%
Gross Plant	77.25%	22.75%	100.00%
3-Factor Formula	75.05%	24.95%	100.00%
Rate Base Ratio	76.84%	23.16%	100.00%

Cascade Natural Gas Corporation
Average No. of Employees
2019

Source: Customers Per Employee report

Mo-Yr	Washington District Employees (1)	Oregon District Employees (1)	
Dec-18	174	65	
Jan-19	172	65	
Feb-19	171	62	
Mar-19	177	61	
Apr-19	171	63	
May-19	173	63	
Jun-19	180	63	
Jul-19	173	60	
Aug-19	168	58	
Sep-19	166	58	
Oct-19	165	57	
Nov-19	166	58	
Dec-19	165	61	
	2,221	794	
Average of Monthly Averages	171	61	232
Percentage	73.73%	26.27%	100.00%

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2019

	Washington Incl. CCNC	Oregon Incl. CCNC	Total
Avg. of Mo. Avg.s	835867892	246123480	1,081,991,372
Percentage	77.25%	22.75%	100.00%

Cascade Natural Gas Corporation
Average Number of Customers
2019

	Average No. of Customers	Percentage
Washington	218,811	74.17%
Oregon	76,203	25.83%
Total	295,014	100.00%

Cascade Natural Gas Corporation
Rate Base Ratio
2019

The following percentages are used for allocating interest on debt:

	2019 Average Rate Base	Plant Formula
Washington	375,260,464	76.84%
Oregon	113,099,946	23.16%
	488,360,410	100.00%

2018	WA	OR	Total
Jan.	218132	75771	293903
Feb.	218540	75922	294462
Mar.	218575	76043	294618
Apr.	218334	76044	294378
May	218053	75968	294021
June	217826	75848	293674
July	217678	75798	293476
Aug.	217702	75783	293485
Sept.	218366	76066	294432
Oct.	220143	76783	296926
Nov.	220903	77101	298004
Dec.	221483	77307	298790
Average	218811.25	76202.83333	

Cascade Natural Gas Corportation
CY 2019 Allocation Factors

Cascade Natural Gas Corporation
State Allocation Formulas
2018

	Washington	Oregon	Total
Customers	74.30%	25.70%	100.00%
Employees	73.72%	26.28%	100.00%
Gross Plant	77.49%	22.51%	100.00%
3-Factor Formula	75.17%	24.83%	100.00%
Rate Base Ratio	75.54%	24.46%	100.00%

Cascade Natural Gas Corporation
Average No. of Employees
2018

Source: Customers Per Employee report

	Mo-Yr	Washington District Employees (1)	Oregon District Employees (1)	
	Dec-17	172	62	
	Jan-18	173	62	
	Feb-18	173	60	
	Mar-18	173	60	
	Apr-18	172	60	
	May-18	172	59	
	Jun-18	179	62	
	Jul-18	179	63	
	Aug-18	177	63	
	Sep-18	169	63	
	Oct-18	170	63	
	Nov-18	176	65	
	Dec-18	174	65	
		2,259	807	
Average of Monthly Averages		174	62	236
	Percentage	73.72%	26.28%	100.00%

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2018

	Washington Incl. CCNC	Oregon Incl. CCNC	Total
Avg. of Mo. Avg.s	780275999	226716210	1,006,992,209
Percentage	77.49%	22.51%	100.00%

Cascade Natural Gas Corporation
Average Number of Customers
2018

	Average No. of Customers	Percentage
Washington	214,996	74.30%
Oregon	74,377	25.70%
Total	289,373	100.00%

Cascade Natural Gas Corporation
Rate Base Ratio
2018

The following percentages are used for allocating interest on debt:

	2018 Average Rate Base	Plant Formula
Washington	302,980,258	75.54%
Oregon	98,079,245	24.46%
	401,059,503	100.00%

2018	WA	OR	Total
Jan.	214279	73776	288055
Feb.	214536	73971	288507
Mar.	214618	74033	288651
Apr.	214470	74085	288555
May	214194	74048	288242
June	214055	74097	288152
July	213963	74066	288029
Aug.	214061	74072	288133
Sept.	214655	74412	289067
Oct.	216130	74958	291088
Nov.	217223	75393	292616
Dec.	217767	75609	293376
Average	214995.9167	74376.66667	

Cascade Natural Gas Corportation
CY 2018 Allocation Factors

Cascade Natural Gas Corporation
State Allocation Formulas
2017

	Washington	Oregon	Total
Customers	74.49%	25.51%	100.00%
Employees	72.58%	27.42%	100.00%
Gross Plant	77.49%	22.51%	100.00%
3-Factor Formula	74.85%	25.15%	100.00%
Rate Base Ratio	77.03%	22.97%	100.00%

Cascade Natural Gas Corporation
Average No. of Employees
2017

Source: Customers Per Employee report

Mo-Yr	Washington District Employees (1)	Oregon District Employees (1)	
Dec-16	186	67	
Jan-17	170	64	
Feb-17	171	65	
Mar-17	169	65	
Apr-17	170	65	
May-17	172	65	
Jun-17	174	69	
Jul-17	173	68	
Aug-17	177	68	
Sep-17	171	64	
Oct-17	173	64	
Nov-17	172	61	
Dec-17	172	62	
	2,250	847	
Average of Monthly Averages	173	65	238
Percentage	72.58%	27.42%	100.00%

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2017

	Washington Incl. CCNC	Oregon Incl. CCNC	Total
Avg. of Mo. Avg.s	721672786	209695352	931,368,138
Percentage	77.49%	22.51%	100.00%

Cascade Natural Gas Corporation
Average Number of Customers
2017

	Average No. of Customers	Percentage
Washington	211,165	74.49%
Oregon	72,304	25.51%
Total	283,469	100.00%

Cascade Natural Gas Corporation
Rate Base Ratio
2017

The following percentages are used for allocating interest on debt:

	2017 Average Rate Base	Plant Formula
Washington	290,338,758	77.03%
Oregon	86,572,946	22.97%
	376,911,704	100.00%

2017	WA	OR	Total
Jan.	210796	71933	282729
Feb.	210983	72009	282992
Mar.	211065	72057	283122
Apr.	211041	72101	283142
May	210636	72001	282637
June	210111	71882	281993
July	209873	71847	281720
Aug.	209751	71902	281653
Sept.	210539	72266	282805
Oct.	212041	72811	284852
Nov.	213194	73260	286454
Dec.	213945	73582	287527
Average	211164.5833	72304.25	

Request No. 120

Date prepared: March 2, 2020

Preparer: Pamela Archer

Contact: Chris Mickelson

Telephone: (509)-734-4549

120. Please provide in electronic spreadsheet format, the allocation of shared costs between the Company and subsidiaries or partners applicable to the Test Year, for the calendar year in which the Test Year begins (if different from the Test Year), and for each of the two calendar years preceding the calendar year in which the Test year begins. Please provide such data by FERC account. If the Company does not allocate shared costs, please explain why not.

Response:

The Company does not have this information in electronic spreadsheet format. Attached is the confidential methodology, Confidential OPUC-121.pdf, applied to shared services. The actual results are contained in the annual Result of Operations Report.

Due Date: June 12, 2020

Request No. 193

Date prepared: 6/4/2020

Preparer: Chris Mickelson

Contact: Chris Mickelson

Telephone: (509)-734-4549

193. Please provide a narrative description of how the Company calculates its level of Other Operating Revenue. Please also provide a narrative description of why the Company is proposing no adjustment to the level of Other Operating Revenue between the Base Year and Test Year.

Response:

Cascade already provided a response in Data Request No. 172 that asked a similar question as to explain why no proposed adjustment to other operating revenues between the base and test year. Nonetheless, Cascade will restate and elaborate the Company's position for convenience, Cascade would not adjust other operating revenues unless known and measurable since this represent various other types of revenues realized that do not result from the direct sale of natural gas, such as, miscellaneous service, disconnects, late fees, field visits, rent from property, or transport.

Cascade did leave a placeholder within our rate case for an anticipated contract agreement, column (p) entitled "Special Contracts" within our revenue requirement, to be filed in an upcoming application possibly during this proceeding between the Company and a firm distribution transportation service customer, which would adjust the revenues other than gas sales.

Also, due to COVID-19 and the suspension of disconnects and late fees on outstanding balances, Cascade is losing upwards of $14,000 per month on average of other operating revenues, which by the time these practices are reinstated could result in up to $100,000 or more in loss other operating revenues (Oregon only). It is possible that other operating revenues are being adjusted downwards due to COVID-19, but these examples are not straightforward to quantify and extract. In addition, Cascade currently has an accounting petition for deferral of COVID-19 related costs.

Request No. 194

Date prepared: 6/03/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

194. For calendar years 2010 through 2019, inclusive, please provide the value of other operating revenues, and for each year, identify the major components included in other operating revenues.

Response:

See attached Excel Spreadsheet OPUC.194.xlsx

CASCADE NATURAL GAS CORPORATION		OBJECT	FERC ACCOUNTS	2019	2018	2017	2016	2015	2014	2013	2012	2011	2010
OTHER OPERATING REVENUE													
4880	Misc Service Revenues	4880	*	(169,983.69)	(146,469.86)	(182,796.87)	(177,915.09)	(185,988.33)	(193,624.08)	(169,572.64)	(202,346.98)	(333,196.97)	(237,000.82)
4880	Misc Service Revenues	*	2488	-	-	-	0.01	-	-	110.47	1,522.35	57,192.72	160,174.38
4890	Rev. from Transp of Gas of Others	489*	*	(4,432,276.33)	(4,125,678.99)	(4,114,883.47)	(4,044,719.50)	(3,992,732.59)	(4,029,533.76)	(3,966,439.75)	(4,012,256.65)	(3,913,605.70)	(3,795,268.96)
4930	Rent from Gas Property	4930	*	(12,000.00)	(11,000.00)	(12,000.00)	(12,000.00)	(9,728.10)	(11,000.00)	(11,049.10)	(11,000.00)	(13,000.00)	(13,435.00)
4940	Interdepartmental Rents	4940	*	(42,262.67)	(28,749.48)	(25,558.08)	(30,052.92)	(24,915.60)	(24,264.01)	(22,682.01)	-	-	-
4950	Other Gas Revenue	4950	*	(13,491.77)	(51,691.85)	(44,349.33)	(43,000.53)	(39,827.92)	(48,891.15)	(26,633.44)	(17,401.94)	(6,218.95)	(34,305.75)
4962	Provision for Rate Refund	4962	*	268,153.46	1,558,019.97	-	-	-	-	-	-	-	-
				(4,401,861.00)	**(2,805,570.21)**	**(4,379,587.75)**	**(4,307,688.03)**	**(4,253,192.54)**	**(4,307,313.00)**	**(4,196,266.47)**	**(4,241,483.22)**	**(4,208,828.90)**	**(3,919,836.15)**

CASCADE NATURAL GAS CORPORATION									
		OBJECT	FERC ACCOUNTS	2019	2018	2017	2016	2015	2014
OTHER OPERATING REVENUE									
4880	Misc Service Revenues	4880	*	(169,983.69)	(146,469.86)	(182,796.87)	(177,915.09)	(185,988.33)	(193,624.08)
4880	Misc Service Revenues	*	2488	-	-	-	0.01	-	-
4890	Rev. from Transp of Gas of Others	489*	*	(4,432,276.33)	(4,125,678.99)	(4,114,883.47)	(4,044,719.50)	(3,992,732.59)	(4,029,533.76)
4930	Rent from Gas Property	4930	*	(12,000.00)	(11,000.00)	(12,000.00)	(12,000.00)	(9,728.10)	(11,000.00)
4940	Interdepartmental Rents	4940	*	(42,262.67)	(28,749.48)	(25,558.08)	(30,052.92)	(24,915.60)	(24,264.01)
4950	Other Gas Revenue	4950	*	(13,491.77)	(51,691.85)	(44,349.33)	(43,000.53)	(39,827.92)	(48,891.15)
4962	Provision for Rate Refund	4962	*	268,153.46	1,558,019.97	-	-	-	-

Request No. 257

Date prepared: 7/01/2020

Preparer: Chris Ryan

Contact: Chris Mickelson

Telephone: (509)-734-4549

257. Please refer to the Company's response to Staff Data Request 194.
    a. Please provide a narrative description of the categories of revenues charged to Account 4950 – Other Gas Revenue.
    b. Please explain why Account 4950 – Other Gas Revenue fell to just $13,491 in 2019.
    c. Please provide a narrative description of the categories of revenues charged to Account 4930 – Rent from Gas Property.
    d. Please explain why Account 4930 – Rent from Gas Property saw a significant increase in revenue in 2019 as compared with prior years.

Response:

a) 4950 is used for sales to a non-gas customer, consisting of misc. material sales, service line modifications, 3rd party damages, and misc. other charges.
b) Less charges of (a) in 2019.
c) Rental of gas property for a coffee stand.
d) Looking at the data, I don't see a significant increase for 4930.

CASE: UG 390
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1003

Exhibits in Support
Of Opening Testimony

July 30, 2020

Oregon Public Utility Commission

e-FILING REPORT COVER SHEET

COMPANY NAME: Cascade Natural Gas Corporation

DOES REPORT CONTAIN CONFIDENTIAL INFORMATION? ■ No ☐ Yes If yes, submit a redacted public version (or a cover letter) by email. Submit the confidential information as directed in OAR 860-001-0070 or the terms of an applicable protective order.

Select report type: ☐ RE (Electric) ■ RG (Gas) ☐ RW (Water) ☐ RT (Telecommunications)
☐ RO (Other, for example, industry safety information)

Did you previously file a similar report? ☐ No ■ Yes, report docket number: RG-44(7)

Report is required by: ■ OAR 860-027-0100 and 860-027-0048(6)
☐ Statute
☐ Order
Note: A one-time submission required by an order is a compliance filing and not a report (file compliance in the applicable docket)
☐ Other
(For example, federal regulations, or requested by Staff)

Is this report associated with a specific docket/case? ☐ No ■ Yes, docket number: RG-44(8)

List Key Words for this report. We use these to improve search results.

Affiliated Interest, Cost Allocation Manual, Cascade Natural Gas Corporation

Send the completed Cover Sheet and the Report in an email addressed to PUC.FilingCenter@state.or.us

Send confidential information, voluminous reports, or energy utility Results of Operations Reports to PUC Filing Center, PO Box 1088, Salem, OR 97308-1088 or by delivery service to 201 High Street SE Suite 100, Salem, OR 97301.

Print

CASCADE NATURAL GAS CORPORATION
A Subsidiary of MDU Resources Group, Inc.

8113 W. GRANDRIDGE BLVD., KENNEWICK, WASHINGTON 99336-7166
TELEPHONE 509-734-4500 FACSIMILE 509-737-7166
www.cngc.com

May 27, 2020

Oregon Public Utility Commission
P.O. Box 1088
Salem, OR 97308-1088

Attn: Filing Center

RE: RG-44(8), Cascade Natural Gas Corporation's 2019 Affiliated Interest Report
And Cost Allocation Manual

Pursuant to OAR 860-027-0100 and OAR 860-027-0048(6), Cascade Natural Gas Corporation ("Cascade" or the "Company") herewith submits its 2019 Affiliated Interest Report and its Cost Allocation Manual.

Please contact me at (509) 734-4593 if you have any questions regarding this filing.

Sincerely,

/s/ Michael Parvinen

Michael Parvinen
Director, Regulatory Affairs

Enclosures

CASCADE NATURAL GAS CORPORATION

Affiliated Interest Report for the
Calendar Year 2019

I. An organizational chart showing the parent company, all subsidiaries, and the percentage of ownership for each.

See the attached organizational chart.

A. Changes in the list of directors and, or other changes in the list of directors and or officers in common to the regulated utility and the affiliated interest.

Please see the attached lists.

B. Changes in successive ownership between the regulated utility and the affiliated interest.

Please see the attached organizational chart for Cascade's affiliates.

C. A narrative description of the affiliated entity with which the regulated utility does business.

- MDU Resources Group Inc. - Parent Company to Cascade Natural Gas Corporation. Provides management/consulting/legal services to Cascade Natural Gas Corporation.
- Knife River Corporation - A subsidiary of MDU Resources. Provides asphalt services for Cascade Natural Gas Corporation. In addition, Cascade leases part of the facility with Knife River and provides distribution system transportation (Tariff Schedule 163) for a Knife River subsidiary company in Central Oregon.
- Centennial Holdings Capital LLC - A subsidiary of MDU Resources. Carries various liability insurance policies on behalf of Cascade Natural Gas Corporation.
- Montana-Dakota Utilities Co. (MDU) – A subsidiary of MDU Resources. Cascade provides 24/7 gas control monitoring of MDU's distribution system and provides notification to the appropriate personnel when a problem is detected.
- Intermountain Gas Co. (IGC) - A subsidiary of MDU Resources. Cascade provides 24/7 gas control monitoring of IGC's distribution system and provides notification to the appropriate personnel when a problem is detected.
- FutureSource Capital Corp. – A subsidiary of Centennial Holdings Capital. Owner of MDUR corporate office buildings and land.

D. A balance sheet and income statement for the twelve months ending December 31, 2019.

Knife River Corporation is part of MDU Resources Construction Materials and Contracting. Below is select Income Statement and Balance Sheet information from the MDU Resources Group Inc. 2019 Annual Report.

Construction Materials and Contracting	
Year ended December 31,	**2019**
Income statement data (Dollars in thousands)	
Operating revenues	$2,189,651
Intersegment revenues	1,066
Total Revenue	$2,190,717
Operating expenses:	
Operation and maintenance and other	1,798,300
Depreciation, depletion and amortization	74,300
Taxes, other than income	44,100
Total Cost of Sales	1,916,700
Gross Margin	274,017
Selling, general and admin expense	
Operation and maintenance	86,362
Depreciation, depletion and amort.	3,100
Taxes, other than income	4,600
Total selling, general and admin	94,062
Operating income	179,955
Earnings (Loss) from Equity Method Investments	-
Other Income (Expense)	1597
Interest expense	23,792
Income (loss) before taxes	157,760
Income taxes	37,389
Earnings (loss) on common stock	$120,371

Construction Materials and Contracting	
Year ended December 31,	**2019**
Balance sheet data (000's)	
Property, plant and equipment	$1,910,562
Total identifiable assets	$1,684,161

MDU Resources Group, Inc.

Year ended December 31,	2019
Balance sheet data (000's)	
ASSETS	
Current assets:	
Cash and cash equivalents	$12,326
Receivables, net	4,727
Accounts rec from subsidiaries	49,943
Inventories	-
Prepayments and other current assets	501
	67,497
Investments	46,294
Investments in subsidiaries	2,842,068
Property, plant and equipment	-
Less accumulated depreciation, depletion And amortization	-
Net property, plant and equipment	-
Deferred charges and other assets	
Goodwill	-
Other	34,520
Total deferred charges and other assets	34,520
Total identifiable assets	**$2,990,379**
LIABILITIES AND STOCKHOLDERS' EQUITY	
Current liabilities:	
Long-term debt due within one year	$ -
Accounts payable	2,981
Accts pay to subsidiaries	4,752
Taxes payable	1,253
Dividends payable	41,580
Accrued compensation	8,812
Other accrued liabilities	7,786
	67,164
Long-term debt	-
Deferred credits and other liabilities:	
Deferred income taxes	-
Other	75,969
Total deferred credits and other liabilities	75,969
Stockholders' equity:	
Preferred stocks	-
Common stock	200,923
Other paid-in capital	1,355,404
Retained earnings	1,336,647

Accumulated other comprehensive loss	(42,102)
Treasury stock at cost – 538,921 shares	(3,626)
Total stockholders' equity:	2,847,246
Total liabilities and stockholders' equity	**$2,990,379**

Year ended December 31,	**2019**
Income statement data (000's)	
Operating revenues	$ 0
Operating expenses	0
Operating income	0
Other income	0
Interest expense	0
Income (loss) before taxes	0
Income taxes	0
Net Income from cont. ops.	$ 0

Intermountain Gas Company

Year ended December 31,	**2019**
Balance sheet data (000's)	
Property, plant and equipment	$759,984
Less accumulated depreciation, depletion and amortization	276,328
	483,656
Deferred charges and other assets:	12,084
Total identifiable assets	**$556,738**

Year ended December 31,	**2019**
Income statement data (000's)	
Operating revenues	$251,547
Operating expenses:	
Purchased natural gas sold	138,805
Operations	53,968
Depreciation and amortization	22,310
Taxes other than income	11,321
Total operating expenses	226,404
Operating income	25,143

Other income (loss)	(428)
Interest expense	5,782
Income (loss) before taxes	18,933
Income taxes	2,888
Net Income	$16,045

Montana-Dakota Utilities Co.

Year ended December 31,	**2019**
Balance sheet data (000's)	
Property, plant and equipment	$2,975,764
Less accumulated depreciation, depletion and amortization	913,102
	2,062,662
Deferred charges and other assets:	244,423
Total identifiable assets	**$2,458,343**

Year ended December 31,	**2019**
Income statement data (000's)	
Operating revenues	$650,996
Operating expenses:	
Fuel and purchased power	86,557
Purchased natural gas sold	182,122
Operations	188,142
Depreciation and amortization	83,287
Taxes other than income	28,625
Total operating expenses	568,733
Operating income	82,263
Other income (loss)	5,196
Interest expense	32,885
Income (loss) before taxes	54,574
Income taxes	(12,548)
Net Income	$67,122

Centennial Holdings Capital LLC

Year ended December 31,	**2019**
Balance sheet data	

Property, plant and equipment	$35,212,646
Less accumulated depreciation, depletion	
And amortization	11,485,857
	23,726,789
Non current investments	
Operating lease-right of usa	158,771
Total identifiable assets	**$23,885,560**

Year ended December 31, Income statement data (000's)	**2019**
Operating revenues	$2,920,500
Operating expenses:	
Operations	3,707,785
Depreciation	502,285
Taxes other than income	1,133
Gain on disp. of property	-
Loss on disp. of property	24,481
Total operating expenses	4,235,684
Operating income	(1,315,184)
Interest income	209,144
Other income	(27,236)
Income (loss) before taxes	(1,133,276)
Income taxes	34,052
Net Income	$(1,167,328)

Future Source Capital Corp.

Year ended December 31,	**2019**
Balance sheet data	
Property, plant and equipment	$34,004,073
Less accumulated depreciation, depletion	
And amortization	11,145,373
	22,858,700
Deferred charges and other assets	32,983
Total identifiable assets	**$30,778,531**

Year ended December 31, Income statement data (000's)	**2019**
Operating revenues	$ 0
Operating expenses:	

Operations	269,592
Depreciation	162,471
Taxes other than income	1133
Gain on disp. of property	-
Loss on disp. of property	22,307
Total operating expenses	455,503
Operating income	(455,503)
Interest income	8,445
Other income	0
Income (loss) before taxes	(446,072)
Income taxes	(110,527)
Net Income	$ (335,545)

II. Service Payments by Cascade to an Affiliate

MDU Resources Group, Inc.			
Account	**Description**	**Total Company**	**Total Oregon**
	MDU/MDUR Consulting-Cap Exp	2,130,630.74	529,035.61
426.1	Donations	211,302.02	52,466.30
426.2	Life Insurance	(569,914.53)	(141,509.79)
426.4	Political Activities	306,253.81	76,042.83
426.5	Other Deductions	1,555.78	0.00
813	Other Gas Supply Expenses	172,369.94	42,799.47
870	Operation Supervision and Engineering	1,236,083.64	306,928.99
874	Mains & Services Expenses	465,128.74	226,068.27
875	Measuring & Regulating Station Expenses General	115,169.47	28,596.59
878	Meter & Housing Regulator Expenses	(0.22)	(0.05)
880	Other Expenses	1,235,529.25	306,745.31
881	Rents	69,876.23	8,605.98
885	Maintenance Supervision and Engineering	80,218.38	19,925.14
887	Maintenance Mains	619,343.70	18,563.42
887.1	Pipeline Integrity	7,141.36	1,773.22
892	Maintenance of Services	199.80	49.61
894	Maintenance of Other Equipment	48,296.66	11,821.05
901	Supervision	44,898.44	11,148.27
902	Meter Reading Expenses	211,446.04	52,502.09

903	Customer Records & Collection Expenses	5,336,032.43	1,324,936.86
904	Uncollectible Accounts	1,209,258.39	215,040.78
908	Customer Assistance Expenses	279,237.45	62,967.35
909	Informational & Instructional Advertising Expenses	166,829.62	51,574.43
920	Administrative & General Salaries	7,255,804.86	1,801,616.17
921	Office Supplies & Expenses	3,391,430.82	842,019.99
922	Administrative Expenses Transferred Credit	(245,017.55)	(60,728.53)
923	Outside Services Employed	267,372.76	67,930.04
925	Injuries & Damages	9,351.41	2,321.97
926	Employee Pensions & Benefits	28,351.40	7,039.61
930.1	General Advertising Expenses	30,962.46	7,687.99
930.2	Misc. General Expenses	753,502.25	187,092.78
931	Rents	1,384,278.64	343,716.39
932	Maintenance of general plant	2,101.15	521.73
	Grand Total	**$ 26,255,025.34**	**6,405,299.87**

Affiliate/Subsidiary	**Description**	**Total Company**	**Total Oregon**
Future Source Capital Corp.	921 Office Supplies & Expenses	$103,102.00	$25,600.23
Knife River Corporation	931 Rent/Various Tariff Distribution	$75,815.20	$75,815.20
Montana-Dakota Utilities Co.	Various Intercompany Services	$13,837,723.50	$3,435,906.75
MDU Resources Group, Inc.	Various Intercompany Services	$6,224,157.86	$1,545,458.40
Intermountain Gas Company	Various Intercompany Services	$1,424,089.87	$353,601.51
Centennial Holdings Capital LLC	928 Injuries & Damages	$1,311,309.76	$325,598.21

SERVICE PAYMENTS BY THE AFFILIATE TO THE UTILITY			
Name	**Description**	**Total Company**	**Total Oregon**
Montana-Dakota Utilities Co.	880 Other Expenses	$ 13,039.55	$ 13,039.55

Descriptions of Basis Pricing
Attached is the Cost Allocation Manual which describes the costing method procedures for Cascade Natural Gas Corporation.

III. Intercompany loans to Cascade from an affiliate or loans from an affiliate to Cascade

A. Month-end amounts outstanding for short term and long term loans.
Cascade made no loans to any of the affiliates during 2019, and no affiliate loaned Cascade money in 2019.

B. The highest amount during the year.
Not applicable.

C. A description of the terms and conditions for loans including interest rate.
Not applicable.

D. The total amount of interest charged and the weighted average rate of interest.
Not applicable.

E. Commission Order approving the transactions.
Not applicable.

IV. Parent guaranteed debt of affiliate
None.

V. Transactions other than services
None.

Attachments

2019 Affiliated Interest Report
Attachments

Table of Contents

Cascade Natural Gas Corporation

Primary Address
8113 West Grandridge Boulevard
Kennewick, Washington 99336-7166

Management Name	Title
Goodin, David L.	Director
Kivisto, Nicole A.	Director
Kuntz, Daniel S.	Director
Vollmer, Jason L.	Director
Chiles, Mark A.	Vice President - Regulatory Affairs and Customer Service
Darras, Patrick C.	Vice President – Engineering and Operations Services
Gilchrist, Hart	Vice President - Safety, Process Improvement and Operations Systems
Goodin, David L.	Chair of the Board
Jones, Anne M.	Vice President - Human Resources
Kivisto, Nicole A.	President and Chief Executive Officer
Kuntz, Daniel S.	General Counsel and Secretary
Liepitz, Karl A.	Assistant Secretary
Link, Margaret (Peggy) A.	Chief Information Officer
Madison, Scott W.	Executive Vice President - Business Development and Gas Supply
Martuscelli, Eric P.	Vice President – Field Operations
Nygard, Tammy J.	Controller
Senger, Garret	Executive Vice President - Regulatory Affairs, Customer Service and Administration
Vollmer, Jason L.	Treasure

Montana-Dakota Utilities Co.

Primary Address
400 North Fourth Street
Bismarck, North Dakota 58501-4092

Management Name	Title
Goodin, David L.	Director
Kivisto, Nicole A.	Director
Kuntz, Daniel S.	Director
Vollmer, Jason L.	Director
Chiles, Mark A.	Vice President - Customer Service
Darras, Patrick C.	Vice President – Engineering and Operations Services
Gilchrist, Hart	Vice President - Safety, Process Improvement and Operations Systems
Goodin, David L.	Chair of the Board
Hourigan, Kirsti B.	Assistant Secretary
Jones, Anne M.	Vice President - Human Resources
Kivisto, Nicole A.	President and Chief Executive Officer
Kuntz, Daniel S.	General Counsel and Secretary
Liepitz, Karl A.	Assistant Secretary
Link, Margaret (Peggy) A.	Chief Information Officer
Madison, Scott W.	Executive Vice President - Business Development and Gas Supply
Martuscelli, Eric P.	Vice President – Field Operations
Nygard, Tammy J.	Controller
Senger, Garret	Executive Vice President - Regulatory Affairs, Customer Service and Administration
Skabo, Jay	Vice President - Electric Supply

Vollmer, Jason L.	Treasurer

MDU Resources Group, Inc.

Primary Address
1200 West Century Ave
Bismarck, North Dakota 58503

Management Name	Title
Everist, Thomas	Director
Fagg, Karen B.	Director
Goodin, David L.	Director
Hellerstein, Mark A.	Director
Johnson, Dennis W.	Director and Chair of the Board
Moss, Patricia L.	Director
Ryan, Edward A.	Director
Sparby, David M.	Director
Wang, Chenxi	Director
Wilson, John K.	Director
Barth, Stephanie A.	Vice President, Chief Accounting Officer and Controller
Goodin, David L.	President and Chief Executive Officer
Hourigan, Kirsti B.	Assistant General Counsel and Assistant Secretary
Jones, Anne M.	Vice President - Human Resources
Kuntz, Daniel S.	Vice President, General Counsel and Secretary
Liepitz, Karl A.	Assistant General Counsel and Assistant Secretary
Link, Margaret (Peggy) A.	Vice President and Chief Information Officer
Riehl, Adrienne L.	Assistant Secretary
Senger, Dustin J.	Assistant Treasurer
Vollmer, Jason L.	Vice President, Chief Financial Officer and Treasurer

Intermountain Gas Company

Primary Address
555 South Cole Road
Boise, Idaho 83709

Management Name	Title
Goodin, David L.	Director
Kivisto, Nicole A.	Director
Kuntz, Daniel S.	Director
Vollmer, Jason L.	Director
Chiles, Mark A.	Vice President - Regulatory Affairs and Customer Service
Darras, Patrick C.	Vice President – Engineering and Operations Services
Gilchrist, Hart	Vice President - Safety, Process Improvement and Operations Systems
Goodin, David L.	Chair of the Board
Jones, Anne M.	Vice President - Human Resources
Kivisto, Nicole A.	President and Chief Executive Officer
Kuntz, Daniel S.	General Counsel and Secretary
Liepitz, Karl A.	Assistant Secretary
Link, Margaret (Peggy) A.	Chief Information Officer

Madison, Scott W.	Executive Vice President - Business Development and Gas Supply
Martuscelli, Eric P.	Vice President – Field Operations
Nygard, Tammy J.	Controller
Senger, Garret	Executive Vice President - Regulatory Affairs, Customer Service and Administration
Vollmer, Jason L.	Treasurer

Centennial Holdings Capital LLC

Management Name	Title
Goodin, David L.	Manager
Kuntz, Daniel S.	Manager
Vollmer, Jason L.	Manager
Goodin, David L.	Chair of the Board, President and Chief Executive Officer
Kuntz, Daniel S.	General Counsel and Secretary
Vollmer, Jason L.	Vice President and Treasurer

FutureSource Capital Corp.

Primary Address:
1200 West Century Avenue, Bismarck, ND 58503

Management Name	Title
Goodin, David L.	Manager
Kuntz, Daniel S.	Manager
Vollmer, Jason L.	Manager
Goodin, David L.	Chair of the Board, President and Chief Executive Officer
Kuntz, Daniel S.	General Counsel and Secretary
Vollmer, Jason L.	Vice President and Treasurer

Knife River Corporation

Primary Address:
P.O. Box 5568,Bismarck, North Dakota 58506-5568

Management Name	Title
Barney, David C.	Director
Goodin, David L.	Director
Kuntz, Daniel S.	Director
Vollmer, Jason L.	Director
Barney, David C.	President and Chief Executive Officer
Christenson, Nancy K.	Vice President - Administration and Treasurer
Ford, Christopher B.	Chief Accounting Officer
Goodin, David L.	Chair of the Board
Kuntz, Daniel S.	General Counsel and Secretary
Liepitz, Karl A.	Assistant Secretary
Pladsen, Glenn R.	Vice President - Operations Support
Ring, Nathan W.	Vice President - Business Development

Cascade Natural Gas

Cost Allocation Manual

2019

CASCADE NATURAL GAS CORPORATION

A Subsidiary of MDU Resources Group, Inc.

In the Community to Serve®

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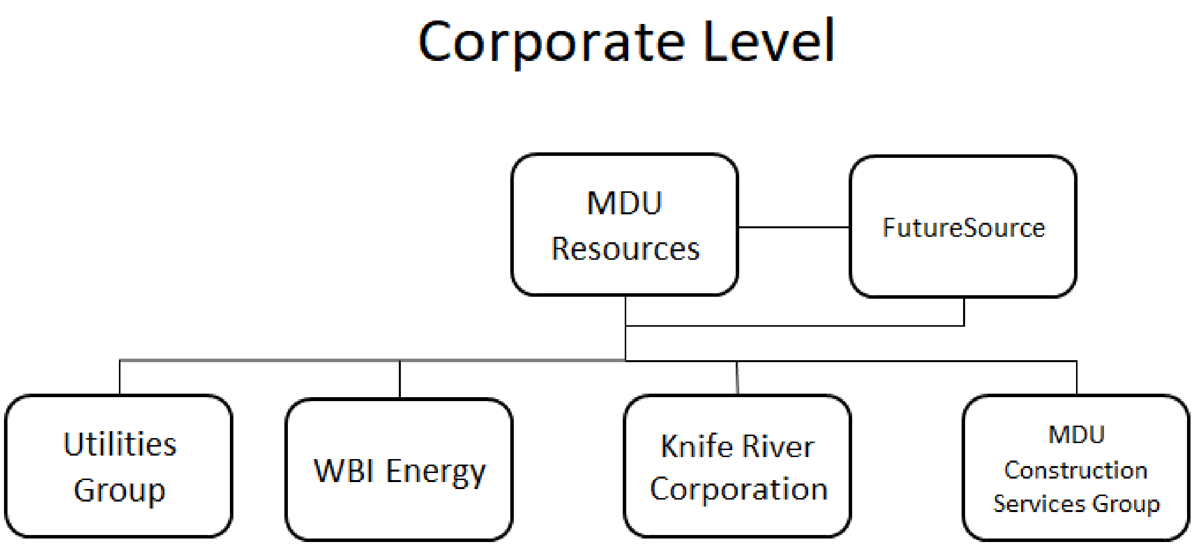
Overview

Cascade Natural Gas Corporation (CNG), a gas distribution company operating in the states of Washington and Oregon, is a subsidiary of MDU Resources Group, Inc. Cascade Natural Gas has its' own set of financial records. The operations of Cascade Natural Gas Corporation are under the direction of one Utility Group (UG) executive leadership team.

FutureSource Capital Corporation (FutureSource) is a separate legal entity that owns the corporate campus facilities that house the MDUR corporate staff and other property utilized in providing services to the operating companies within MDUR.

Below is an overview of the operational structure for the purpose of assigning costs. The diagram presented is intended to provide an overview for cost allocation only and is not intended to represent the legal structure of the Corporation. Note that costs from MDUR and FutureSource are directly assigned or allocated and charged to the operating companies (i.e. Utilities Group, WBI Energy, etc.)



This document is intended to provide an overview of the different types of allocations and the processes employed to direct costs to CNG.

This document will discuss the allocations to/from:

- MDUR and FutureSource to Cascade Natural Gas Corporation
- Montana-Dakota/Great Plains to Cascade Natural Gas Company (CNGC) and Intermountain Gas Corporation (IGC)
- Cascade Natural Gas Corporation (CNG) to Intermountain Gas Company (IGC) and Montana-Dakota/Great Plains
- Utility segment to state jurisdictions

Overall, the approach to allocating costs at each level is to directly assign costs when applicable and to allocate costs based on the function or driver of the cost.

MDU Resources Group, Inc. (MDUR) Allocations

The MDUR corporate staff consists of shared services departments (payroll, human resources, business services and enterprise information technology), and administrative and general departments.

Shared Services

MDU Resources Group, Inc. has several departments that provide specific services to the operating companies. These departments have developed a pricing methodology which is updated annually for the allocation of costs to the MDUR operating companies that utilize their services. (See Exhibit IV) These departments include:

Payroll Shared Services

Payroll Shared Services department provides comprehensive payroll services for MDUR companies and employees. It processes payroll in compliance with appropriate federal, state and local tax laws and regulations. Payroll Shared Services is also responsible for preparation, filing and payment of all payroll related federal, state and local tax returns. It also maintains and facilitates payments and accurate reporting to payroll vendors for employee benefits and other payroll deductions. For Montana-Dakota and Great Plains, the payroll shared services department is also responsible for the accumulation of time entry records and maintenance of employee records. Montana-Dakota and Great Plains do not have any departments that provide these payroll related services.

Human Resources

Human Resources operates as "One HR" across the regulated business units of MDU Resources Group including Montana-Dakota, Great Plains, Cascade Natural Gas, Intermountain Gas, and WBI Energy. There are employees in the HR departments at each of the business units that focus on the operational function of human resources: employee relations, labor relations, staffing, and leave management, all for their specific location. At MDU Resources, shared HR functions are performed for all of the regulated businesses: compensation management, benefits administration, policy development, human resource information systems, organizational development, as well as providing support and backup for the business unit functions.

Business Services

Business Services provides support services for facilities and administrative services (including bill printing), supply chain (purchasing and inventory), fleet, travel, and accounts payable (including unclaimed property). Business Services also creates and maintains the Corporation's national accounts for the purchase of products, goods and services. National accounts take advantage of the combined purchasing power of all the Corporation's operating companies. Business Services is committed to serving its customers by providing timely, standardized, cost-effective goods and services that support business strategies and goals.

Enterprise Information Technology

Enterprise Information Technology (EIT) provides policy guidance, infrastructure related IT functions and security-focused governance. EIT seeks to increase the return on investment in technology through consolidation of common IT systems and services, while eliminating waste and duplication. EIT works to increase the quality and consistency of technology, increase functionality and service to the enterprise, provide governance for managing and controlling risk and reduce costs through economies of scale.

The EIT services get allocated to Montana Dakota using agreed upon formulas based on utilization of the services.

General and Administrative Services

Administrative and general functions performed by MDUR for the benefit of the operating companies include the following departments:

- Corporate governance, accounting & planning
- Communications & public affairs
- Human resources
- Internal audit
- Investor relations
- Legal
- Risk management
- Tax and compliance
- Treasury services

Administrative and general function performed by MDU for the benefit of the utility group include the following departments:

- Corporate governance, accounting & planning
- Customer Service
- Engineering
- Gas Supply
- Human Resources
- Information Technology
- Safety Management

Cascade Natural Gas Corporation receives an allocation of these corporate costs. Corporate Policy No. 50.10 states "*It is the policy of the Company to allocate MDU Resources Group, Inc.'s (MDU) administrative costs and general expenses to the MDU's business units*". Business units described in the policy have been referred to as operating companies in this document. The policy states that costs that directly relate to a business unit will be directly assigned to the applicable business unit and only the remaining unassigned expenses will be allocated to the operating companies using the corporate allocation methodology. The allocation factor developed to apportion MDUR's unassigned administrative costs is a capitalization factor which is based on 12 month average capitalization at March 31, effective July 1 and at September 30, effective January 1 each year. MDUR has a mix of regulated and non-regulated companies. The non-regulated companies are cyclical in nature and could be impacted significantly with a downturn in the economy. It is unlikely during that same downturn their share of corporate costs would be materially different. Due to the volatility of non-regulated companies, and inconsistency between periods of other potential allocation factors, capitalization is the most appropriate allocation factor for MDUR. Capitalization includes total equity and current and non-current long-term debt (including capital lease obligations). The computation of the Corporate Overhead Allocation Factors is shown in Exhibit I.

Cascade Natural Gas is reflected in the Corporate Overhead Allocation Factors in **Exhibit I**. Operating companies that receive allocated costs on a monthly basis from MDUR include:

- Montana Dakota – Electric utility segment
- Montana Dakota/Great Plains – Gas utility segment
- Cascade Natural Gas Corporation (CNGC)
- Intermountain Gas Company (IGC)
- WBI Energy Transmission
- WBI Midstream
- Knife River (KR)
- MDU Construction Services Group, Inc. (CSG)

Corporate costs are recorded in the administrative and general (A&G) function for Cascade Natural Cas Corporation.

FutureSource

FutureSource, a separate legal entity, owns the facilities at the corporate campus that house the MDUR corporate staff and other property utilized in providing services to all the operating companies within MDUR. These include the corporate office, computers, telephones, furniture, fixtures and aircraft. Montana-Dakota/Great Plains acquired an interest in a portion of the land, building, hangar and aircraft with a cash contribution to FutureSource and placed these assets into rate base. Montana-Dakota/Great Plains receives a cost of service return from CNG and IGC for their proportionate share of the contribution made by Montana-Dakota. The revenue received by Montana-Dakota for this cost of service is recorded in miscellaneous revenue.

Annually, FutureSource calculates a cost of service for any unfunded portion of these corporate assets and invoices the operating companies on monthly basis.

Components included in the cost of service for these facilities and other property include operation and maintenance expenses, depreciation, property taxes, income taxes and a pre-tax return on investment. The annual calculation is maintained by FutureSource and the most recent copy may be requested from the MDU Resources Corporate Planning Department.

FutureSource also owns and operates a corporate aircraft and a hangar. Fixed costs for the aircraft are allocated to the MDUR operating companies on the MDUR corporate overhead factor referenced above (Exhibit I). The variable costs are charged to the appropriate business unit as a direct charge on an hourly flight rate. These charges will at times exceed or be below the actual variable cost. A year-end true-up includes an adjustment to the excess or shortfall in such hourly billing. Flights for employees of Montana-Dakota/Great Plains are directly assigned to the appropriate utility segment and state jurisdiction based on the purpose of the trip. For trips that are not directly applicable to a utility segment/jurisdiction, costs are allocated on the employee's standard payroll allocation and subsequently allocated to the jurisdictions. Standard labor distribution allocations are discussed on page 18.

Cascade Natural Gas Corporation Allocation of Cost to/from Others

Allocations to/from other MDUR Companies

Certain Montana-Dakota/Great Plains owned assets, such as the General Office/Annex facility, located at the utility headquarters in Bismarck, and the assets associated with the contribution made for FutureSource assets, are also used for the benefit of other MDUR operating companies. To cover the cost of ownership and operating costs associated with these owned assets, a revenue requirement (asset return plus annual operating expenses) is computed for the shared assets. The expense component included in the return is composed of operating and maintenance costs, depreciation, income tax and property tax expenses. The resulting revenue requirement is billed to the other MDUR operating companies, including CNGC and IGC, as a monthly fee.

Intermountain Gas owns the customer care center located in Meridian, ID. To cover the cost of ownership associated with that owned asset, a revenue requirement (asset return) is computed similarly to Montana-Dakota owned assets. The expense component included in the return is composed of operating and maintenance costs, depreciation and income tax expense. The resulting revenue requirement is billed to the Montana-Dakota/Great Plains and Cascade as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Additionally, a portion of the cost ownership of the Kennewick General Office is billed to Montana-Dakota/Great Plains and Intermountain Gas Company based on office space occupied by shared utility group employees. The expense component included in the return is composed of depreciation, operating expense and income tax.

The resulting revenue requirements are billed to the Montana-Dakota/Great Plains and Intermountain Gas Company as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Additionally, some expenses are allocated or directly assigned at the invoice/PO or credit card purchase stage.

Allocations to other Utility Companies

Montana-Dakota/Great Plains has several departments that provide services to all four utility operating companies (Montana-Dakota, Great Plains, Cascade Natural Gas Co. and Intermountain Gas Company). These departments include:

- Leadership Group - composed of the Executive Group and Directors that oversee shared utility specific functions
- Customer Services - (Call Center, Scheduling and Online Services)
- Operations & Engineering Services Group – composed of shared utility group operations department functions
- Information Technology and Communications- (Enterprise Network & Telecommunications, Enterprise Management, Enterprise Development and Integration, Field Automation, Enterprise GIS)
- Environmental
- Safety & Technical Training
- Business Development
- Gas Supply & Control
- Utility Group Controller

These operational groups have calculated the proper allocation to use to allocate the costs to the utility companies based on services performed for each utility company. The allocation methodology is included in Exhibit V.

Cascade Natural Gas Corporation's Allocations to Utility Segments

Revenues

All sales and transportation revenues are directly assigned to the appropriate state jurisdiction. Miscellaneous service revenue, rent and other revenue is directly assigned to the utility jurisdiction where possible and common derived revenue is allocated to the utility jurisdiction based on the reason for which the revenue was received.

O&M Expense

As operation and maintenance costs are incurred, the expense is directly assigned to the appropriate state jurisdiction in the general ledger where possible. Expenses incurred that are common to both jurisdictions, such as administrative and general costs, are split between jurisdictions based on the function and/or driver of the cost.

Facility Expense Allocations

Costs for operations and maintenance of facilities are charged directly to the applicable utility jurisdiction when the facility is for the benefit of one jurisdiction.

For expenses associated with distribution operation facilities, such as a region office that serves more than one utility jurisdiction, the costs are allocated to the utility jurisdiction based on the current year 3-factor formula.

Labor/Reimbursable expense allocations

The development of standard labor distributions for Cascade Natural Gas employees is described below based on the type of employee. Standard labor distributions are used for all employees to account for certain expenses as detailed below.

Labor, benefit costs and reimbursable expenses are directly assigned to a utility jurisdiction where possible. If the expense is not direct, the appropriate utility segment is charged as follows:

Union Employees

Time tickets are required for productive time. The employee specifies the proper utility segment, location and FERC account based on work performed. To account for non-productive time, standard payroll labor distributions are established for all employees. These standard labor distributions are calculated for union employees based on the historical actual charges by utility segment for the last 12 months.

Non-Union Employees

Non-union employees are not required to submit detailed time tickets with applicable general ledger accounts specified. Rather each employee has a "standard" set of general ledger accounts that split the labor costs to utility jurisdiction based on an expected ratio of work between jurisdictions. This split can be unique and is based on the employee's position. Costs are distributed based on this standard labor distribution for each employee, and the allocations are reviewed annually. Time studies are completed at least every five years.

- Payroll allocations for operations supervisors are a function of their direct reports or may be determined by time studies conducted.
- Payroll allocations for staff engineers are determined by time studies.
- Payroll allocations for General Office support staff are reviewed by the applicable department head based on the type of work performed.

Reimbursable employee expenses are directly assigned to a utility jurisdiction and FERC account when possible. For employee expenses that are applicable to more than one utility jurisdiction, such as training that is not specific to a utility segment, the employee's standard labor distribution percentages for each segment are used.

Taxes Other than Income

Ad valorem taxes are reviewed by function and all functions are directly assigned except for common ad valorem taxes, which follow plant. Payroll related taxes follow the allocation of labor and revenue and electric production taxes are directly assigned. Common taxes other than income, such as the Highway Use tax or Secretary of State filing tax are allocated on the appropriate factor to the segments.

Income Taxes

Income taxes, both current and deferred, are allocated to the utility jurisdiction based on the underlying revenue or expense that generated the deferred taxes.

If the underlying income item is specific to a particular jurisdiction, the related taxes are assigned directly to that jurisdiction. If the underlying income item is common to both jurisdictions, the related taxes are allocated with factors used to allocate the underlying revenue or expense.

Plant in service / work in progress / reserve / depreciation

Plant in service, work in progress, reserve and depreciation expense accounts are assigned to a utility jurisdiction based on the function of property. For property that benefits both utility jurisdictions an allocation process is used.

The allocation process is based on the combination of the location of the asset and the FERC account (function) that is used to allocate the project, asset, reserve and depreciation.

Prepayments

Prepaid demand and commodity charges are directly assigned to the applicable utility jurisdiction. Prepaid insurance is directly assigned where possible and common policies are allocated based on the type of policy.

Customer Advances

Customer advances are directly assigned to the applicable jurisdiction.

Other rate base items

Where possible, these items are directly assigned to the applicable utility jurisdiction. Common items are allocated based on the cost driver for each item.

Cascade Natural Gas Corporation's Allocations to State Jurisdictions

Cascade Natural Gas utilizes an automated allocation process each month to record the income statement and rate base account activity to the financial ledger (state jurisdiction) to facilitate regulatory reporting. This process is based on the general ledger account structure used in the financial software (JD Edwards). As with other items, costs are directly assigned to a jurisdiction when possible. Costs common to more than one state jurisdiction are allocated between jurisdictions. The primary driver of the allocation is the Business Unit component of the general ledger account; however, the FERC account associated with the charge is also used to determine the proper allocation method. Since operation and maintenance costs are assigned to the utility jurisdiction as incurred, this process only allocates costs between state jurisdictions. The allocation process creates a Journal Entry to the JD Edwards jurisdictional ledgers established by state and utility jurisdiction.

The allocation methodology is as follows:

The JD Edwards (JDE) software is used by Cascade Natural Gas for recording financial transactions as well as the jurisdictional allocation process for all accounts except those related to fixed assets.

The account structure within JDE consists of the following components:

<u>Business Unit</u> **-** The Business Unit is one of the primary components used for identifying the regulatory allocation of costs. It usually defines a location such as an operating region, operating district or facility, gas regulator station, or department (i.e. human resources, engineering).

<u>Object</u> **–** The object for operations and maintenance (O&M) expense accounts represents the resource consumed (i.e. payroll or materials). For balance sheet accounts, the object represents the FERC account.

<u>Subsidiary</u> **–** The subsidiary portion of the account for O&M accounts identifies the utility segment and the FERC account. For balance sheet accounts the subsidiary represents a further breakdown of the account such as which bank for a cash account.

<u>Revenue Accounts</u> – Revenues are directly assigned to the jurisdiction when possible. The applicable FERC account is part of the account structure and in

the case of utility billed revenue the utility jurisdiction is included. It is the combination of the business unit, utility segment and FERC that drive the allocation factor used. An example of revenue that is allocated to the jurisdictions is revenue from the cost of service calculation which is assigned an allocable location (Business Unit).

Operation and Maintenance (O&M) accounts – As costs are incurred, the approver of the expense assigns the general ledger account structure.

It is the combination of the location (Business Unit), utility jurisdiction and FERC that drive the allocation factor utilized. Locations are assigned a factor based on the geographic area for which they serve and the FERC function assigned. For example, location (Business Unit) 230 represents the geographic location of the Sheridan, WY District. The Sheridan District serves both electric and gas and is therefore directly assigned to Wyoming for all FERC accounts. Another example is location 12900, representing the Credit and Collections Department. The Credit and Collections Department services both the electric and gas customers. The allocation of costs is based on the FERC range of accounts. The location may also be a responsibility, or department.

Location	Location Description	Sub 1	Sub 2	Utility Segment	Utility Alloc Code	Utility Allocation Description	Utility Allocation Rate	Juris Alloc Code	Juris Allocation Description	Juris Allocation Rate	Combined Effective Rate
230	Wyoming District	1560	15709999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00005	WYOMING ONLY	100.000000%	100.000000%
230	Wyoming District	1580	19359999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00005	WYOMING ONLY	100.000000%	100.000000%
12900	Credit & Collections	1920	19359999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00026	O&M EXCLUDING FUEL & PURCHASED POWER & A&G	8.336614%	8.336614%
12900	Credit & Collections	1901	19169999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00085	TOTAL COMPANY ELECTRIC CUSTOMER COUNT	11.315965%	11.315965%
12900	Credit & Collections	1580	15989999	1 Electric	00001	ELECTRIC ONLY	100.0000%	00118	ELECTRIC DISTRIBUTION PLANT	14.798583%	14.798583%

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00001	230		1560	15709999	199703	203512	Wyoming District	00001	1	00005
00001	230		1580	19359999	199501	203512	Wyoming District	00001	1	00005
00001	230		28120	28120	199703	203512	Wyoming District	00002	2	00005
00001	230		2870	29359999	199501	203512	Wyoming District	00002	2	00005

00001 code = 100 % Electric

00002 code = 100 % Gas

Code 00005 = 100% allocated to WY

*Co	*Location	*Obj Acct	*FERC Sub 1	*FERC Sub 2	*Start Date	Stop Date	Description	Utility Alloc Code	Utility 01	Allocation Code 01
00001	12900		1580	15989999	200910	203512	Credit & Collections	00001	1	00118
00001	12900		1901	19169999	200501	203512	Credit & Collections	00001	1	00085
00001	12900		1920	19359999	200501	203512	Credit & Collections	00001	1	00026
00001	12900		2870	28949999	200910	203512	Credit & Collections	00002	2	00119
00001	12900		2901	29169999	200501	201508	Credit & Collections	00002	2	00086
00001	12900		2901	29169999	201509	203512	Credit & Collections	00002	2	00087
00001	12900		2920	29359999	200501	203512	Credit & Collections	00002	2	00027

Utility Allocation Code
Represents the code used to allocate costs to a business segment
00001 = Electric segment
00002 = Gas segment

Allocation code 01
Represents the code used to allocate costs to a Jurisdiction
00118 = Electric distribution plant
00085 = Total company electric customer count
00026 = O&M excluding fuel & purchased power and A&G
00119 = Gas distribution plant
00087 = Total company gas sales customer count
00027 = O&M excluding cost of gas and A&G

Taxes Other Than Income

Taxes other than income taxes are directly assigned when possible. Ad valorem taxes are allocated based on the subsidiary, which indicates the jurisdiction and function. Payroll related taxes follow the allocation of labor, revenue taxes are directly assigned and generation and other taxes are allocated on the applicable factor.

Income Taxes
Federal taxes that are allocated or directly assigned to the utility jurisdiction are allocated to the jurisdictions based on the factors used to allocate the underlying revenue or expense among the jurisdictions.

State taxes that are allocated or directly assigned to a utility segment, are allocated to the jurisdictions that have state income tax based on their respective state apportionments.

Plant in Service/Work in Progress/Reserve/Depreciation Accounts
Plant in service, work in progress, reserve and depreciation expense accounts are allocated in through a similar process in the PowerPlan software based on attributes associated with the work order and asset.

It is the combination of the utility segment, location of the asset and the FERC account that is used to allocate the project, asset, reserve and depreciation. The tables that are maintained in JDE for jurisdictional allocations are interfaced into PowerPlan and are used to allocate these accounts.

Allocation Factors
The allocation factors are computed annually by the Regulatory Affairs and General Accounting departments and assigned to the proper Business Unit (location) effective in January each year. See Exhibit VI for a list of the allocation factors.

Exhibit I- MDUR Corporate Overhead factor

MDU Resources Group, Inc.
Corporate Overhead Allocation Factor
January - June 2019

	MDU Electric	MDU/GP Gas	CNGC	IGC	WBI Energy Transmission	WBI Energy Midstream	KR	CSG
MDUR Corporate Factor	20.4%	14.0%	14.9%	10.0%	8.3%	0.3%	22.9%	9.2%

MDU RESOURCES GROUP, INC.
12 Month Average Consolidating Balance Sheet
September 2018

	WBI Energy	Knife River	Construction Services	Utilities Group	Consolidated
Debt and Equity					
Short-term borrowings					---
LTD due within one year	1,000,000.00	28,809,524.50	71,239.98	97,035,948.02	126,916,712.50
Long-term debt	184,897,919.53	341,354,594.53	89,118,439.42	1,118,067,733.43	1,733,438,686.91
Total Debt	**185,897,919.53**	**370,164,119.03**	**89,189,679.40**	**1,215,103,681.45**	**1,860,355,399.41**
Stockholders' equity:					
Preferred stocks		---	---	---	---
Common stock	1,000.00	800,000.00	1,000.00	196,082,279.67	196,884,279.67
Other paid-in capital	803,182,762.05	495,748,408.91	134,859,038.50	1,739,022,954.79	3,172,813,164.25
Retained earnings	(586,466,247.50)	123,448,294.30	162,271,164.51	1,081,619,915.31	780,873,126.62
Accumulated other comprehensive income (loss)	(3,158,615.65)	(29,585,480.00)	(2,627,163.98)	(43,006,431.98)	(78,377,691.61)
Treasury stock	---	(3,625,812.59)	---	(3,625,812.59)	(7,251,625.18)
Total common stockholders' equity	**213,558,898.90**	**586,785,410.62**	**294,504,039.03**	**2,970,092,905.20**	**4,064,941,253.75**
Total stockholders' equity	**213,558,898.90**	**586,785,410.62**	**294,504,039.03**	**2,970,092,905.20**	**4,064,941,253.75**
Total liabilities and stockholders' equity	**399,456,818.43**	**956,949,529.65**	**383,693,718.43**	**4,185,196,586.65**	**5,925,296,653.16**
IC Investment in Subsidiaries	---	---	---	1,706,288,626.51	1,706,288,626.51
Fidelity E&P 12 Mth Avg Capitalization	(40,471,854.42)	---	---	---	(40,471,854.42)
Capitalization	**358,984,964.01**	**956,949,529.65**	**383,693,718.43**	**2,478,907,960.14**	**4,178,536,172.23**

	WBI Energy	Knife River	CSG	Utilities Group	Total
MDUR Corporate OH Factor	8.6%	22.9%	9.2%	59.3%	100.0%

	2018 Capitalization (In thousands)	Share of Corp. Allocation	Corporate Allocation	Electric	Gas
Montana-Dakota 1/	$1,465,385	58.0%	34.4%	20.4%	14.0%
Cascade	635,833	25.2%	14.9%		14.9%
Intermountain	425,565	16.8%	10.0%		10.0%
Total Utilities Group	$2,526,783	100.0%	59.3%	20.4%	38.9%

1/ Electric and gas segments allocated on Montana-Dakota's Corporate Overhead Factor

Exhibit II- Montana-Dakota/Great Plains Overhead factor

Montana-Dakota Utilities Co.
Corporate Overhead Allocation Factors
January - June 2019

	Electric	Gas
Montana-Dakota corporate factor	59.2	40.8
Employee factor	42.9	57.1
Plant factor	75.5	24.5
Customer factor	32.6	67.4

Exhibit III- Montana-Dakota/Great Plains Customer Allocation Factors

Montana-Dakota Utilities Co
2019 Customer Allocation Factors

	Customers	% Factor	State % Factor
Montana			
Gas	84,565	0.77	0.20
Electric	25,707	0.23	0.06
	110,272	1.00	0.26
North Dakota			
Gas	109,365	0.54	0.26
Electric	92,817	0.46	0.22
	202,182	1.00	0.49
South Dakota			
Gas	60,402	0.88	0.15
Electric	8,547	0.12	0.02
	68,949	1.00	0.17
Wyoming			
Gas	18,782	0.54	0.05
Electric	15,976	0.46	0.04
	34,758	1.00	0.08
Total Customers	416,161		

Great Plains
Jurisdictional Customer Allocation Factor

North Dakota GPNG	2,275	0.10
Minnesota - GPNG	21,668	0.90
	23,943	1.00

Montana-Dakota Utilities Co
Customer Count Splits for Regions and Districts

Rocky Mountain Region		**Badlands Region**	
MT Gas	65%	ND Elec	36%
WY Elec	16%	ND Gas	23%
WY Gas	19%	MT Elec	22%
		MT Gas	18%
Billings District		SD Elec	1%
All Gas	100%		
Sheridan Dist (#63)		**Reg split (#65)**	
Electric	46%	Electric	59%
Gas	54%	Gas	41%
		Dickinson Dist	
		Electric	58%
Dakota Heartland Region		Gas	42%
ND Elec	34%	***Glendive Dist***	
ND Gas	55%	Electric	56%
SD Elec	5%	Gas	44%
SD Gas	6%	***Williston Dist (#69)***	
		Electric	65%
Region Split (#64)		Gas	35%
Electric	39%	***Wolf Point Dist (#68)***	
Gas	61%	Electric	50%
Bismarck Dist (#86)		Gas	50%
Electric	51%		
Gas	49%		
Mobridge Dist (#14)		**Black Hills Region**	
Electric	58%	SD Gas	100%
Gas	42%		
Jamestown District		***Rapid City District***	
All Gas	100%	All Gas	100%
Minot District		***Spearfish District***	
All Gas	100%	Gas	100%

Customer Allocations by State

GAS		
MT Gas	84,565	31.0%
ND Gas	109,365	40.0%
SD Gas	60,402	22.1%
WY Gas	18,782	6.9%
	273,114	
ELECTRIC		
MT Elec	25,707	18.0%
ND Elec	92,817	64.9%
SD Elec	8,547	6.0%
WY Elec	15,976	11.1%
	143,047	

Exhibit IV- MDUR Shared Services Pricing Methodology

MDU Resources Shared Services
Pricing Methodology - Effective for 2019

Note: Any shared services amount allocated to MDU Resources are charges out to the business units on the corporate allocation factor.

761 – Payroll Shared Services:

Payroll Shared Services costs are invoiced based on the number of employees paid and stated as a cost per check. The word check, for this purpose, generically refers to paper paychecks, direct deposits and pay card transactions.

Checks are charged on a tiered structure, intended to recognize the fixed or baseline effort associated with maintaining a payroll cycle and associated reporting, regardless of number of people paid. It is also intended to reward consolidation of multiple pay groups and companies where possible and to align charges with the additional effort required to maintain multiple pay groups and pay cycles.

The monthly volume for this step pricing is accumulated individually for each pay cycle processed.

Checks for weekly pay cycles, cost per check based on the number of checks written per month:
- $ 4.25 per check for the first 500 checks
- $ 0.25 per check for the next 500 checks
- $ 0.10 per check for each additional check

Checks for non-weekly pay cycles, cost per check based on the number of checks written per month:
- $ 4.25 per check for the first 1500 checks
- $ 0.25 per check for the next 500 checks
- $ 0.10 per check for each additional check

Additionally, there will be a $4.00 charge for each tax payment and $250.00 charge for each quarterly tax filing and $2 charge for each W2

There is a $500 per month minimum charge for each operating company.

There is a premium charge of $50 per transaction for specific off cycle checks and back-pay calculations. Examples of transactions included in the premium charge schedule are missing hours, refunded deductions, length of service awards submitted too late for inclusion in a scheduled payroll process, and back pay calculation because an increase was submitted after the pay period that includes the effective date. Examples of transactions excluded from the premium charge calculation are bonus payments, final paychecks, certified wage settlements, or any payment required as a result of a Shared Service or system error.

766 –Time Entry Shared Services:

Time entry service is provided for the Utility Group and MDU Resources employees based on the average number of employees at each location.

	MDUR	MDU/GP	CNG	IGC	WBIE	KRC	CSG*	Total
Average Number of Employees	205	1,050	365	245				1,865
Total weighted allocation factor	10.99%	56.30%	19.57%	13.14%				100%

* Time Entry Shared Services manually keys time entry for Desert Fire. Payroll Shared Services and Desert Fire agree to use two times the amount of the cost per check rather than a separate time entry charge. The two methods are comparable.

970 – Human Resources:

Human Resources costs for the MDU Resources HR team are based on employees served. The average number of employees at each company for 12 months ending June 30 is calculated, then further broken down to whether they are on the Corporate-held benefit plans and/or retirement plans.

An allocation for each individual HR team member is calculated based on which group(s) of employees they serve. For example, an HR Generalist whose functions serve the Regulated companies would have an allocation to MDUR, MDUG, and WBI. A Benefits Analyst who is responsible for the Health & Welfare plans would have an allocation to the regulated companies as well as KRC and CSG companies who participate in the Corporate plans.

These individual allocations are all combined into one aggregate allocation to be used by all MDUR shared HR employees. The reason for this method is that the same work would need to be absorbed should a vacancy occur. Human Resources has three individuals that are not considered shared services and are allocated on the corporate overhead allocation factor.

	MDUR	MDU/GP	CNG	IGC	WBIE-T	WBIE-M	KRC	CSG	Total
Allocation	4.34%	25.15%	7.60%	5.25%	13.72%	2.61%	22.49%	18.84%	100%

762 –Business Services:
This allocation factor is derived from the results of the following four responsibilities. After allocating the projected (budget) costs for the following four responsibilities to each business unit, based on the weighted allocation factor of each of these four responsibilities, each business unit total is summed and divided by the total cost resulting in the following allocation percentages. Individuals in this responsibility provide oversite and support for the following four responsibilities.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Allocation %	17.66%	32.71%	11.66%	9.55%	0.64%	6.06%	1.48%	12.28%	7.96%	100%

763 –Fleet and Travel:

Fleet and Travel Departments costs are invoiced based on five weighted factors from the previous year:

- Travel – based on corporate factor
- Managed Units
- National Account Spend
- Construction Equipment Acquisitions
- Fleet Acquisitions

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
% of Travel Corporate		34.30%	14.40%	12.50%		8.00%	0.40%	21.70%	8.70%	100%
# Managed Units		36	319	223						578
% of Managed Units		6.23%	55.19%	38.58%						100%
National Account Spend	$1,322,570	$18,679,456	$7,681,820	$4,895,822		$6,196,219	$992,764	$132,526,463	$51,797,911	$224,093,025
% of National Account Spend	0.59%	8.34%	3.43%	2.18%		2.77%	0.44%	59.14%	23.11%	100%
# Construction Equip Acquisitions		69	18	9		7	4	108	107	322
% of Construction Equip Acquisitions		21.43%	5.59%	2.80%		2.17%	1.24%	33.54%	33.23%	100%
# Fleet Acquisitions		29	25	29		40	7	166	127	423
% of Fleet Acquisitions		6.86%	5.91%	6.86%		9.46%	1.65%	39.24%	30.02%	100%
Weighted Allocation Factors:										
Travel Corporate	21.70%	The percent of time spent on corporate travel.								
# Managed Units	15.66%	The percent of time spent on managed units.								
National Acct Spend	15.66%	The percent of time spent on national accounts.								
Construction Equip Acquisition	23.49%	The percent of time spent on the acquisition of construction equipment assets.								
Fleet Acquisition	23.49%	The percent of time spent on the acquisition of vehicle assets.								
	MDUR	**MDU/GP**	**CNG**	**IGC**	**WBIE**	**WBIT**	**WBIM**	**KRC**	**CSG**	**Total**
Total weighted allocation factor	0.09%	16.37%	15.00%	11.36%		4.90%	0.84%	31.07%	20.37%	100%

764 –Supply Chain:

There are several individuals that are primarily focused on the Utility Group and some that have multiple business unit responsibilities.

Allocations are based on two weighted factors from previous year:

- Purchase Order Count
- Purchase Order Line Count

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Purchase Order Count	29	4413	908	971		835	252			7,408
% of Purchase Orders	0.39%	59.57%	12.26%	13.11%		11.27%	3.40%			100%
Purchase Order Line Count	44	26,707	2,770	2,858		4,876	1,479			38,734
% of Purchase Order Line Count	0.11%	68.95%	7.15%	7.38%		12.59%	3.82%			100%
Weighted Allocation Factors:										
PO Count	1.00%	The percent of purchase orders processed by Company.								
PO Line Count	99.00%	The percent of lines on purchase orders processed by Company.								
	MDUR	**MDU/GP**	**CNG**	**IGC**	**WBIE**	**WBIT**	**WBIM**	**KRC**	**CSG**	**Total**
Total weighted allocation factor	0.12%	68.86%	7.20%	7.44%		12.57%	3.81%			100%

767 –Accounts Payable:
Costs are invoiced based on four weighted factors from previous year:
- Number of Payments
- Number of Vouchers
- Number of Unclaimed Property reports
- Number of PNC payments

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
# of Payments - 8/1/2017 through 8/1/2018	2,133	32,726	20,778	18,433		6,686	2,044		739	83,539
% of Payments	2.55%	39.17%	24.87%	22.07%		8.00%	2.45%		0.89%	100%
# of Vouchers - 8/1/2017 through 8/1/2018	2,497	49,487	32,806	23,596		11,911	3,312		1,525	125,134
% of Vouchers	1.99%	39.55%	26.22%	18.85%		9.52%	2.65%		1.22%	100%
# of States Filed In - as of 5/26/2018		34	17	28		23	3	10	4	119
% of Unclaimed Property		28.57%	14.29%	23.53%		19.33%	2.52%	8.40%	3.36%	100%
# of Companies Implemented - as of 8/1/2018	3	1	1	1		1	1	19	16	43
% of PNC	6.98%	2.32%	2.33%	2.33%		2.32%	2.32%	44.19%	37.21%	100%
Weighted Allocation Factors:										
# of Payments	15.00%	The percent of time spent on processing payments, setting up address book records, 1099s, etc.								
# of Vouchers	65.00%	The percent of time spent on vouchering and reviewing invoices								
# of Unclaimed Property	15.00%	The percent of time spent filing unclaimed property reports, sending due diligence letters, defending audits.								
# of PNC	5.00%	The percent of time spent with companies that are using PNC to make vendor payments.								
	MDUR	**MDU/GP**	**CNG**	**IGC**	**WBIE**	**WBIT**	**WBIM**	**KRC**	**CSG**	**Total**
Total weighted allocation factor	2.00%	36.00%	23.00%	19.20%		10.40%	2.60%	3.50%	3.30%	100%

770 –Buildings and Grounds:
This allocation is based on labor hours spent by location from the previous year

	MDUR	MDU/GP	CNG	IGC	WBIE	KRC	CSG	Total
Allocation %	43.00%	50.00%			4.00%	3.00%		100%

Enterprise Information Technology (EIT):

There are several EIT departments, and each is billed out based on its own criteria. They are as follows:

Application Services (765) – The allocations will be based on time tracked history for the 12 months of the prior year. The MDUG portion is further divided by meter count and the WBI portion is further divided by the WBI corporate factor.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load	3,977	2,955	1,944	2,347		970	103	1,234	237	13,767
% of 12 mon work load	28.89%	21.46%	14.12%	17.05%		7.05%	0.75%	8.96%	1.72%	100%

Definition of 765: This team is made up of software developers providing integrations to systems and software changes.

Operational Technology (768) –The allocations are based on projected work load. This department is 100% direct allocated based on the projects assigned.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Projected Hours	661	5.579								6,240
% of 12 mon work load	10.60%	89.40%								100%

Definition of 768: This team is made up of security and infrastructure technicians.

Customer Relations (965) – Enterprise charges for the customer relations group are invoiced using three weighted allocation factors. The factors are as follows:

1. Direct charge for employees working for a specific business
2. Number of computing devices supported by the help desk (90%)
3. Number of mobile devices supported by the help desk (10%)

The metric used to determine device counts is devices that have checked into active directory during a 60-day period in the summer of 2018 and active devices in MobileIron.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges			53.53%	46.47%						100%
Factor- 13.49%			7.22%	6.27%						13.49%
Computing Device Counts	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of Device Count	4.58%	18.53%	7.45%	9.56%	0.79%	4.52%	0.67%	27.59%	26.31%	100%
% of Device Factor- 77.86% (86.51% x 90%)	3.57%	14.42%	5.80%	7.44%	0.62%	3.52%	0.53%	21.48%	20.48%	77.86%
Mobile Device Counts	159	561	277	195	207			1,866	2,410	5,675
% of Device Count	2.80%	9.89%	4.88%	3.43%	3.65%			32.88%	42.47%	100%
% of Device Factor- 8.65% (86.51% x 10%)	0.24%	0.86%	0.42%	0.30%	0.32%			2.84%	3.67%	8.65%
Total weighted allocation factor	3.81%	15.28%	13.44%	14.01%	0.94%	3.52%	0.53%	24.32%	24.15%	100%

Definition of 965: This team is made up of help desk agents who support company owned devices and software.

Communications (971)

Enterprise charges for the communications group are invoiced using four weighted allocation factors. The factors are as follows:

1. Direct charge for employee hours working for a specific business (10.53%) (MDUG portion is split by meter count).
2. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (35.79%)
3. Internet/Firewall Access – Number of computing devices (35.79%)
4. IP Telephony (17.89%)

The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges		40.78%	26.83%	32.39%						100%
Factor- 10.53%		4.29%	2.83%	3.41%						10.53%
WAN/LAN/MAN	7	61	19	13	1	144	3	222	78	548
% of Business Unit Locations	1.28%	11.13%	3.47%	2.37%	0.18%	26.28%	0.55%	40.51%	14.23%	100%
Factor- 35.79%	0.46%	3.98%	1.24%	0.85%	0.06%	9.41%	0.20%	14.50%	5.09%	35.79%
Internet Access/Firewall	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of User Accounts	4.58%	18.53%	7.45%	9.56%	0.79%	4.52%	0.67%	27.59%	26.31%	100%
Factor- 35.79%	1.64%	6.63%	2.67%	3.42%	0.28%	1.62%	0.24%	9.87%	9.42%	35.79%
IP Telephone	256	822	435	389		269	35	1,747	177	4,130
% of Handsets	6.20%	19.90%	10.53%	9.42%		6.51%	0.85%	42.30%	4.29%	100%
Factor- 17.89%	1.11%	3.56%	1.88%	1.69%		1.16%	0.15%	7.57%	0.77%	17.90%
Total weighted allocation factor	3.21%	18.46%	8.62%	9.37%	0.34%	12.19%	0.59%	31.94%	15.28%	100%

Definition of 971: This team supports the wide area network and phones. This includes switches, routers and firewalls.

Operations (972) – Enterprise charges for the operations group are invoiced using three separate factors

(1) 18.12% are direct charges that are costs directly related to the AS/400 computer and are invoiced upon the AS/400 allocation as agreed to by MDU and WBI.

The remaining 81.88% of the costs are based upon the number of servers that are supported for each business unit. These servers are then broken out between full service servers and shared service servers. Full service servers have a greater weighting factor since they require more dedicated time and cost more.
(2) Full Service Servers - 61.41% (81.88% x 75%)
(3) Shared Service Servers 20.47% (81.88% x 25%).

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Direct Charges	4.93%	39.76%	22.80%	23.85%	8.34%				0.32%	100%
Factor- 18.12%	0.90%	7.20%	4.13%	4.32%	1.51%				0.06%	18.12%
Full Service Servers	240	84	1	2	32	5		133	36	533
% of Full Service Servers	45.03%	15.76%	0.19%	0.38%	6.00%	0.94%		24.95%	6.75%	100%
Factor- 61.41%	27.65%	9.68%	0.12%	0.23%	3.69%	0.58%		15.32%	4.14%	61.41%
Shared Service Servers		131	38	92		31	3	49	105	449
% of Full Service Servers		29.18%	8.46%	20.49%		6.90%	0.67%	10.91%	23.39%	100%
Factor- 20.47%		5.97%	1.73%	4.19%		1.41%	0.14%	2.24%	4.79%	20.47%
Total weight allocation factor	28.55%	22.85%	5.98%	8.74%	5.20%	1.99%	0.14%	17.56%	8.99%	100%

Definition of 972: This team is responsible for administration of the enterprise servers.

Security (977) – Enterprise charges for the security group are distributed via the number of computing devices (90.00%) and mobile devices (10.00%). Costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
Computing Device Counts	313	1,266	509	653	54	309	46	1,885	1,798	6,833
% of Device Factor- 90%	4.12%	16.67%	6.70%	8.60%	0.72%	4.07%	0.61%	24.83%	23.68%	90.0%
Mobile Device Counts	159	561	277	195	207			1,866	2,410	5,675
% of Device Factor- 10%	0.28%	0.99%	0.49%	0.34%	0.36%			3.29%	4.25%	10.0%
Total weighted allocation factor	4.40%	17.66%	7.19%	8.94%	1.08%	4.07%	0.61%	28.12%	27.93%	100%

Definition of 977: This team supports the cyber security initiatives.

ERP (956) – Enterprise charges for the ERP group are being allocated based on 12 months of the prior year hours worked in JIRA. The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load	927	885	362	196	1,064			277		3,711
% of 12 mon work load	24.98%	23.84%	9.76%	5.29%	28.67%			7.46%		100%

Definition of 956: This team supports the accounting software.

Scada (968) – Enterprise charges for the SCADA group are being allocated based on 12 months of the prior year of hours worked in JIRA. The costs are invoiced based on the following percentages:

	MDUR	MDU/GP	CNG	IMG	WBIE	WBIT	WBIM	KRC	CSG	Total
12-month work load		444	438	528		2,707				4117
% of 12 mon work load		10.78%	10.64%	12.83%		65.75%				100%

Definition of 968: This team supports the gas SCADA systems.

Governance (982) –. Costs for the governance and administration group are invoiced based on a weighting of the combined methodologies of the eight previous EIT responsibilities.

	MDUR	MDU/GP	CNG	IGC	WBIE	WBIT	WBIM	KRC	CSG	Total
2019 % of Total Governance & Administration	15.73%	22.88%	9.23%	10.66%	3.24%	7.76%	0.44%	18.66%	11.40%	100%

Exhibit V- Utility Operations Support Allocation Methodology

Leadership Group:

President & CEO (985) – The payroll allocations will be based on average Utility Group customer and employee counts for the President & CEO and Executive Assistant.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	118,169	245,530	293,376	365,744	1,022,819
% of Factor – 50%	5.75%	12.03%	14.34%	17.88%	50%
Utility Group Employee Counts	431	573	338	242	1,584
% of Factor – 50%	13.60%	18.10%	10.65%	7.65%	50%
Total weighted allocation factor	19.4%	30.1%	25.0%	25.5%	100%

Executive Vice President of Business Development & Gas Supply (701) – The payroll allocations will be based on Utility Group customer counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.0%	28.7%	35.8%	100%

Vice President of Safety, Process Improvement & Operations Systems (707) – The payroll allocations will be based on Utility Group meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Executive Vice President of Regulatory Affairs, Customer Service & Administration (919) – The payroll allocations will be based on meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Vice President of Operations & Engineering Service (960) – The payroll allocations will be based on Utility Group customer counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.0%	28.7%	35.8%	100%

Customer Service Group:

The Customer Service group is made up of four distinct areas and provides service to all four brands within the MDU Utility Group. Those areas are Credit and Collections, Scheduling, Customer Service, and Customer Programs and Support. In addition to these departments, the Customer Service group has a management team, Consumer Specialists, and other administrative positions. Customer Service payroll costs are allocated using five (5) different methodologies: Customer Count, Customer Call Time, Cleared Order Count, Credit To-Dos, and Emails and Web Requests. Costs other than payroll will be allocated based on customer count if they provide benefit for all brands. Costs specific to a brand will be charged directly to that brand and will not go through an allocation process.

Customer Count

- Based on the average customer count of each utility brand from December to November.
- Uses a customer weighting of 1 for each natural gas or electric only customer and 1.25 for each electric/natural gas combination customer.
- The following positions will be allocated based on customer count ***with nonutility***:
    - Customer Service Director
    - Manager, Customer Service
    - Supervisor, Customer Service
    - Customer Service Trainer
    - Customer Service Team Lead (Support)
- The following positions will be allocated based on customer count ***without nonutility***:
    - Administrative Assistant
    - Customer Service Team Lead (Credit)
    - Customer Project Analyst I and II
    - Supervisor, Scheduling & Customer Support
    - Manager, Customer Service & Credit
    - Customer Communications Coordinator
    - Supervisor, Credit & Collections
    - Manager, Scheduling, Support, Prgm
    - Scheduling Analyst
    - Scheduling Lead

Customer Call Time

- Based on the total time that Customer Service Agents are handling a call.
    - Includes total talk time and after call work
    - Does not include idle time or auxiliary time
- Uses data for the preceding December to November of each year.
- The following positions will be allocated based on customer call time:
    - Customer Service Rep I, II, III, IV, and IV PT

- ***Cleared Order Count***
    - Based on the number or work orders cleared through the work assignment management system for each brand.
    - Uses data for the preceding December to November of each year.
    - The following positions will be allocated based on cleared order count:
        - Scheduler

- ***Credit To-Do's***
    - Based on three types of completed To-Do's;
        - accounts up for severance

    - closed accounts pending write-off
    - broken payment plans
  - Uses data for the preceding December to November of each year.
  - The following positions will be allocated based on credit to-do's:
    - Credit & Collections Rep I, II, and III
    - Credit Support Rep

- ***E-mails and web requests***
  - Based on e-mails that include direct inquiries from customers, follow up requests from a CSR phone call, or e-mails generated by the web applications requiring account maintenance.
  - Uses data for the preceding December to November of each year.
  - The following positions will be allocated based on e-mails
    - Customer Support Rep I, II, and III

	MDU Elect	MDU/GP Gas	MDU Nonutility	CNG	IGC	Total
Customer Counts	11.82%	24.51%	.74%	28.1%	34.83%	100%
Customer Counts	12.06%	25.01%	-	28.1%	34.83%	100%
Customer Call Time	12.49%	25.9%	-	27.9%	33.71%	100%
Cleared Order Count	10.48%	21.91%	-	35.88%	31.73%	100%
Credit To-Dos	15.53%	32.21%	-	19.63%	32.63%	100%
Emails	10.05%	20.85%	-	30.92%	38.18%	100%

Operations & Engineering Services Group:

Process Improvement & Operations Tech (Dept 703)
The payroll allocations will be based on the Utility Group employee counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Employee Counts	27.2%	36.2%	21.3%	15.3%	100%

Quality Control (Dept 730)
The Quality Control department provides oversight and post work review of both maintenance and construction work that is performed by both utility group employees and our contractors. The payroll allocations will be based on time studies.

Engineering Services (Dept 769)
The Engineering Services department duties include gas modeling, working with district personnel, engineering design of capital projects, creation of cost estimates, creation of design and work plans, budget planning, etc. The payroll allocations will be based on time studies.

Construction Services (Dept 863)
The Construction Services (CS) department provides construction management and inspection for large and high-pressure projects, as well as for projects generated by TIMP, DIMP, and MAOP Validation Plans. CS creates and manages programs and procedures for welding and fusion programs. Fabrication standards and a majority of fabrication are done by CS. The payroll allocations will be based on time studies.

Operation Systems (Dept 864)
This department supports Operations compliance systems as well as supporting other systems that Operations and Engineering utilize. The group not only supports these efforts but also works as a liaison group between the business and enterprise information technology (EIT). The payroll allocations will be based on time studies. Costs specific to a brand will be charged directly to that brand and will not go through an allocation process.

System Integrity (Dept 865)
The System Integrity department is responsible for the Utilities Distribution and Transmission Integrity Management Programs, Integrity Projects, Cascade's MAOP Validation Project, and Corrosion Control. The payroll allocations will be based on time studies.

Safety Management System & Quality Assurance (Dept 866)
The Safety Management System and Quality Assurance (SMS/QA) department is responsible for the implementation of the utility group's safety management system. The team is responsible for reviewing, documenting, and developing processes to ensure compliance with the industry recommend practice 1173. Key objectives of our current plan include the development of an operational risk management program, SMS/QA program oversight and metrics, and completion of risk-based process audits. The payroll allocations will be based on Utility Group gas customer count.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Gas Customer Counts	-	31.2%	30.6%	38.2%	100%

Operations Policies & Procedures (Dept 923)
This department is responsible for aligning new Utility Group procedures as well as maintaining all previous company specific procedures. Each company was and is required to have and maintain these procedures per federal code 192. The payroll allocations will be based on an equal share across the gas segments.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Allocation %	-	34.0%	33.0%	33.0%	100%

Operation Services (Dept 958)
The Operation Services department provides compliance, damage prevention, and public awareness across the Utility Group. The payroll allocations will be based on time studies.

<u>Information Technology and Communications Group:</u>

Enterprise Network & Telecommunications (Dept 721)
This department processes bill payment files, provides scheduled and Ad Hoc reporting, and monitors nightly batch file updates. The payroll allocations will be based on Utility Group Capitalization Factor.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Capitalization Factor	34.3%	23.7%	25.2%	16.8%	100%

Enterprise Management, Enterprise Development and Integration, Field Automation (Dept 723, 926, 964)
These teams support business and technical functions that are common to all brands. Provides support to the business through data requests and augments the system by developing programs and technical solutions to accommodate business and field needs as well as regulatory requirements. The payroll allocations will be based on Utility Group meter counts.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Enterprise GIS (Dept 951)
This department provides gas, electric and fiber pipeline and facilities mapping services for the Utility Group The payroll allocations will be based on Utility Group meter counts or time studies.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%

Environmental (Dept 889)
The Environmental Department provides environmental regulatory compliance guidance and assistance to MDU Utilities Group facilities and operations in accordance with the company environmental policy: The Company will operate efficiently to meet the needs of the present without compromising the ability of future generations to meet their own needs. Our environmental goals are:

- To minimize waste and maximize resources.
- To support environmental laws and regulations that are based on sound science and cost-effective technology; and
- To comply with or exceed all applicable environmental laws, regulations and permit requirements.

The payroll allocations will be based on time studies.

Safety & Technical Training (Dept 720, 901)
The Safety and Technical Training department provides oversight for all things safety and technical training for the entire utility group. The payroll allocations will be based on Utility Group or Montana-Dakota employee counts or time studies, depending on the employee's job functions.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Employee Counts	27.2%	36.2%	21.3%	15.3%	100%
Montana-Dakota Utilities Employee Counts	42.9%	57.1%	-	-	100%

Business Development (Dept 918)
The payroll allocations will be based on time studies.

Gas Supply (Dept 931, 933)
The payroll allocations will be based on two methodologies: Utility Group meter count and time studies. There are employees focused on Montana-Dakota Utilities functions, which will be allocated 100% to Montana-Dakota Utilities gas segment.

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Meter Counts	-	40.5%	26.5%	33.0%	100%

Utility Group Controller (Dept 941)
The Controller Department provides various accounting services to the Utility Group: Fixed Assets Accounting, Revenue Accounting, Internal Controls Coordination, and Management. The payroll allocations are based on these methodologies: Utility Group customer count, Utility Group meter count, number of employees, Montana-Dakota customer factor, Utility Group corporate factor, Montana-Dakota corporate factor, and specific shared services methodologies.

- ***Utility Group customer count***
  - The following positions will be allocated based on Utility Group customer count based on job duties/functions:
    - Business Analyst I and II (Revenue Accounting)
- ***Utility Group meter count***
  - The following positions will be allocated based on Utility Group meter count based on job duties/functions:
    - Business Analyst II and Sr. (Customer Accounting)
- ***Number of employees***
  - The following positions will be allocated based on number of employees under their supervision:
    - Controller – Utility Group
    - Director, Finance
    - Manager, Revenue Administration
- ***Montana-Dakota customer factor***
  - The following positions will be allocated based on MDU customer factor
    - Financial Analyst I, II (Revenue Accounting)
    - Financial Specialist (Revenue Accounting)
    - Financial Technician (Revenue Accounting)
    - Manager, Revenue Accounting

- ***Utility Group corporate factor***
  - The following position will be allocated based on Utility Group corporate factor
    - Internal Controls Coordinator
- ***Montana-Dakota corporate factor***
  - The following positions will be allocated based on MDU corporate factor
    - Financial Analyst I, II, III, IV (Gen Acctg, Reporting & Planning)
    - Financial Systems Analyst (Gen Acctg)
    - Financial Technician (Gen Acctg)
    - Manager, Accounting & Finance
    - Manager, Financial Reporting & Planning
    Manager, General Accounting

	MDU Elect	MDU/GP Gas	CNG	IGC	Total
Utility Group Customer Counts	11.5%	24.1%	28.7%	35.7%	100%
Utility Group Meter Counts	13.4%	27.1%	26.5%	33.0%	100%
Number of Employees: Controller*	34.75%	24.0%	22.5%	18.75%	100%
Number of Employees: Director, Finance*	32.4%	22.4%	25.8%	19.4%	100%
Number of Employees: Manager, Revenue Administration**	19.1%	39.4%	22.0%	19.5%	100%
Montana-Dakota Customer Factor	32.6%	67.4%	-	-	100%
Utility Group Corporate Factor	34.4%	23.6%	25.1%	16.9%	100%
Montana-Dakota Corporate Factor	59.2%	40.8%	-	-	100%

* MDU electric/gas split is based on the MDU Corporate Factor.
** MDU electric/gas split is based on the MDU Customer Factor.

- ***Utility Group Fixed Assets Accounting methodology***
  - The following positions will be allocated based on time study:
    - Financial Analyst I, II, III, IV (Fixed Assets Accounting)
    - Supervisor, Fixed Assets Accounting
    - Manager, Fixed Assets Accounting

Costs for the Financial Analysts in the MDU Utility Group Fixed Asset Accounting group are invoiced based upon three separate methodologies based on the three major types of work performed in the department. The three major work types of work are:

1. Capital Expenditure Support (21.5% of workload)-Allocated to capital overhead (ES/GA) accounts based on 3-year average of capital expenditures.
2. Fixed Asset Life Cycle Support (63.5% of workload)-Allocated to capital overhead (ES/GA) accounts based on 3-year average of capital work orders weighted by a difficulty factor.
3. All Other Fixed Asset Accounting (15.0% of workload)-Allocated to expense (O&M) accounts based on estimate of time spent on non-project related tasks (Depreciation, ARO, Data Requests, etc.).

	MDUR*	MDU	WBIE**	KRC**	CSG**	CNG	IGC	Total
3-Year Average Capital Expenditures (Millions)		249.4				50.6	38.6	338.6
% of 3-Year Average Capital Expenditures		73.66%				14.94%	11.40%	100.00%
Capital Expenditure Support-21.5% Weight		15.84%				3.21%	2.45%	21.50%
3-Year Average Capital Work Orders		1,930				1,949	862	4,741
Difficulty Factor		68.29%				25.00%	25.00%	
Weighted % of 3-Year Average Capital WO's		65.22%				24.11%	10.67%	100.00%
Fixed Asset Life Cycle Support-63.5% Weight		41.41%				15.31%	6.78%	63.50%
% of Non-Project Related Task Time		62.64%				18.68%	18.68%	100.00%
All Other Fixed Asset Accounting-15% Weight		9.40%				2.80%	2.80%	15.00%
Totals		**66.65%**				**21.32%**	**12.03%**	**100.00%**
Total Allocated to ES/GA		57.25%				18.52%	9.23%	85.00%
Total Allocated to O&M		9.40%				2.80%	2.80%	15.00%

* Time devoted to CHCC companies deemed immaterial and is included in MDU amounts.
** No service provided to WBIE, CSG or CSG

Costs for the Manager of the Utility Group Fixed Asset Accounting group are invoiced based upon the company workload split of the "Other Fixed Asset Accounting" time spent by the Lead Financial Analyst in charge of depreciation, ARO's, data requests, etc. No portion of these costs is allocated to capital overhead (ES/GA) as they are deemed to be non-direct construction support costs.

	MDUR*	MDU	WBIE**	KRC**	CSG**	CNG	IGC	Total
Other Fixed Asset Acct. Workload of Lead Non-Project Support F/A		50.00%				10.00%	10.00%	70.00%
% Allocation of UGFA Manager Costs to O&M		71.42%				14.29%	14.29%	100.00%
Totals		**71.42%**				**14.29%**	**14.29%**	**100.00%**

* Time devoted to CHCC companies deemed immaterial and is included in MDU amounts.
** No service provided to WBIE, CSG or CSG

- ***Utility Group Payment Processing methodology***
    - Payment Processer (Revenue Accounting)
    - Payment Processer, Lead (Revenue Accounting)

Payment Processing has been allocated by utility brand based on the number of customer payments posted to utility accounts in the 12 month period ending June 30, 2018.

	CNG	IGC	MDU/GPNG	Total
# of Payments Processed	957,174	1,057,909	1,876,189	3,891,272
% of Payments Processed by Brand	24.6%	27.2%	48.2%	100%

Exhibit VI- Utility Operations Allocation Factors

Cascade Natural Gas Corporation
State Allocation Formulas
2018

	Washington	Oregon	Total
Customers	74.30%	25.70%	100.00%
Employees	73.72%	26.28%	100.00%
Gross Plant	77.49%	22.51%	100.00%
3-Factor Formula	75.17%	24.83%	100.00%
Rate Base Ratio	75.54%	24.46%	100.00%

	Cascade Natural Gas Corporation Average No. of Employees 2018			
Source: Customers Per Employee report		Washington District Employees (1)	Oregon District Employees (1)	
	Mo-Yr			
	Dec-17	172	62	
	Jan-18	173	62	
	Feb-18	173	60	
	Mar-18	173	60	
	Apr-18	172	60	
	May-18	172	59	
	Jun-18	179	62	
	Jul-18	179	63	
	Aug-18	177	63	
	Sep-18	169	63	
	Oct-18	170	63	
	Nov-18	176	65	
	Dec-18	174	65	
		2,259	807	
Average of Monthly Averages		174	62	236
	Percentage	73.72%	26.28%	100.00%

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2018

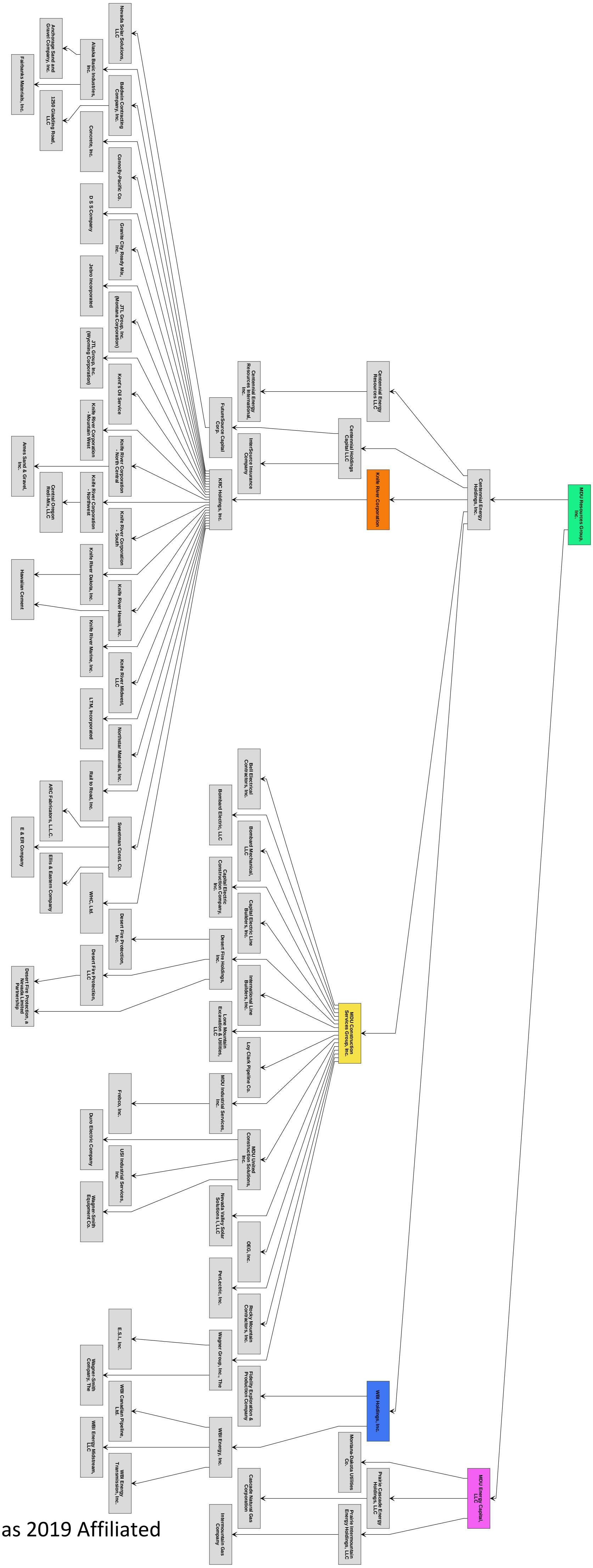
	Washington Incl. CCNC	Oregon Incl. CCNC	Total
Avg. of Mo. Avg.s	780,275,999	226,716,210	1,006,992,209
Percentage	77.49%	22.51%	100.00%

Cascade Natural Gas Corporation Average Number of Customers 2018		
	Average No. of Customers	Percentage
Washington	214,996	74.30%
Oregon	74,377	25.70%
Total	289,373	100.00%

Cascade Natural Gas Corporation
Rate Base Ratio
2018

The following percentages are used for allocating interest on debt:

	2018 Average Rate Base	Plant Formula
Washington	302,980,258	75.54%
Oregon	98,079,245	24.46%
	401,059,503	100.00%



As of March 2, 2020

CASE: UG 390
WITNESS: SABRINNA SOLDAVINI

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1004

Exhibits in Support
Of Opening Testimony

July 30, 2020

Guidelines for Cost Allocations and Affiliate Transactions:

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

CASE: UG 390
WITNESS: DR. MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1100

Opening Testimony

July 30. 2020

Q. Please state your name, occupation, and business address.

A. My name is Max St. Brown. I have been employed by the Public Utility Commission of Oregon (OPUC) since April of 2020, when I returned to the OPUC from an analyst position at the Department of Revenue. I had previously worked at the OPUC for several years. I am a Senior Analyst within the Energy Resources and Planning Division. My business address is 201 High St., Salem, Oregon 97301-3612.

Q. Please describe your educational background and work experience.

A. My Witness Qualification Statement is found in Exhibit Staff/1101.

Q. What is the purpose of your testimony?

A. I am providing a statement that Cascade, AWEC, CUB and Staff (Settling Parties) have reached a settlement in principle on LRIC, rate spread, and rate design issues, and therefore, no substantive testimony on these issues will be offered. The settlement in principle relates to the opening testimony and supplemental opening testimony of Company witness Pamela J. Archer in Exhibits CNGC/500 CNGC/600. The Settling Parties will soon be filing a Stipulation on those issues along with supporting testimony.

Q. Does this conclude your testimony?

A. Yes.

CASE: UG 390
WITNESS: DR. MAX ST. BROWN

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 1101

Witness Qualifications Statement

July 30, 2020

WITNESS QUALIFICATIONS STATEMENT

NAME:	Max St. Brown
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Utility Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	Ph.D., Economics (2013) Washington State University B.S., Economics (2009) Central Washington University
EXPERIENCE:	I have been employed by the Public Utility Commission from July 2015 to December 2018 and since April 2020, with my current position being a Senior Utility Analyst, in the Utility Program's Energy Resources and Planning Division. Prior to rejoining the OPUC, I worked as a Senior Economist in the Research Section at the Oregon Department of Revenue. From 2013 to 2015 I served as an Assistant Professor of Economics at Eckerd College, teaching courses including: Econometrics, Labor Economics, and Intermediate Microeconomics. My published research in peer-reviewed academic journals includes a study of the U.S. renewable energy industry and includes international economic impact studies. I have been a witness in Oregon PUC general rate cases: UE 319, UG 287, UG 288, UG 305, UG 325.