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September 27, 2018

***Via Electronic Filing***

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

**RE: Docket No. UG 347 – In the Matter of**
**CASCADE NATURAL GAS CORPORATION, Request for a General Rate Revision.**

Attached for filing are the following documents for Staff Opening Testimony:

Exhibit 100-101
Exhibit 200-202
Exhibit 300-301
Exhibit 400-402
Exhibit 500-501
Exhibit 600-601
Exhibit 700-705
Exhibit 800-801
Exhibit 900-903
Exhibit 1000-1002 and
Exhibit 1100-1102

Confidential and non-confidential work paper will be uploaded to Huddle workspace for parties who have signed Protective Order 18-172.

/s/ Kay Barnes
PUC- Utility Program
kay.barnes@state.or.us

CASE: UG 347
WITNESS: MARIANNE GARDNER

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 100

# Opening Testimony

# September 27, 2018

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

A. My name is Marianne Gardner. I am a program manager 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/101.

**Q. What is the purpose of your testimony?**

A. I am the revenue requirements summary witness for the Public Utility Commission of Oregon Staff (Staff) in this proceeding. I introduce Staff-sponsored adjustments and issues regarding Cascade Natural Gas's (Cascade or Company) filing in this docket, identified as Docket No. UG 347. 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 Staff's proposed adjustments to Cascade's revenue requirement.

Additionally, I provide background regarding specific issues I reviewed, my analysis, and my recommendations.

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

A. Yes. Staff assigned to Docket UG 347 are 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. Staff's recommendations and issues may change after reviewing testimony and analysis by other parties.

**Q. Are there any issues that have been resolved in this case?**

A. Staff, PacifiCorp, the Alliance of Western Energy Customers (AWEC), the Oregon Citizens' Utility Board (CUB), and Hermiston Generating Company L.P. (Hermiston) have reached a settlement agreement in principle that reduces CNG's proposed test year expense. The settlement agreement is not yet executed and its terms will not be discussed in this testimony.

**Q. Did you prepare additional exhibits for this docket?**

A. No.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## PART 1. REVENUE REQUIREMENT

**Q. Please provide background on how the Commission reviews a utility's general rate case filing?**

A. The rates charged by a utility are based on the utility's "revenue requirement." To determine a utility's revenue requirement, the Commission determines for a specified test year: (1) the utility's forecasted gross revenues; (2) the utility's operating expenses to provide utility service; (3) the rate base on which the utility has the opportunity to earn a return; and (4) the rate of return to be applied to the rate base.[1] Once a utility's revenue requirement is established, the Commission determines the rates the utility must charge different classes of customers to collect that revenue requirement, considering the different costs different classes of customers impose on the utility's system.[2]

**Q. What revenue requirement is Cascade asking for in this docket?**

A. Cascade is requesting an increase of $2,310,808 or 3.53 percent. This increase is based on an overall rate of return of 7.33 percent, with a capital structure common equity component of 50 percent, and a return on equity of 9.40 percent.[3] Cascade bases its proposed revenue requirement on a forecasted 2018 test year. Cascade filed its rate case on May 31, 2018 with an anticipated rate effective date of April 1, 2019.

**Q. Please provide a list of the rate case topics that Staff reviewed and introduce the responsible Staff.**

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[1] Order No. 01-787, pp. 5-6.
[2] Order No. 86-477 (1986 WL 1300169).
[3] CNCG/100, Kivisto/3 at 7-10.

A. I have provided a listing of rate topics as well as the adjustments proposed by Staff in Table A.

**Table A.**

| Opening Testimony Exhibit No. | Staff Witness | Issue No. | Issue Description | Revenue | Expense | Rate Base | Revenue Requirement Effect |
|---|---|---|---|---|---|---|---|
| 100 | Gardner | 1 | Franchise Fee Expense | $0 | ($12,801) | $0 | ($13,203) |
| 100 | Gardner | 1 | Franchise Fee - revenue sensitive rate 2.4493% to 2.3857% | | | | (1,604) |
| 100 | Gardner | 3 | W&S, Incentives | | (879,614) | (323,327) | (937,255) |
| 100 | Gardner | 3 | FTEs - placeholder | | | | |
| 200 | Fox | 1 | EDIT | | (177,710) | | (251,091) |
| 200 | Fox | 2a | Plant - Work Asset Mgmt. | | | (162,000) | (15,052) |
| 200 | Fox | 2b | Plant - Bend Phase 7 | | | (433,000) | (40,232) |
| 200 | Fox | 2c | Plant - Bend HP PH1 | | | (90,000) | (8,362) |
| 200 | Fox | 2d | Plant - Madras PH1 | | | (3,437,000) | (319,345) |
| 200 | Fox | 2e | Plant - ERT Replacement - 2018 | | | (1,095,000) | (101,741) |
| 200 | Fox | 3 | Safety Cost Recovery Mechanism | | | | |
| 300 | Fjeldheim | 1 | Distribution Expense | | | | |
| 300 | Fjeldheim | 2 | A&G Expense | | | | |
| 300 | Fjeldheim | 3 | Rate Case Expense | | | | |
| 400 | Gibbens | 1 | Insurance Expense | | | | |
| 400 | Gibbens | 2 | Load Forecast | | | | |
| 400 | Gibbens | 3 | Misc. Revenues | | | | |

| Opening Testimony Exhibit No. | Staff Witness | Issue No. | Issue Description | Revenue | Expense | Rate Base | Revenue Requirement Effect |
|---|---|---|---|---|---|---|---|
| 500 | Glosser | 1 | Gas Storage in Rate Base | | | | |
| 500 | Glosser | 2 | Other Gas Supply Expense | | | | |
| 500 | Glosser | 3 | Underground Storage Expense | | | | |
| 500 | Glosser | 4 | Purchased Gas Expense | | | | |
| 500 | Glosser | 5 | PGA Commodity Sharing Adj. | | | | |
| 600 | Moore | 1 | UM 1816 deferral | | (116,724) | | (120,386) |
| 600 | Moore | 2 | Customer Related Expenses | | | | |
| 600 | Moore | 3 | Environmental Clean Up Expense | | | | |
| 700 | Soldavini | 1 | Cost Allocation | | | | |
| 800 | Rossow | 1 | Misc. A&G | | | | (38,486) |
| 800 | Rossow | 2 | Charitable Donations | | | | (1,287) |
| 900 | Watson | 1 | Implementation of ASU 2017-07 | | | | |
| 900 | Watson | 2 | Pension & Post-Retirement Exp. | | | | |
| 900 | Watson | 3 | Medical Benefit Expense. | | | | |
| 1000 | Zarate | 1 | Low Income Programs | | | | |
| 1000 | Zarate | 2 | Material and Supplies | | | | |
| 1100 | Peng | 1 | Depreciation - Rate Making Overview | | | | |
| 1100 | Peng | 2 | Depreciation Expense | | | | |
| 1100 | Peng | 3 | Depreciation Reserves | | | | |
| 1100 | Peng | 4 | Regulatory Capitalization Policy | | | | |
| 1100 | Peng | 5 | FERC AFUDC Rate Formulas | | | | |
| 1100 | Peng | 6 | Authorized Capital Structure and Rate of Return | | | | |
| **Total Staff-Proposed Adjustments (Base Rates):** | | | | **$0** | **($1,186,849)** | **($5,540,327)** | **($1,848,045)** |

## PART 2. SPECIFIC ISSUES

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

A. I reviewed the portions of the filing related to uncollectible expense, interest synchronization, taxes other than income, workforce levels, wages and salaries, incentives, and working capital. In order to gain additional insight, I reviewed the Company's responses to Staff's Standard Data Requests (SDRs), issued approximately 30 additional data requests (DRs), and reviewed the Company's responses to other intervenors' data requests.

**Q. Are you discussing all of the above issues in opening testimony?**

A. No. As noted above, Staff, intervenors, and the Company have a settlement in principle that includes some of these issues. Testimony in support of the partial stipulation will be filed after Staff's opening testimony is filed. In opening testimony, I address the components of working capital that may be included in CNG's rate base and the appropriate amount of expense that should be included in the test year forecast for taxes other than income, workforce levels, wages and salaries, and incentives. Also, as the summary revenue requirement witness, I am responsible for secondary adjustments to the final revenue requirement resulting from primary adjustments proposed by other Staff and parties. For example, adjustments to plant in rate base may impact property tax expense, depreciation expense, accumulated depreciation expense, and accumulated deferred taxes.

## ISSUE 1. OTHER 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 the wages and salaries issue, which is discussed in a subsequent section of this testimony.

Franchise fees, along with business or occupation taxes, licenses, and similar exactions or costs, are allowed as operating expenses for ratemaking purposes on the condition these costs do not exceed 3.0 percent of gross revenues for a gas utility.[4] 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.

[4] 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.[5] Hence, these property taxes are excluded from the 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 2.449 percent. In its response to Staff DR No. 206, the Company indicated it included in the test year $1,574,278 of franchise fees. The proposed rate of 2.449 percent is the actual 2017 rate.

[5] See ORS 757.355(1).

**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. This results in 2.387 percent versus the Company's 2.449 percent.[6] The 2.387 percent will be used in the test year conversion factor for the revenue requirement. Also, Staff will apply this percent to Staff's adjusted test year revenues to calculate the amount of franchises fees in O&M 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. Yes. According to Order No.18-073, the most recent OPUC order setting the annual fee rate, the rate is set at 0.300 percent; the maximum rate the Commission is allowed to assess utilities.[7] Since this rate is applied to gross revenues, the amount of fees recommended by Staff will be a function of the amount of gross revenues recommended by Staff in subsequent opening testimony.

**<u>Property Taxes</u>**

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

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[6] See Staff electronic workpaper, UG 347 Exh 100 Issue 1 Franchise Fees wp Gardner.xlsx.
[7] See ORS 756.310(3).

A. As provided in its response to Staff DR No. 205, the Company included $1,526,316 in the test year for property taxes. This is the actual amount paid in 2017.

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

A. Staff reviewed the property tax actuals from 2007 through 2017 in the Company's response to Staff DR No. 208. Based on Staff's review, Staff finds the test year property tax expense is reasonable. However, depending on other adjustments to Plant, Staff may propose an adjustment to the final revenue requirement for property tax.

**<u>Summary of Other Taxes</u>**

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

A. Staff concurs with the 0.300 percent OPUC rate in the conversion factor but proposes 2.387 percent for the franchise fee rate.

**Q. What is Staff's recommendation regarding the expense the Company proposes in its test year?**

A. Since both the franchise fees and OPUC fee are revenue sensitive and thus are a function of revenues, Staff will propose an adjustment based on other Staff proposals regarding test year revenues.

## ISSUE 2. WORKING CAPITAL

**Q. Please summarize this issue.**

A. For this issue, Staff examines what the Company has included as working capital in rate base. Generally speaking, working capital is a source of cash to a company for day to day operations.

Q. **Please provide a summary of the Company's filed proposal for working capital.**

A. The Company did not discuss working capital in its testimony. However, in its response to Staff DR Nos. 209 and 210, the Company stated it included in working capital; FERC Account 154, Plant and Operating Supplies, FERC Account 164.2, Liquefied Natural Gas Stored, and FERC Account 165.9, Prepayments – Gas Storage. The total amount of working capital included in rate base for the 2018 test year is $2,812,500.

**Q. Please explain the Commission's historical treatment of working capital?**

A. For ratemaking purposes, the components of working capital are generally rate base items identified as fuel inventory, materials and supplies (M&S) inventory, prepayments, and cash working capital. The Commission typically authorizes utilities to include an allowance for material and supplies in rate base, which has included FERC Account. 154, Plant Material and Operating Supplies; 163, Store Expense Undistributed; 164.2, Liquefied Natural Gas Stored, and 165,

Prepayments – Gas Storage.[8] The Commission's long-standing policy has typically been to disallow gas companies a separate amount for cash working capital. The Commission allows electric companies to include cash working capital in rate base if it is calculated based on a current lead-lag study. In Avista's four most recent rate cases, Docket Nos. UG 246, UG 284, UG 288 and UG 325, Staff stipulated to allowing Avista to include rate base materials and supplies in inventory costs but excluded cash working capital. The Commission adopted those stipulations.[9]

**Q. What is Staff's recommendation?**

A. Staff's recommendation is to allow CNG to include amounts booked to FERC Accounts 154, 164.2, and 165.9 in rate base. Staff witnesses Ms. Zarate, and Ms. Glosser are reviewing the proper amounts to include in rate base for these accounts. Ms. Zarate's review of Account 154 can be found in her Exhibit 1000. Ms. Glosser's recommendation for Accounts 164.2 and 165.9 is located in Exhibit 500. There is no adjustment separate from what Mses. Zarate and Glosser propose.

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[8] *See, e.g., In re California-Pacific Utilities Company,* UF 3275, Order No. 77-394, (1977 WL 438034); *In re Cascade Natural Gas Corporation,* UF 3094 Order No. 74-898 (1974 WL 391913).

[9] *In the Matter of Avista Corporation*, UG 246, Order No. 14-015 at 3; *In the Matter of Avista Corporation*, UG 284, Order No. 15-109 at 3 (April 9, 2015); *In the Matter of Avista Corporation*, UG 288, Order No. 16-076 at App. A, page 3 (February 29, 2016); *In the Matter of Avista Corporation*, UG 325, Order No. 17-344 at 3 (September 13, 2017).

**ISSUE 3. WAGES, SALARIES, INCENTIVES, AND FULL-TIME EQUIVALENTS**

**Q. Please summarize this issue.**

A. For this issue, Staff examines the costs the Company has included in its test year for employee and officer compensation arising from base wages and incentives. These include the wages and incentives for both Cascade's direct employees and those allocated to Cascade from its parent. Additionally, Staff reviews the number of full-time equivalent (FTE) employees the Company proposes for the test year. On an annual basis, an FTE is considered to be 2,080 hours (8 hours per day x 5 days per week x 52 weeks per year).

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

A. According to Mr. Parvinen, "the Company has included in this case $8.9 million for employee salaries and benefits. This amount includes the Test Year (2018) base salaries and base year (2017) incentive pay, medical benefits, and contributions to retirement funds."[10]

**Q. Did the Company include any exhibits or workpapers in its filing that substantiates the $8.9 million amount?**

A. No. However, the Company in its response to SDR No. 92 provided the 2018 test year base wages, incentives, over-time, and FTEs on a total Company basis. Staff followed up and in DR No. 190 and asked the

[10] CNGC/200, Parvinen/22 at 12-16.

Company to confirm that applying the Oregon percent of 26 percent provided in DR No. 93 to the total Company compensation provided in its response to DR No. 92 would closely approximate the compensation charged to the Oregon jurisdiction. Staff requested the Company provide the Oregon allocated amounts if this was not the case. The Company confirmed in its response, "The 26% rate would be a good approximation to use for the amounts provided in DR No. 92 to derive Oregon direct & allocated amounts**."**

**Q. Based on the Company's responses to Staff's data requests, what are the Oregon allocated amounts included in the 2018 test year?**

A. On a total Company basis, the 2018 test year includes approximately $35,036,278 in wages and salaries (base pay), $1,937,329 in incentive compensation (adjusted for the removal of officers' incentives),[11] and $2,442,959 million in overtime.[12] Applying the Oregon allocated rate of 26 percent, the Oregon allocated test year amounts for base pay, incentive compensation, and over-time are as follows:

| 2018 Test Year | Base Wages | Over-time | Incentives | Total |
|---|---|---|---|---|
| Total Company | $35,036,278 | $2,442,959 | $1,937,329 | $39,416,566 |
| Oregon Allocated % | 26% | 26% | 26% | 26% |
| Oregon Allocated | $9,109,432 | $635,169 | $503,706 | $10,248,307 |

[11] CNGC/300, Peters/6 at 6-9.
[12] Staff/102, Cascade Response to Staff DR Nos. 92 and 192.

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

A. The Commission typically uses Staff's three-year wage and salary model (W&S Model) to estimate expenses for non-union wages and salaries.[13]

As a starting point, Staffs model uses the utility's actual 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[10] to adjust wages and salaries for each of the three subsequent years to establish a forecast of test-year wage and salary levels. If the utility's projected wage and salary level is within ten percent of Staffs projection, the difference between projections is shared between customers and shareholders. Outside the ten-percent band, shareholders keep all of the benefit or pay all the cost.

The W&S Model incorporates actual market-based data by using the All-Urban CPI index to adjust historic wages and salaries.[14] Notably, local economic conditions are represented in the All-Urban CPI, as the Bureau of Labor Statistics includes prices in Oregon when it conducts its survey. [15] The Commission has concluded that adjusting payroll levels by changes in inflation provides the employees the same real level of compensation as in the base

[13] See e.g., *In the Matter of PacifiCorp*, UE 116, Order No. 01-787 at 40 (September 7, 2001).

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

[15] Order 01-787 at 40; *In the Matter of Northwest Natural*, UG 132, Order No. 99-697 at 43 (November 12, 1999). See also *In the Matter of PGE*, UE 102, Order 99-033 at 61 (January 27, 1999); *In the Matter of PGE*, UE 88, Order No. 95-322 at10 (March 29, 1995).

year, and provides an incentive to companies to minimize labor costs.[16] Further, sharing the difference between the two payroll projections equally between ratepayers and shareholders also allows for some adjustments to reflect changes in market conditions without allowing unchecked escalation.[17]

Rather than using All-Urban CPI for union wages, the Commission typically ties test year union payroll to negotiated wage increases as set forth in the union contract.[18]

For incentives, Commission policy traditionally disallows 100 percent of officers' bonuses, which are typically based on increased earnings.[19] 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 shareholders and ratepayers). Union bonuses are treated in the same manner as non-union bonuses.[20]

**Q. How do the Company's adjustments to salaries, wages and incentives differ from those Staff typically makes in a general rate case?**

A. Staff explains the differences by each component of Staff's W&S Model below.

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[16] Order 01-787 at 40.

[17] Order No. 95-322 at 10.

[18] See Order No. 99-697 at 43.

[19] See Order No. 99-033 at 62, *In the Matter of the Application of US West*, UT 125, Order No. 97-171 at 74-76 (May 19, 1997).

[20] See Order 99-697 at 44-45; Order 99-033 at 62.

***Escalation***

**Q. Please explain the Company's proposal regarding the escalation of base payroll.**

A. As explained in its testimony, for non-union employees CNG escalated base pay for the calendar year 2017 by 4.00 percent for the 2018 test year. The 4.00 percent increase was the actual increase effective January 1, 2018.[21]

Staff, consistent with Staff's W&S Model, escalated the wages and salaries from the 2015 historical base year to a projected 2018 test year using the All-Urban CPI. For union employees, Staff's escalation is based on the last contracted rate increase of three percent as provided by the Company in its response to Staff DR No. 94. Staff then determined the difference between its projection of test year amounts and the Company's and applied the sharing percentages.

As noted above, if Staff's projection is less than the Company's test year amount, the sharing test allows the Company to share 50/50 the lesser of the difference between the Company's filed proposal and Staff's calculated projection or a 10 percent band around Staff's calculated projection.[22] In this case, Staff accepts the Company's proposal for officer salaries but for the other employee categories, the difference between the Company's filed proposal and Staff's calculated projection was the lesser amount. CNG's wage and salary

[21] CNGC/300, Peters/5 at 18-32.

[22] See Staff electronic workpaper, CNG UG 347 Exh 100 Issue 3 Wage & Salary model CONF wp Gardner.xlsx.

projection exceeds Staff's projection on a total Company basis by $1,494,566. Staff multiplied this difference by 50 percent for sharing. Staff then applied the Oregon-allocation percentage of 26 percent to derive the adjustment for the Oregon jurisdictional test year.

**Q. What is Staff's recommendation regarding the escalation of salaries and wages to include in the 2019 test year?**

A. Staff recommends reducing the base year salaries and wages by ($718,552) allocated as ($553,285) O&M expense and ($165,267) capital. Also related to this are small adjustments for payroll taxes and depreciation of ($62,337) and ($7,228), respectively.[23]

***FTEs***

**Q. Please provide the background for this issue.**

A. CNG's 2018 test year includes 382 FTE[24] on a total Company basis. This is an increase of 35 FTEs from 2017 through 2018.[25] Using the Company's Oregon allocation percentage of 26 percent, this is an approximately nine FTE increase to Oregon.

**Q. Did the Company explain the increase in FTE from 2017 through 2018 in its testimony?**

A. The Company explained an increase of seven FTE on a system basis. The Company rationale for the increase was for crew to support maintenance

[23] See Staff electronic workpaper, CNG UG 347 Exh 100 Issue 3 Wage & Salary model CONF wp Gardner.

[24] Staff/102, Cascade Response to Staff DR No. 92.

[25] Ibid.

and new construction and one engineer to support capital projects.[26] The workpapers of Cascade witness Ms. Peters show that Oregon received an allocation of approximately 25 percent of four positions and 100 percent of three positions dedicated to Bend operations.[27]

**Q. Please describe Staff's analysis of the Company's increase in FTE.**

A. Since the Company's testimony explained only seven of the total increase of 35 FTE on a total Company basis, Staff inquired further of the Company in DR No. 193. The Company explained that the other employees were replacement employees.

**Q. Did the Company explain what it meant by "replacement employees"?**

A. No. Staff has followed up with a data request but the response will not be received until after opening testimony is filed.

**Q. What is Staff's recommendation regarding the number of FTE proposed for the test year?**

A. Since Staff has further discovery on this topic, Staff does not have an adjustment for opening testimony. However, Staff may propose to exclude employees that are not hired by November 2018 and also may propose an adjustment to FTE based on adjustments to new plant. Additionally, if Staff discovers that any of the "replacement employees", include an FTE count for a vacant or open position or to double-cover a position, e.g. knowledge transfer,

[26] CNGC/300, Peters/5 at 23-25, and 6 at 1-5.

[27] CNGC/Exhibit 301-306 Peters workpapers – Excel.xlsx, tab New Positions Adjustment.

planned succession etc., Staff may recommend an adjustment to exclude replacement employees.

***Incentives***

**Q. Please explain the Company's proposal regarding the inclusion of incentive pay in its Oregon jurisdictional test year?**

A. The Company proposes to include 100 percent of non-officer employee incentives. The estimated test year incentives are based on 2017 actual incentives paid.[28] The Company position is that incentives are an "integral component of market compensation."[29] The Company contends, "it is essential that we pay our employees compensation at market, in order to attract and retain a qualified workforce. Therefore, it is fair and appropriate that these costs be included in customer rates."[30]

**Q. Did Staff review incentives as a component of total compensation?**

A. Yes. Staff reviewed the median pay analysis the Company provided in its responses and a third-party review of base compensation and incentive compensation conducted in 2013 by Aon Hewitt provided in response to Staff's data requests. The Company's pay analysis included base pay and incentive pay. Staff finds that both base pay and incentives for the non-bargaining employees and bargaining employees appear to be appropriate as compared to the peer data.

[28] CNGC/200, Parvinen/22 at 19-25.
[29] CNGC/200, Parvinen/23 at 1-2.
[30] CNGC/200, Parvinen/23 at 2-4.

**Q. What is Staff's position regarding the level of incentives included in the test year?**

A. As Staff mentioned earlier in its testimony, Commission policy traditionally disallows 100 percent of officers' incentives and a portion of non-officer employee incentives. Non-officer incentives are disallowed at 50 percent if they are based on non-financial metrics and 75 percent if the incentives are based on financial performance measures. The Commission's policy appropriately matches costs and benefits as officers' incentives hinge on meeting shareholders' financial expectations. The policy as it relates to non-officers is more flexible and recognizes that both customers and shareholders benefit from high-achieving employees whose daily jobs impact both customers' quality of service and the Company's bottom line.

**Q. Does the Company object in testimony to the Commission's incentive policy?**

A. Yes. The Company disagrees with the Commission's view that there should be a sharing of incentives between customers and shareholders.[31] Alternatively, the Company suggests, if the Commission does not reconsider its position in this rate case, the Commission "open a generic proceeding, including all stakeholders to reconsider the issue."[32]

**Q. What is Staff's response to the Company's arguments opposing the Commission's incentive policy?**

[31] CNGC/200, Parvinen/23 at 4-8.

[32] CNGC/200, Parvinen/23 at 10-11.

A. The Company is correct that in the past the Commission has included only a portion of employees' incentives in rates. The Commission's policy disallowing portions of incentives for rate-making purposes is well documented in past orders and Staff practice. As noted in the Commission's disposition in Order 97-171, whether compensation as a whole is reasonable is measured against the market and is a distinct issue from whether customers should pay for incentives in rates.

> The record shows that USWC's base salaries before bonuses are within a reasonable range, as is USWC's compensation including bonuses. Because its compensation is reasonable compared to the market, USWC concludes that its expense for management and executive bonuses is reasonable. USWC conflates two separate issues. The level of overall compensation is reasonable compared to the market. That does not determine whether it is reasonable to ask ratepayers to fund bonuses with the declared goals of USWC's incentive plans.[33]

2) The fact that incentives could benefit both shareholders and customers is not at odds with Commission policy. That is evident in the sharing methodology the Commission policy sets forth. Rather it is the metrics, goals, and targets the plan is based upon that give rise to the disallowance.

In Docket No. UT 125, Staff asserted that bonuses paid by US West Communications (USWC) under certain plans were based on achieving financial, business, and corporate goals. The USWC plans in question included the following metrics (1) Earnings before Interest Taxes, Depreciation,

[33] *In the Matter of the Application of U S WEST Communications, Inc., for an Increase in Revenues,* UT 125, Order No. 97-171.

and Amortization (EBITDA); (2) USWC Net Income; and (3) Business Unit Results & Strategic Measures, Customer Service, Customer Loyalty, increase in USWC stock price, and stock dividend growth. Staff proposed to disallow all of the bonuses associated with these plans. In the disposition of this issue, the Commission stated as follows in Order 97-171:

> We note that our disallowance is not based on the manner in which compensation is administered but on the purpose for which the bonuses are awarded. We also note that this conclusion does not prevent USWC from paying bonuses; it merely dictates that bonuses be paid from funds that would go to shareholders, not from funds provided by ratepayers. Therefore, we do not believe that the resolution of this issue places USWC at a competitive disadvantage.* * * If in a future rate case USWC submits employee incentive plans with goals that would benefit both ratepayers and shareholders, we will include those expenditures in revenue requirement.[34]

The sharing principle is also upheld by the Commission in Order No. 99-033:

> Staff also proposed an adjustment of $1,273,200 to the Officer Incentive Plan. PGE claims that this adjustment is inconsistent with past Commission practice (in UE 88, for example), where the Commission allowed inclusion in revenue requirement of the 25 percent portion of the Officer Incentive Plan applicable to non-officers. Staff now accepts the allowance of a portion of the plan covering non-officer employees and asks that the Commission approve the following principle for incentive pay:
>
> One-half of Our Teamworks expense, all of the Officers portion of the Officer Incentive Plan and seventy-five percent of the non-officer portion of the OIP pay should be excluded from utility rates, consistent with past Commission practice.

**12. Commission Disposition**

[34] Ibid.

> The Commission adopts Staff's principle as set out above.[35]

3) The Commission does not dictate an appropriate compensation policy for any of the regulated companies. Rather, the Commission allows in rates those costs that result in just and reasonable rates for customers. The Commission's disallowance of certain incentive plans reflects the fact that customers and shareholders benefit in different proportions to the plan. Since the Commission applies the same policy across all of the regulated companies under its regulatory authority, it does not set them at a competitive disadvantage from each other.

4) Disallowing a portion of incentives included in the historical base year rate base is not an extension of the Commission incentive policy. Staff's Wage & Salary Model does allocate its proposed adjustment between O&M and capital based on the O&M/Capital allocation percentage provided by the Company.[36]

**Q. What is Staff's recommendation regarding the amount of incentives in the test year?**

A. Staff recommends reducing the incentives included in the Company's test year Additionally, Staff recommends reducing plant in rate base for the portion of incentives capitalized in the historical rate base contrary to Commission policy.

**Q. Has Staff proposed a reduction to plant for incentives capitalized in rate base between rate cases prior to this rate case?**

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[35] *In the Matter of the Application of Portland General Electric Company for Approval of the Customer Choice Plan,* UE 102, Order No. 99-033.

[36] Staff/102, NW Natural Responses to Staff DR No. 93.

A. Yes. In a recent Portland General Electric (PGE) rate case, Staff discovered that in between rate cases, PGE was continuing to capitalize officer incentives and other non-officer performance-based incentives in rate base. Staff asserted that not only should the disallowed incentives capitalized in plant for the test year be removed but the historical base year should be reduced for the disallowed incentives PGE had continued to capitalize in plant. Therefore, Staff proposed to adjust the test year rate base for performance related incentives included in the plant balance.[37] Staff proposed the same treatment in NWN's general rate case UG 344.[38]

After application of the sharing test, Staff recommends a reduction in CNG's test year incentives of ($333) thousand, allocated between O&M and capital costs as ($257) thousand and ($77) thousand, respectively. Also, Staff proposes to reduce plant in rate base for performance related incentives capitalized for the 2017, the interim year since Docket No. UG 305, the Company's last general rate case. This adjustment reduces plant in rate base by ($81) thousand.[39]

**Q. Does this conclude your testimony?**

A. Yes.

[37] UE 283 Stipulating Parties/200, Gardner-Higgins-Jenks-Macfarlane-Mullins/6 (settling issue related to capitalization of incentives).

[38] UG 344 Opening Testimony/Staff/100, Gardner/42 at 15-17.

[39] See Staff electronic workpaper, UG 347 Exh 100 Issue 3 Wage &Salary model CONF wp Gardner.

CASE: UG 347
WITNESS: MARIANNE GARDNER

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 101

# Witness Qualifications Statement

# September 27, 2018

**WITNESS QUALIFICATION STATEMENT**

NAME: Marianne Gardner

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Revenue Requirement Analyst
Energy Rates, Finance and Audit Division

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

EDUCATION: Master of Business Administration
Oregon State University, Corvallis, Oregon

Bachelor of Science in Accounting
Montana State University, Bozeman, Montana

CPA, Oregon

EXPERIENCE: I have been employed by the Public Utility Commission of Oregon since March 2013, with my current position being a Senior Revenue Requirement Analyst, in the Energy - Rates, Finance and Audit Division. My responsibilities include research, analysis, and recommendations on a range of cost, revenue and policy issues for electric and natural gas utilities. As the revenue requirement summary witness, I have provided testimony in dockets UE 263, UG 246, UE 283, UE 294, UG 284, UG 287, UG 288, and UG 305.

I have approximately 20 years of professional accounting experience, including:

- Thirteen years as a cost accountant with responsibilities including cost accounting, budgeting, product costing, and the preparation of management reports;

- Four years experience in public accounting working in the areas of audit, tax and financial accounting for individual and small business clientele; and,

- Three years experience in non-profit accounting for an agency administrating funds under the Federal Job Training Partnership Act.

CASE: UG 347
WITNESS: JOHN L. FOX

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 200

# Opening Testimony

# September 27, 2018

**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 S.E., 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. My testimony addresses the general areas of utility plant, income taxes, and the proposed Safety Cost Recovery Mechanism (SCRM).

**Q. Did you prepare an exhibit for this docket?**

A. Yes. I prepared the following exhibits:

Exhibit Staff/202, Data Request Responses

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1. INCOME TAXES

**Q. Please provide a summary of the Company's filed proposal for income taxes.**

A. The Company's request is summarized in the following table:

| **State & Federal Income Tax Recap:**<br>CNGC Exhibits 301-303 | | |
|---|---|---|
| Base year tax expense (2017 Results of Operations) | | $ 1,875,733 |
| Reduction in base year federal tax rate from 35% to 21% | (597,365) | |
| Amortization of Protected Excess Deferred Income Taxes (EDIT) | (382,556) | |
| Amortization of Unprotected Excess Deferred Income Taxes | (177,710) | |
| All other base year adjustments | (49,018) | |
| | | (1,206,649) |
| Test year adjusted total | | 669,084 |
| Taxes due to requested $2.3 million revenue increase | | 604,830 |
| State & Federal Income Taxes after proposed revenue increase | | $ 1,273,914 |

The other base year tax reductions of ($49,018) are the tax effects of customary rate case adjustments to base year operating results as shown in the following column taken from Exhibit CNGC/304. Staff may propose adjustments to these amounts based on Staff review of each specific issue in testimony provided by other Staff witnesses and will not be further discussed in my testimony:

| CNGC Exhibit 304 Column: | |
|---|---|
| Uncollectibles Expense (a) | $ 11,761 |
| Removal 50% Membership Fees (b) | 9,093 |
| Promotional Advertising Adjustment (c) | 3,101 |
| Interest Coordination Adjustment ( d ) | (53,858) |
| PGA Commodity Sharing Adj. (e) | 53,490 |
| Annualizing Wage Rate Adjustment (f) | (8,034) |
| 2018 Revenue Adjustment (g) | 301,741 |
| 2018 Wage Adjustments (h) | (61,431) |
| 2018 New Positions (i) | (69,064) |
| Officer Incentive Comp Adj (j) | 83,451 |
| 2018 Plant Additions (k) | (169,481) |
| Inflation Factor Adj (l) | (37,382) |
| Miscellaneous Charge Changes (m) | 6,652 |
| Depreciation Expense Adj (n) | (64,844) |
| A&G Adjustment (o) | 1,522 |
| UM 1816 Deferral Amortization (q) | (31,520) |
| Rate Case Costs (r) | (24,214) |
| | $ (49,018) |

The Company's remaining adjustments to base year results are due to the provisions of federal Public Law 115-97, known as the Tax Cuts and Jobs Act (TCJA).

**Q. Please explain the Commission's historical treatment of income taxes.**

A. The Commission's historical treatment is governed by ORS 757.269, including application of the provisions of Statement of Financial Accounting Standards (SFAS) 109, Accounting for Income Taxes. For rate making purposes, Oregon is currently fully normalized, meaning that it does not currently "flow through" any of the timing differences[1] that result from deferred income taxes. As a

[1] "Timing differences" means "the differences between the amounts of expenses or revenues recognized for income tax purposes and amounts of expenses or revenues recognized for rate making purposes, which differences arise in one time period and reverse in one or more other time periods so that the total amounts of expenses or revenues recognized for income tax purposes and for ratemaking purposes are equal." 18 C.F.R. § 35.24(d)(2).

result of being fully normalized, the Commission does not pass on to ratepayers any current tax benefits of temporary deferrals that result in reduced current income tax. Similarly, when temporary deferrals reverse, the increased current income tax is not passed on to ratepayers. Income tax normalization complies with generally accepted accounting principles and causes a rate base adjustment that is amortized over the tax life of the timing difference.

Consistent with Internal Revenue Code (IRC) Sections 168(f)(2) and 168(i)(9) (Normalization Rules for Public Utilities) and ORS 757.269(1), public utilities are required to normalize federal income taxes for revenue requirement purposes. Normalization of federal income taxes means that a regulated public utility that uses accelerated depreciation for tax purposes must record in rate base a related deferral of taxes that arises from the difference between book depreciation and tax depreciation. According to IRC Sec. 168(i)(9)(A):

> In order to use normalization method of accounting with respect to any public utility property for purposes of subsection (f)(2)—
>
> (i) the taxpayer must, in computing its tax expense for purposes of establishing its cost of service for ratemaking purposes and reflecting operating results in its regulated books of account, use a method of depreciation with respect to such property that is the same as, and a depreciation period for such property that is no shorter than, the method and period used to compute its depreciation expense for such purposes; and
>
> (ii) if the amount allowable as a deduction under this section with respect to such property (respecting all elections made by the taxpayer under this section) differs from the amount that would be allowable as a deduction under section 167 using the method (including the period, first and last year convention, and salvage value) used to

> compute regulated tax expense under clause (i), the taxpayer must make adjustments to a reserve to reflect the deferral of taxes resulting from such difference.

Also, ORS 757.269 (1) states "[s]ubject 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 operation of the utility." According to subsection (3):

> During a ratemaking proceeding conducted under ORS 757.210 for an electricity or natural gas utility that pays taxes a 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.

**Q. Please describe Staff's analysis of the Company's proposal for income taxes.**

A. Staff evaluated both the Company's ongoing application of SFAS 109 and the impact of TCJA on the 2018 test year expense.

**Q. Would Staff please provide the main impact of the 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.

The largest component requiring re-measurement of ADIT balances 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. Are there other Commission dockets open related to the Company's implementation of TCJA?**

A. Yes. As noted in the Company's testimony,[2] the Company filed an application to defer the savings associated from TCJA implementation for 2018.[3] There is

[2] CNGC/200, Parvinen/11, 13.
[3] 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.

also a related docket for an application for deferral filed by Staff for to protect the interests of rate payers.[4]

**Q. Is the Company requesting to return the interim 2018 TCJA benefits to rate payers in this general rate case?**

A. No. The benefits may be returned pursuant to the aforementioned dockets. Staff is open to including those benefits in rates in this case in the interest of accelerating the return of benefits to rate payers.

**Q. How are TCJA benefits returned to ratepayers in the 2019 test year under Cascade's rate case filing?**

A. The change in statutory rate from 35 percent to 21 percent is accomplished by an initial downward adjustment to base year tax expense of ($597,365) and adjusting the conversion factor calculation to reflect the lower 21 percent rate. Customers are also due a refund for income taxes collected in rates in prior years that have not yet been paid by the Company. This is accomplished by revaluing the ongoing accumulated deferred income tax (ADIT) accounts at the new lower rate and moving the resulting excess deferred income taxes (EDIT) to a new regulatory liability account. The EDIT will be amortized into rates in 2019 and future years.

**Q. Is Staff proposing to modify the Company's reduction of base year taxes from 35 percent to 21 percent or the conversion factor?**

A. No.

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[4] See *In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Application to Defer Changes in Cascade Natural Gas Company's Federal Tax Obligations Resulting from H.R.1 - Tax Cuts and Jobs Act*, Docket No. UM 1922.

**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"[5], 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. The Company is proposing to return of ($382,556) for protected EDIT and ($177,710) for unprotected EDIT in the test year revenue requirement.

**Q. Is Staff proposing to modify the Company's calculated return of protected EDIT and if not, why?**

A. No. 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)[6] = $1,699,492 / 41,264,063 = 4.12%

[5] 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).
[6] CNGC/203, Parvinen/1.

- Composite useful life[7] = 100 / 32.1 years = 3.12%

The system wide ARAM amount is allocated to Oregon proportional to Oregon's share of plant assets.[8] Staff considers both the percentage rate of return and method to allocate Oregon benefits to be reasonable.

**Q. Is Staff proposing to modify the Company's calculated return of unprotected EDIT and if so, why?**

A. Yes, Staff is proposing that Oregon's share of unprotected EDIT be returned to ratepayers over five years instead of ten years. This will decrease tax expense by ($177,710). The Company proposed to return the unprotected EDIT over a 10 year period and puts forth the following rationale:[9]

- The average period for each item contained in the Non-Plant EDIT works out to approximately ten years.
- For consistency each of the utilities within the MDU umbrella is requesting ten years.
- Washington has accepted the ten-year amortization in its most recent rate case settlement (UG-170929).

Staff asserts the Company's rationale is irrelevant.

In Oregon, the revenue requirement includes taxes at the full statutory rate regardless of whether they are deferred or not. Accordingly, rate payers have already funded the accumulated deferred taxes in full at the statutory rate of

[7] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Depreciation Study on All Gas Plant as of December 31, 2013*, Docket No. UM 1727, Appendix B, Page 1.
[8] CNGC/203, Parvinen/1 and Staff DR No. 122 e.
[9] Staff DR No 122 d.

35 percent. The unprotected EDIT became due and payable to Oregon rate payers on the day President Trump signed the TCJA into law. Furthermore, according to the IRS, the benefits can be returned to rate payers using any reasonable method. Since the Company already has the cash and there is no constraint on return, it is available to be returned immediately.

**Q. Why is Staff recommending five years?**

A. There are two reasons. First, refunding the entire amount immediately would decrease income tax expense by ($177,710) x 9 years = ($1,599,390). As the requested revenue increase in this case is $2.3 million[10] returning the entire amount immediately would negate a large portion of the rate increase and likely cause cash flow problems. However, the Company should be able to absorb an increased refund in the amount of $177,710 with little difficulty.

Second, the Company is asking to establish a Safety Cost Recovery Mechanism for five years. If this is authorized, it would likely reduce the frequency of the Company's general rate case filings. The Commission will not have the opportunity to reset the amount of amortization in the event a general rate case is not filed for some time. Accordingly, it is in the ratepayer's interest to accelerate the return of tax benefits now.

**Q. How is EDIT reflected in rate base?**

[10] CNGC/100, Kivisto/3 and CNGC/301, Peters/1.

A. EDIT continues to be reflected in a rate base adjustment for deferred accumulated income taxes until amortized. This is the correct method and is reflected in the Company exhibits.[11]

**Q. Does Staff propose an adjustment to the proposed 2018 test year revenue requirement?**

A. Yes. As discussed above, Staff recommends that unprotected EDIT be returned to rate payers over five years instead of 10 years. This adjustment will decrease test year income tax expense by ($178) thousand dollars.

[11] Amortization of $560,266 in CNGC/203, Parvinen/1 and a corresponding decrease of Deferred Accumulated Income Taxes in CNGC/304, Peters/1.

## ISSUE 2. GROSS PLANT ADDITIONS

**Q. Please provide a summary of the Company's filed proposal for gross plant additions.**

A. The Company reports $219.983 million of plant in service as of December 31, 2017.[12] The Company is requesting an additional $24.552 million in gross plant additions during the 2018 test year. This includes $11.4 million of projects that would be subject to the requested Safety Cost Recovery Mechanism were such a mechanism currently in place.

**Q. Please explain the Commission's historical treatment of plant additions.**

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 (March 31, 2019 in this case). Additionally, a prudence review must determine whether the Company's actions, based on all it that it knew or should have known at the time, were reasonable and prudent in light of the circumstances which then existed. "Any investment found to be unreasonable is deemed imprudent and subject to partial or full disallowance."[13]

**Q. Please describe Staff's analysis of the Company's proposal for gross plant.**

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[12] CNGC/301, Peters/1.
[13] See *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision*, Docket No. UE 246, Order No. 12-493 pp 25-31 (Dec 20, 2012).

A. Staff's review primarily focuses on proposed 2018 plant additions over $150,000 in value. Staff issued a series of data requests (DRs) to gather additional information for the following purposes:

- Verify project costs included in the rate case.
- Verify that projects will be presently used for providing utility costs to customers by rate effective date.
- Verify the costs are properly allocable to Oregon rate payers.
- Provide evidence that the costs to be included in rate base were prudently incurred.

**Q. In general, what was the quality of information provided by the Company?**

A. Poor. For example, Staff DR No. 134 requested the following information for each project over $150,000:

a. Comprehensive cost-benefit analysis of whether and when investment should be built;

b. Evaluation of range of alternative build dates and the impact on reliability and customer rates;

c. Evidence on the likelihood of disruptions based on historical experience;

d. Evidence on the range of possible reliability incidents;

e. Evidence about projected loads and customers in the area; and

f. Consideration of alternatives, including use of interruptibility or increase demand-side measures to improve reliability and system resiliency.

In response, the Company provided a series of memos for each project ranging in length between one paragraph and several pages that did not include most of the information requested.

**Q. Did Staff issue additional data requests?**

A. Yes, a number were very specific. For example, Staff DR No. 265(b) requested:

i. Describe in detail the increased capacity in terms of pipe size, operating pressure, and gas delivery volumes.

ii. Specifically identify the existing and future expected demand the increased capacity will fulfill, including but not limited to information by year, number of customers, customer location, and delivery volumes.

iii. Provide a detailed explanation as to why the additional capacity is necessary in 2018 rather than in a future year.

iv. Provide all studies, analysis, modeling, or other documentation supporting the increased demand projections.

v. Provide specific references to page numbers in the current IRP, previous IRP, or any other commission filing discussing the project.

**Q. In general, what was the quality of information provided by the Company in response to the follow up requests?**

A. Better, but still very brief narrative descriptions and presumably not "***all*** studies, analysis, modeling, or other documentation." Staff simply finds it difficult to understand how the Company can be making multi-million dollar investment decisions based solely on the information provided.

**Q. How does this response pattern affect Staff's ability to evaluate the prudence of the Company's proposed investments?**

A. It is Staff's responsibility to make a recommendation for Commission consideration. A prudence review is based on all the information that the Company knew or should have known at the time, in light of the circumstances. Yet the Company has not been responsive in providing that information.

**Q. Do any of the proposed projects over $150,000 for 2018 add capacity?**

A. Yes, several projects will add capacity.[14]

- FP-200689 RPL; 6" HP, BEND HP PH1
  - Upgrade modeled with both 8" and 12". Company decided to go with the larger size due to growth in the Bend area.
- FP-306989 UMATILLA 2" REINFORCEMENT
  - Purpose of the project is to provide a 2nd feed and facilitate maintenance on the existing feed.
- FP-306997 RPL; 4" HP, MADRAS PH1
  - Company states that the additional cost to install 6" vs 4" line is minimal.

[14] See Staff/200, Fox/14, Company Response to Staff DR No. 265 (providing capacity information).

**Q. Does Staff have reason to believe the cost of any of the proposed projects over $150,000 for 2018 will exceed the economic value of the project or will result in unreasonable operating costs?**

A. No. However, Staff notes that an installed gas distribution project is an illiquid asset and the value could only be accurately determined by a third-party sale of all or a portion of the Company's system or perhaps an appraisal. Another possibility for estimating the economic value would be an analysis of the net present value of future gas deliveries associated with the project.

**Q. Is Staff recommending a prudence disallowance for project costs for distribution system improvement projects in this case?**

A. No. Staff recognizes that distribution system improvements are costly and construction activities are inconvenient and disruptive for the communities involved. Accordingly, some level of capacity increase beyond the current system demand is prudent and Staff finds the Company is acting reasonably under the circumstances. Despite the Company's lack of responsiveness in this case, Staff is recommending that the Commission allow the costs into rate base. However, Staff expects improved documentation and responsiveness in future rate cases.

**Q. Does Staff propose any adjustment to the proposed 2018 test year rate base?**

A. Yes. Staff finds that the amount in gross plant should be reduced for several proposed projects. There are several overarching reasons for Staff's recommendations including projects not being used and useful, amounts

exceeding estimates previously reported to the Commission, and changes in the Company's estimated project costs after the rate case exhibits were prepared. The specific projects for which I propose a disallowance are:

FP-101480 UG- Work Asset Management

FP-200688 Bend Pipe Replacement Phase 7

FP-316697 RP; 4" ST; Bend; 2,500' PH 7 Sec 1

FP-200689 RPL; 6" HP, BEND HP PH1

FP-306997 RPL; 4" HP, MADRAS PH1

FP-308022 ERT Replacement – 2018

**Q. What is Staff's recommendation regarding project FP-101480 UG-Work Asset Management?**

A. Staff recommends a test year rate gross plant reduction of ($162) thousand dollars. The Company's response to Staff DR No. 134 indicates this project is for implementation of the Maximo work management system. The Company's response to Staff DR No. 265 indicates the Company is in the initial stages of a five year, $31 million dollar plan to implement the system across MDU's three major utility brands. Accordingly, costs incurred to date are not presently used for providing utility service to customers and should be removed from rate base.

**Q. What is Staff's recommendation regarding projects FP-200688 Bend Pipe Replacement Phase 7 and FP-316697 RP; 4" ST; Bend; 2,500' PH 7 Sec 1?**

A. Staff recommends a test year rate gross plant reduction of ($433) thousand dollars. This is the difference between the amount included in the rate case

and the amount included in the Company's annual safety plan. These projects are in the 7th year of a multi-phase effort to replace 1930's era gas mains in the downtown Bend area. The Company's responses to Staff DR Nos. 134 and 267 indicate the first phase (FP-316697) was completed and placed into service on May 29, 2018, and the second phase is currently under construction and scheduled to be placed into service on September 18, 2018.

Staff's primary concern regarding this project is prospective cost over-runs. The cost for both phases is $3.033 million. The Company's revised safety plan was filed 10 days before the rate case, on May 21st, showing a phase 7 total cost of $2.6 million. The Company's response to Staff DR No. 133 shows a projected total of $3.155 million and the project summaries provided in response to Staff DR No. 134 show yet another set of numbers. Furthermore, Cascade's response to Staff DR No. 133 shows $1.8 million of project costs are not scheduled to be paid until December 2018. The Company's response to Staff DR No. 266 indicates that excess funds are being shifted from the Madras project in anticipation that additional funds may be needed.

Staff concludes that the numbers provided are inconsistent and speculative at this point and recommends that that the project cost included in the test year gross plant be reduced to match the UM 1899 figure of $2.6 million to protect rate payers from being overcharged.

**Q. What is Staff's recommendation regarding project FP-200689 RPL; 6" HP, BEND HP PH1?**

A. Staff recommends a test year rate gross plant reduction of ($90) thousand dollars. This project replaces a portion of the high pressure line into the City of Bend. The project is currently under construction and scheduled to be completed on September 14. Staff has concerns similar to those discussed above about the various numbers being reported for this project; rate case cost $1.790 million, safety plan cost $1.7 million, response to Staff DR No. 133 $2.011 million, and response to Staff DR No. 134 $1.793 million. Per the Company's response to Staff DR No. 133, no payments are scheduled until December.

Accordingly, Staff concludes that the numbers provided are also inconsistent and speculative at this point and recommends that that the project cost included in the test year gross plant be reduced to match the figure of $1.7 million included in Cascade's safety plan (Docket No. UM 1899) to protect rate payers from being overcharged.

**Q. What is Staff's recommendation regarding project FP-306997 RPL; 4" HP, MADRAS PH1?**

A. Staff recommends a test year rate gross plant reduction of ($3.437) million dollars. This project replaces a portion of the high pressure line into the City of Madras. The rate case cost of the project is $5.540 million. The Company's response to Staff DR No. 265 indicates the project scope has been reduced and the project cost is now projected to be $2.103 million. Therefore, the balance should be removed from the rate case.

**Q. What is Staff's recommendation regarding project FP-308022 ERT Replacement – 2018?**

A. Staff recommends a test year rate gross plant reduction of ($1.095) million dollars. This project replaces automated meter reading equipment that is approaching the end of its useful life. The rate case cost of the project is $3.486 million. The Company's response to Staff DR No. 267 indicates that only a portion of the meters are being replaced in 2018 (36,500 of 53,000 total). The DR response also provides a unit cost of $49-$82. Using the midpoint unit cost of $65.50, the value of 36,500 installed units is $2.391 million. The cost of the uninstalled units should be removed from the rate case.

## ISSUE 3. SAFETY COST RECOVERY MECHANISM (SCRM)

**Q. Please provide a summary of the Company's filed proposal for a Safety Cost Recovery Mechanism.**

A. The Company is proposing to establish a SCRM for five years beginning in 2019. Annual project costs are expected to be between $10 million and $13 million per year. Annual rate increases will be capped at 2.5 percent and only occur to the extent that annual capital investments exceed annual depreciation and will be subject to an annual earnings test.[15] The Company proposes to request recovery of costs on an annual basis with the filing to occur on November 1 each year and rates to be effective on February 1 of the following year.[16]

**Q. Did the Company subsequently update the estimated project costs to be included in the SCRM?**

A. As further discussed below, the Company's response to Staff DR No. 280 revises this project volume to be $6-8 million per year.

**Q. Please explain the Commission's historical treatment.**

A. In 2015, the Commission opened an investigation into the recovery of safety costs. The investigation concluded with a stipulation amongst Staff, the gas LDCs, and stakeholders agreeing to guidelines to govern proposals for safety cost recovery mechanisms used between general rate cases. The Commission adopted the stipulation and guidelines (hereinafter referred to as "UM 1722

[15] CNGC/200, Parvinen/17-18.
[16] CNGC/200, Parvinen/20.

guidelines" or "guidelines"). [17] Staff views meeting the guidelines as a starting point for review only. Commission approval should be based on the merits of the particular proposal at hand. Staff's step by step analysis of the UM 1722 guidelines is discussed below.

**Q. Does Staff support approval of the SCRM proposed by Cascade?**

A. No. At this time Staff does not support approval of the SCRM. Cascade has not identified significant investments necessary to address infrastructure that present a sufficiently high risk to support creation of a separate mechanism. In addition, Cascade has not satisfied all of the guidelines adopted in Order No. 17-084.

**Q. Please describe Staff's analysis of the Company's proposal for the proposed SCRM.**

A. Staff evaluated the Company's proposal using the UM 1722 guidelines and also explored the relationship between the guidelines, the Company's annual safety plan, and the more detailed Distribution Integrity Management Program (DIMP) and Transmission Integrity Management Program (TIMP) plans prepared by the Company.

**Q. Regarding the UM 1722 guidelines, does the Company's request comply with guideline 1, which requires that the mechanism be**

[17] See *In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into Recovery of Safety Costs by Natural Gas Utilities*, Docket No. UM 1722, Order No. 17-084 (Mar 06, 2017).

**proposed in a general rate case or within three years of a final order in rate case?** [18]

A. Yes. The request to establish the SCRM is occurring in this general rate case.

**Q. Does the Company's request comply with guideline 2, which specifies that a SCRM will be limited to discrete safety related capital investments or other costs that are capitalized and that are identified at the time the SCRM is established?** [19]

A. No. Staff does not have sufficient information to evaluate the proposed projects after 2019. The guideline requires that the request "be limited to discrete safety-related capital investments or other costs that are capitalized and that are identifiable at the time the SCRM is established." This guideline raises two issues for each project: 1) Are the projects safety related, and 2) has the Company identified the costs?

1) Are the projects safety-related?

Staff recognizes that projects are built for multiple reasons besides safety. While a project appearing in the Company's safety plan or DIMP/TIMP plans provides some evidence they are safety related Staff must consider the relative weighting of other objectives such as operational considerations and capacity growth. The Company's testimony does not provide sufficient information to

[18] Guideline 1: "An SCRM may be established in a general rate case ("GRC") or within three years of a final order in a GRC."
[19] Guideline 2: "An SCRM will be limited to discrete safety related capital investments or other costs that are capitalized and that are identified at the time the SCRM is established. An LDC may request authorization from the Commission to modify an SCRM to include additional discrete safety related capital investments that otherwise meet these guidelines, and other parties are free to support or oppose such a request."

evaluate the drivers behind each project. Furthermore, the Company's response to a Staff DR indicates several of the proposed projects are "not specifically called out in DIMP".

2) Has the company identified the costs?

As noted above, the proposed projects for the 2020-2023 years are vaguely referred to in testimony as "$10-13 million per year" and in general terms regarding location. This level of detail is neither discrete nor identifiable. Notably, the Company's response to Staff DR No. 280 revises this project volume to be $6-8 million per year.

**Q. Does the Company's request comply with guideline 3 regarding a cost recovery cap?** [20]

A. No, the rate cap proposed by the Company is not the same as a cost recovery cap. The Company is proposing a cap of 2.5 percent annual increase in rates. The Company notes in testimony that the $11.4 million for 2018 projects would be equivalent to a 1.99 percent increase in rates if a similar amount of projects were approved in the SCRM for 2019. This implies a 2.5 percent increase would be approximately $14 million. Using a percentage increase effectively builds in an escalation factor each year. Staff recommends that, if the SCRM is approved, the Commission adopt a

[20] Guideline 3: "An SCRM shall have a cost recovery cap, which will be set at the time the SCRM is established. The cost recovery cap may be adjusted up or down by the Commission to reflect new safety related projects that may be included in the SCRM in later years, or the removal or modification of safety related projects included in the SCRM."

dollar limit rather than a limit based on a percentage increase in annual rates.

**Q. Does the Company's request comply with guideline 4, which requires that the mechanism have an earnings test?** [21]

A. Yes, the Company has provided an exhibit showing how the earnings test would be applied.[22] Staff believes the Company's proposed approach is generally reasonable and has no further concerns regarding this guideline if the SCRM were approved.

**Q. Does the Company's request comply with guideline 5, which imposes a limit on cost recovery related to annual amount of depreciation for the LDC's Oregon rate base?**[23]

A. Yes. The Company states that calculation of the limit will occur in the Company's annual filing.[24] Staff notes that this provision creates an economic incentive to increase the level of spending on projects not related to safety as that would directly affect recovery of costs under the mechanism. Staff recommends the Commission set a baseline spending level to be considered for the duration of the mechanism to remove this incentive.

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[21] Guideline 4: "SCRMs will be subject to an annual earnings test that will allow utility investments to be tracked into rates only where the recovery does not cause the utility to exceed its authorized Return on Equity."
[22] CNG/204, Parvinen/Page 3 of 3.
[23] Guideline 5 "An SCRM will only recover eligible costs on an annual basis to the extent the LDC's total annual capital investments in all plant exceeds the annual amount of depreciation for the LDC's Oregon rate base."
[24] CNGC/200, Parvinen/18.

Q. **Does the Company's request comply with guideline 6 regarding the duration of the SCRM?** [25]

A. Yes, the company is proposing an initial duration of five years. However, Staff does not believe there is sufficient information to support a cost-recovery mechanism that lasts five years. Staff recommends that, if the SCRM is approved, the Commission adopt a shorter initial duration of three years.

**Q. How is the DIMP plan relevant to the Company's request for a SCRM in this case?**

A. Cascade's 2018 safety plan filed only 10 days before this case indicates that Cascade's DIMP and TIMP plans are the cost benefit analysis for the proposed projects. The Company's DIMP plan is required for risk-assessment under federal Pipeline and Hazardous Materials Safety Administration (PHMSA) rules.[26] These regulations required natural gas distribution companies, such as Cascade, to establish a distribution integrity management program (DIMP) by August 2, 2011. A DIMP must include these elements, among others: 1) identification of existing and potential threats, 2) an evaluation and ranking of risks, 3) identification and implementation of measures to address risks, and 4) measurement of performance, monitoring program results and evaluating effectiveness.

[25] Guideline 6 "The duration of the SCRM will be specified at the time the SCRM is established. The duration may be modified if new safety-related projects are added to the SCRM in later years by the Commission."
[26] CFR 492 – Part 192 – Subpart P … Gas Distribution Integrity Management (IM). See also: https://primis.phmsa.dot.gov/dimp/.

The Company must consider existing and potential threats in eight categories in its DIMP, using sources outlined in the regulation: corrosion, natural forces, excavation damage, other outside force damage, material or welds, equipment failure, incorrect operations, and other concerns that could threaten the integrity of its pipeline. An operator must include in its written DIMP plan all measures it selected to reduce risk from failure on those portions of its gas distribution pipeline that met its criteria for needing a measure to address the risk identified through its risk evaluation process.

Once a company has a DIMP, it must evaluate the program at a period appropriate for the system, but at an interval not exceeding five years. The DIMP must be re-evaluated whenever new knowledge, new threats or other information would substantially alter the DIMP. PHMSA issues Advisory Bulletins that are relevant to DIMP when they advise of risks related to gas pipeline systems.[27]

**Q. Why is the timing difference between the DIMP update and the annual safety plan important?**

A. The Company is asking the Commission to approve the SCRM without review of the underlying cost benefit analysis. As noted above, the Company stated, "The DIMP and TIMP risk assessment models essentially act as the Company's cost benefit analyses for projects."[28] The Company also reported in

[27] Volume 77, Federal Register 17119 (March 23, 2012), available at: https://www.gpo.gov/fdsys/pkg/FR-2012-03-23/pdf/2012-7080.pdf.
[28] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Annual Natural Gas Safety Project Plan Supplemental Application*, Docket No. UM 1899, Page 10.

its 2018 safety plan filing that, "[w]henever the Company revises either its DIMP or TIMP, it files the updated version with Commission Safety Staff. Cascade anticipates filing a revised DIMP later in 2018."[29]

**Q. Do the 2018 projects associated with the SCRM also appear in the 2018 safety plan?**

A. Yes, along with planned O&M expenditures for safety initiatives.[30] The projects in the safety plan total $11.4 million, which agrees with the figure cited in the Company's testimony in support of the SCRM.[31]

**Q. The Company is requesting to establish a SCRM for five years. Are any of the projects for 2019 and subsequent years listed in the 2018 safety plan?**

A. No.

**Q. Are any of the proposed SCRM projects related to TIMP?**

A. At this time, no. Staff's copy of the TIMP is dated December 31, 2015, although the Company's filing in Docket No. UM 1899 states that an updated TIMP was provided to the Commission in April 2018.[32] The Company's testimony in this case does not clearly state that TIMP projects would be included although they are discussed in the safety plan.

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[29] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Annual Natural Gas Safety Project Plan Supplemental Application*, Docket No. UM 1899, Page 5.
[30] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Annual Natural Gas Safety Project Plan Supplemental Application*, Docket No. UM 1899, Page 13.
[31] CNGC/200, Parvinen/17.
[32] See *In the Matter of CASCADE NATURAL GAS CORPORATION, Annual Natural Gas Safety Project Plan Supplemental Application*, Docket No. UM 1899, Page 5.

**Q. Are the planned projects for 2019 provided in the Company's testimony?**

A. The Company refers to "Phase 8 through 12" of the Bend pipe replacement program and expanding its focus to other areas its system including Pendleton".[33] The specific projects proposed for 2019 are listed in CNG/204, Parvinen/Page 3 of 3.

**Q. Does Staff find the SCRM is not appropriate, even if it could meet the guidelines?**

A. Yes, Staff has significant concerns about the relationship of the proposed mechanism to the existing DIMP and TIMP process.

**Q. When was the most recent DIMP plan filed with the Commission's Safety, Reliability and Security Division?**

A. The plan update was dated August 5, 2016. However, most of the information in the plan document is circa 2012.

**Q. Does Staff have particular concerns after reviewing this document?**

The Company appears to be updating the distribution and transmission system data and analysis underlying the DIMP and TIMP plans and the proposed projects for 2018 and 2019. However, since updated written plans are not being produced and submitted to the Commission on a timely basis, Staff does not have the information necessary to review the proposed projects.

When reviewing the 2012 DIMP plan, Staff notes that corrosion and material concerns represent only 13 percent of the risk score for Oregon.

[33] CNGC/200, Parvinen/20.

Accordingly, Staff is questioning whether the Company is perhaps lumping together small sections of old pipe with a history of corrosion with larger portions that do not have that history, and proposing to replace large swaths of the system under the pretext of safety improvements.[34]

Pipeline replacement is only one aspect of the risk evaluation and ranking discussed in the DIMP and TIMP. Approval of the SCRM may elevate the priority of pipeline replacement and improvement projects relative to other risk mitigation and management actions as presented in those plans. Also, in Staff's view, safety cost mechanisms were originally conceived to facilitate faster cost recovery of federally mandated system improvements than would otherwise have occurred in general rate cases. There are currently no major new federal requirements scheduled to go into effect beyond the bare steel replacement program. Accordingly, this calls into question the appropriateness of creating a special rate recovery mechanism in absence of new mandates.

**Q. Does Staff recommend the Commission approve the Company's request to establish an SCRM?**

A. No. As discussed above, the Company is requesting a five-year mechanism but only discusses 2018 and 2019 projects in testimony. The 2018 safety plan filed only ten days before this case refers to the DIMP/TIMP plans as the cost benefit analysis for the proposed projects. The Company's responses to subsequent Staff data requests indicates the expected project volumes will be

[34] See *Distribution Integrity Management Program*, Appendix E - Risk Analysis, Table E3.2: Risk Score and Ranking by State.

approximately 40 percent less that the amounts listed in opening testimony and also that many of the proposed projects do not actually appear in the DIMP/TIMP plans. The DIMP/TIMP plans are essential for Commission to understand how the proposed projects fit into the Company's overall risk mitigation strategy and current federal safety requirements. Furthermore, Staff data requests and adjustments regarding 2018 projects indicate that even the costs presented in this case for near term projects are unreliable. Staff cannot recommend approval of the proposed SCRM mechanism under these circumstances.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UG 347
WITNESS: JOHN L. FOX

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 201

# Witness Qualifications Statement

# September 27, 2018

# WITNESS QUALIFICATION 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.

CASE: UG 347
WITNESS: JOHN L. FOX

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 202

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

**Request No. 122**

Date prepared: 7/3/18

Preparer: Becky Beach

Contact: Pamela Archer

Telephone: (509)-734-4591

122. Regarding Exhibit CNGC/203, Parvinen/1:

a. Please provide all work papers and other information underlying calculation of the following amounts:
   i. EDIT Plant Total System $41,264,063;
   ii. EDIT Non-Plant Total System $7,897,732; and
   iii. EDIT Plant 2018 Excess ARAM & Amortization $1,699,492.

b. For the three amounts in subpart a.i through a.iii, please provide a reconciliation and references to the information previously provided in the Company's responses to Staff's Standard Data Request (SDR) Nos. 114 through 118.

c. Based on Staff's review of the Company's response to SDR No. 116, the Total System EDIT figures in Exhibit CNGC/203, Parvinen/1 do not include the FAS 109 gross up. Please:
   i. Indicate whether or not this finding is correct; and
   ii. If this finding is correct, provide a revised calculation of Exhibit CNGC/203, Parvinen/1, with the gross up included.

d. Please explain the rationale underlying the Company's decision to amortize the EDIT Non-Plant amounts over 10 years.

e. Please explain why the plant allocator percentage is appropriate for determining the Oregon portion of EDIT Non-Plant.

f. Please provide a schedule showing the anticipated EDIT Plant ARAM reversals for the next five years after the test year including the FAS 109 gross up. If this information is unavailable at this time, consider this an ongoing request, and please provide a detailed explanation as to why the amount cannot be calculated at the time of the initial response, including a description of the relevant recordkeeping and computer software limitations.

**Response:**

# CASCADE NATURAL GAS CORPORATION
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c. Exhibit CNGC/203 is not grossed up. However, the gross-up in contained and shown in Exhibit CNGC/304, column (p), row 34. There is no need to revise Exhibit CNGC/203.

d. The reason for suggesting 10 years is three-fold.
   1. The average period for each item contained in the Non-Plant EDIT works out to approximately 10 years.
   2. For consistency each of the utilities within the MDU umbrella is requesting 10 years.
   3. Washington has accepted the 10-year amortization in its most recent rate case settlement (UG-170929).

e. There are two reasons for using the plant allocator.
   1. Consistency with the Plant EDIT. There is no one specific allocator that seemed to work for Non-Plant so the Plant allocator was used to keep the allocation simple.
   2. Washington approved the Plant allocator as reasonable in Docket UG-170929. So, to maintain consistency, the same allocator was used in the current rate case.

For items a – c, see attached spreadsheet.
For item f, see attached spreadsheet.

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
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**Request No. 133**

Date prepared: July 10, 2018

Preparer: Maryalice Peters

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 133**

Regarding Exhibit CNGC/305, Peters/1-3, where the Company represents 2018 plant additions for system-wide and for Oregon-allocated and situs projects, please provide, as of the date of generating the exhibit:

a. Identification of the funding projects associated with the three near-term projects listed in the 2018 IRP page 8-10;
b. Identification of funding projects for 2018 that would otherwise be recovered under the proposed Safety Cost Recovery Mechanism (SCRM) if they were to occur in a future year and the SCRM is approved as proposed;
c. Year to date transfers to plant by month by funding project for 2018 to date and projected transfers to plant by month by funding project for the remainder of 2018;
d. Actual or anticipated in-service date for each Oregon-allocated and situs project; if the Company finds an in-service date does not apply because the project is programmatic (ongoing) please explain the basis for this finding;
e. Actual annual capital expenditures of Oregon-allocated and situs projects for each plant account (e.g. 3761 – CNG Mains Steel = $x situs and/or $y Oregon-allocated) from 2013 through 2017.
f. Actual annual capital expenditures of Oregon-allocated and situs projects for each blanket funding project (e.g. FP-101170 – MAIN-GROWTH-OREGON = $x situs and/or $y Oregon-allocated) from 2013 through 2017.

**Response:**

a. Funding projects associated with the three near-terms projects listed in the IRP are as follow:

FP-316575 - Bend 6" HP Steel Reinforcement
FP-316407 - Bend 4" IP PE Reinforcement: Archie Briggs Rd
FP-316243 - Bend 4" IP PE Reinforcement: Hayes Ave

# CASCADE NATURAL GAS CORPORATION
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b. Identification of funding projects under the proposed SCRM:
See Parvinen Exhibit 204, page 3 of 3:
FP-200688 - 2006 Bend Pipe Replacement Phase 8
FP-200689 - 6" Bend HP Replacement Phase 2
FP-303142 - Pendleton Pipe Replacement Phase 2
FP-306997 - 4" Madras HP Replacement Phase 2
Funding project identification has not been established yet for Milton-Freewater Bare Steel Replacement.

c. See OPUC-133 Parts C&D.xlsx
d. See OPUC-133 Parts C&D.xlsx
e. See OPUC-133 Cap Ex Part E.xlsx
f. See OPUC-133 Cap Ex Part F.xlsx

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
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**Request No. 133 Revised**

Date prepared: July 10, 2018

Preparer: Maryalice Peters

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 133**

Regarding Exhibit CNGC/305, Peters/1-3, where the Company represents 2018 plant additions for system-wide and for Oregon-allocated and situs projects, please provide, as of the date of generating the exhibit:

a. Identification of the funding projects associated with the three near-term projects listed in the 2018 IRP page 8-10;
b. Identification of funding projects for 2018 that would otherwise be recovered under the proposed Safety Cost Recovery Mechanism (SCRM) if they were to occur in a future year and the SCRM is approved as proposed;
c. Year to date transfers to plant by month by funding project for 2018 to date and projected transfers to plant by month by funding project for the remainder of 2018;
d. Actual or anticipated in-service date for each Oregon-allocated and situs project; if the Company finds an in-service date does not apply because the project is programmatic (ongoing) please explain the basis for this finding;
e. Actual annual capital expenditures of Oregon-allocated and situs projects for each plant account (e.g. 3761 – CNG Mains Steel = $x situs and/or $y Oregon-allocated) from 2013 through 2017.
f. Actual annual capital expenditures of Oregon-allocated and situs projects for each blanket funding project (e.g. FP-101170 – MAIN-GROWTH-OREGON = $x situs and/or $y Oregon-allocated) from 2013 through 2017.

**Response:**

a. Funding projects associated with the three near-terms projects listed in the IRP are as follow:

FP-316575 - Bend 6" HP Steel Reinforcement
FP-316407 - Bend 4" IP PE Reinforcement: Archie Briggs Rd
FP-316243 - Bend 4" IP PE Reinforcement: Hayes Ave

# CASCADE NATURAL GAS CORPORATION
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b. Identification of funding projects under the proposed SCRM:
See Parvinen Exhibit 204, page 3 of 3:
FP-200688 - 2006 Bend Pipe Replacement Phase 8
FP-200689 - 6" Bend HP Replacement Phase 2
FP-303142 - Pendleton Pipe Replacement Phase 2
FP-306997 - 4" Madras HP Replacement Phase 2
Funding project identification has not been established yet for Milton-Freewater Bare Steel Replacement.

c. See OPUC-133 Revised Parts C D In Service Dates.xlsx
d. See OPUC-133 Revised Parts C D In Service Dates.xlsx
e. See OPUC-133 Cap Ex Part E.xlsx
f. See OPUC-133 Cap Ex Part F.xlsx

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
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**Request No. 134**

Date prepared: July 18, 2018

Preparer: Maryalice Peters

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 134**

Consistent with Commission Order 16-109 at page 14, issued in Docket UG 288, please provide the following with respect to each Oregon-allocated and situs project over $150,000, as listed in Exhibit CNGC/305, Peters/1-3:

a. Comprehensive cost-benefit analysis of whether and when investment should be built;
b. Evaluation of range of alternative build dates and the impact on reliability and customer rates;
c. Evidence on the likelihood of disruptions based on historical experience;
d. Evidence on the range of possible reliability incidents;
e. Evidence about projected loads and customers in the area; and
f. Consideration of alternatives, including use of interruptibility or increase demand-side measures to improve reliability and system resiliency.

**Response:**

See various OPUC-134 fund projects attachments.

# CASCADE NATURAL GAS CORPORATION
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**Request No. 134**

Date prepared: July 18, 2018

Preparer: Doug DiJulio

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 134**

Consistent with Commission Order 16-109 at page 14, issued in Docket UG 288, please provide the following with respect to each Oregon-allocated and situs project over $150,000, as listed in Exhibit CNGC/305, Peters/1-3:

a. Comprehensive cost-benefit analysis of whether and when investment should be built;
b. Evaluation of range of alternative build dates and the impact on reliability and customer rates;
c. Evidence on the likelihood of disruptions based on historical experience;
d. Evidence on the range of possible reliability incidents;
e. Evidence about projected loads and customers in the area; and
f. Consideration of alternatives, including use of interruptibility or increase demand-side measures to improve reliability and system resiliency.

**Response:**

FP-101480 - UG-Work Asset Management

Maximo is a work management system replacing fragmented operations systems into one centralized and integrated system. This includes replacing PIM, Construction Tracking, DOT Web App, project cost estimation software, paper processes, compliance tracking for leak survey and various other JIRA/Web based tracking tools.

Maximo will provide six primary benefits:

1. Align operations business processes across the field offices and enterprise.
2. Replace fragmented and unintegrated operations technology systems/processes with one unified work and asset management system – improving efficiency of implementation and support.

# CASCADE NATURAL GAS CORPORATION
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3. Reduce touch points and redundancy.
4. Gain enterprise-wide insight into asset tracking, construction, maintenance, compliance and costs. This includes tracking Operation's Key Performance Indicators (KPI's).
5. Drive consistent work flows across the enterprise; improving work product results.
6. Improve the user experience with consistent field data entry technology – lowers training needs, and limits confusion and errors.

Any potential savings generated will be from improved efficiencies that come from the elimination of touchpoints caused by paper processes and fragmented systems.

A 7-member team consisting of management from Field Operations and Information Technology was formed to conduct investigated research on existing Maximo installations at other Utility Companies. This team held site visits at 2 Utility Companies located in Washington and Oklahoma.

The site visits consisted of several sessions including product demo, project planning, project implementation, on-going maintenance requirements, organizational support structure, field operations, functions implemented/recommended, and lessons learned.

Several alternatives have been considered for Work and Asset Management including, Maximo, SSP Lifecycle Work (WFM), enhancing our current systems or maintaining the status quo. The merits of each alternative have been identified and reviewed.

The "Field Operations IT Planning committee" has recommended that a business case be developed and presented to executive management recommending the implementation of Maximo. It has been submitted and currently under review.

# Project Summary – Bend Phase 7 Section 1 Pipe Replacement, Bend District

Submitted by: Kathleen Chirgwin, P.E.
3/8/2017

*Background*

In 2012 Cascade started the Bend pipe replacement to replace 1930 pre-manufactured gas main in downtown Bend to improve system reliability. To date we have completed six years of replacement projects and this project is to start Phase 7. In 2018, Phase 7 will be completed in two sections. Phase 7 Section 1 is located on W 14th St and is part of a city improvement project schedule for summer construction. Phase 7 Section 2 will be completed after Phase Section 1 is installed this summer.

*Proposal*

Phase 7 Section 1 replacement statistics:

- Install 84 feet of 2 in PE
- Install 368 feet of 4 in PE
- Install 570 feet of 2 in Steel
- Install 1618 feet of 4 in Steel
- Tie-over 4 existing steel service lines
- Install 2 new PE service lines totaling 85 feet in length

Phase 6 in 2017 went through a remote bid show for Phase 6 Section 1 and 2 with the understanding that prices would be held for Phase 6 Section 3. NWMF and Brothers were the only two contractors to provide pricing on this project. NWMF was the lowest bidder and was selected as the contractor. NWMF has agreed to hold pricing from their 2017 bid pricing for this project.

*Timing*

Construction is planned to start March 15. Construction is planned to be completed by the mid-June of 2018 based on the city's relocation deadline.

*Costs/WO Setup:*

*Phase 7 Section 1 Main, Funding Project: 316697, WO: 253072 - $1,255,023.88*
*Phase 7 Section 1 Service, Funding Project: 316698, WO: 253073 - $30,665.08*

*Total Cost in PowerPlan for Phase 7 Sec 1 work orders: $ 1,285,866.96*

This project is in the 2018 budget under funding project 200688. New funding projects and WO have been setup for Bend Phase 7 Section 1 WO's and spending estimates have been updated in the funding projects.

*Benefits*

1. System Reliability- aging 1930 pre-manufactured gas pipe that Cascade purchased from the city of Bend is being replaced with a new PE system.

2. City relocate and opportunity to install pipe before the city rebuilds this road.

*Alternatives*

No alternatives can be identified. Given the age of the pipe it will need to be replaced in the near future. Completing this project will help eliminate costs involved with leak repair as well as upgrade an aging system and provide a safer gas distribution system.

*Project Team*

Project Manager/Engineer: Kathleen Chirgwin
District Operations Manager: Bill Walker
Project Coordinator: Brian Gainer
Regional Director: TBD

# Project Summary – Bend Pipe Replacement Phase 7 - Section 2

Submitted by: Ryan Privratsky
07/11/2018

*Background*

In 2012 Cascade started the Bend pipe replacement to replace 1930 pre-manufactured gas main in downtown Bend to improve safety and system reliability. To date Cascade has completed six years of replacement projects and this year will be Phase 7. Phase 7 will be completed in two sections. Phase 7 Section 1 was recently completed and was located on W 14th St. Phase 7 Section 2 will continue from the end of Section 1 and run south on W 14th St. to SW Commerce Ave. Project is being completed in conjunction with a City of Bend improvement project which is scheduled for construction beginning in August.

*Proposal*

Project consists of installing approximately 1,618' of 4" steel, 366' of 4" PE, 570' of 2" steel, and 84' of 2" PE.

*Timing*

Design of Phase 2 began in June 2018 and plans are currently being worked on. Construction is scheduled to begin later this summer in conjunction with the City of Bend project.

*Costs*

The 2018 budget includes $2,636,607 for Phase 7. Portion of this was used for Phase 7 Section 1, remaining will be used for Phase 7 Section 2.

*Benefits*

1. Opportunity to install pipe in conjuction with City of Bend project.
2. Safety and System Reliability - aging 1930 pre-manufactured gas pipe that Cascade purchased from the city of Bend is being replaced with a new steel and PE system.

*Alternatives*

No alternatives can be identified. Given the age of the pipe it will need to be replaced in the near future. Completing this project will help eliminate costs involved with leak repairs as well as upgrade an aging system and provide a safer gas distribution system.

*Project Team*

Project Manager/Engineer: Kathleen Chirgwin
District Operations Manager: Bill Walker
Project Coordinator: Brian Gainer
Regional Director: Don Moore

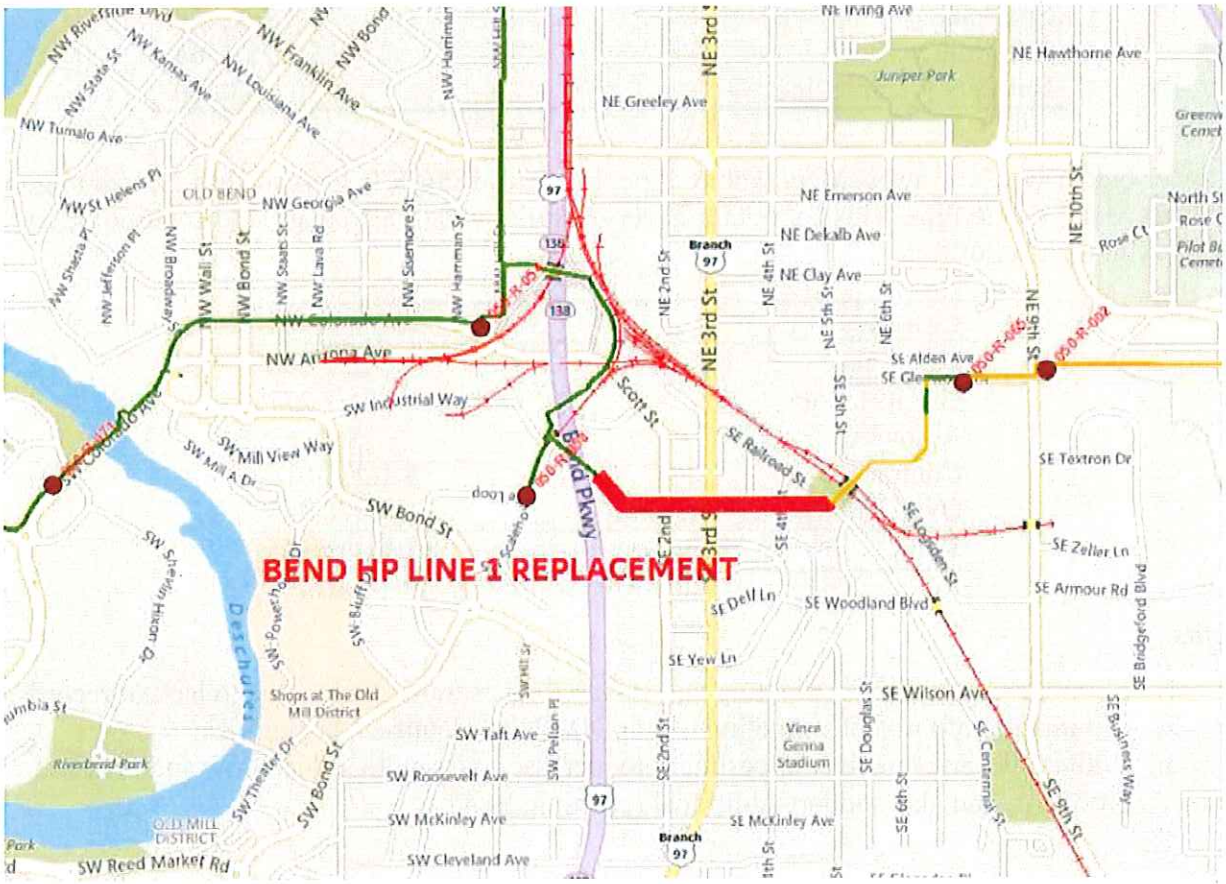
# Project Summary –Bend HP Line 1 Replacement – WO 253704

Submitted by: Chris Bolton
6/14/2018

*Background*

HP Line 1 in the Bend District starts at the Bend Gate and runs into the town of Bend. The existing line is 6" and was installed over 60 years ago. The MAOP of the line is 300 psi and the line usually operates about 250 psi. This portion of the pipeline is classified as transmission due to lack of documentation.

The project site starts in Jaycee Park and heads west on SE Miller Ave. The location is shown on the map below:




*Proposal*

This project consists of installing about 2,000 feet of 12" HP pipeline. Considering the location and the conditions, the majority of the project will be installed via open trench with one short bore.

*Timing*

Design for this project began in February 2018 and plans were completed in May 2018. A contractor pre-bid meeting was held on May 31st, 2018 and five potential bidders attended. The project is scheduled to begin in August 2018.

*Costs*

Engineering has prepared construction plans and bid documents and solicited bids from five bidders, four of which submitted bids. Results from the bid process are summarized below:

| BID SUMMARY | |
|---|---|
| **BIDDER** | **BID AMOUNT** |
| Northwest Metal Fab & Pipe, Inc. | $ 886,570 |
| Snelson | $ 2,222,418 |
| InfraSource | $ 1,252,363 |
| Brothers Pipeline, Inc. | $ 1,283,540 |

The lower bidder was Northwest Metal Fab & Pipe, Inc. with $886,570. Cascade has elected to go with Northwest Metal Fab & Pipe. This contractor is very familiar with the area, ground conditions, and working with the City of Bend:

| Category | Cost |
|---|---|
| Materials | $ 220,000 |
| CNGC labor | $ 57,277 |
| Resources | $ 4,263 |
| Contractors | $ 1,233,012 |
| Overhead | $ 278,980 |
| **Total** | **$ 1,793,532** |

*Benefits*

1. Elimination of pre-code pipeline that is classified as transmission due to lack of records.
2. Elimination of Pre-CNG pipeline which DIMP has identified as high risk.
3. While replacing this line, opportunity to increase line size to reduce flow and pressure problems, and also support additional growth in Bend.

*Alternatives*

We have insufficient records on this pipe. Combining this with its old age, replacement is the only reasonable solution.

*Responsible People*

District Contact: Cody Cox
Project Engineer: Chris Bolton
Project Foreman: TBD
Cascade Inspector: TBD

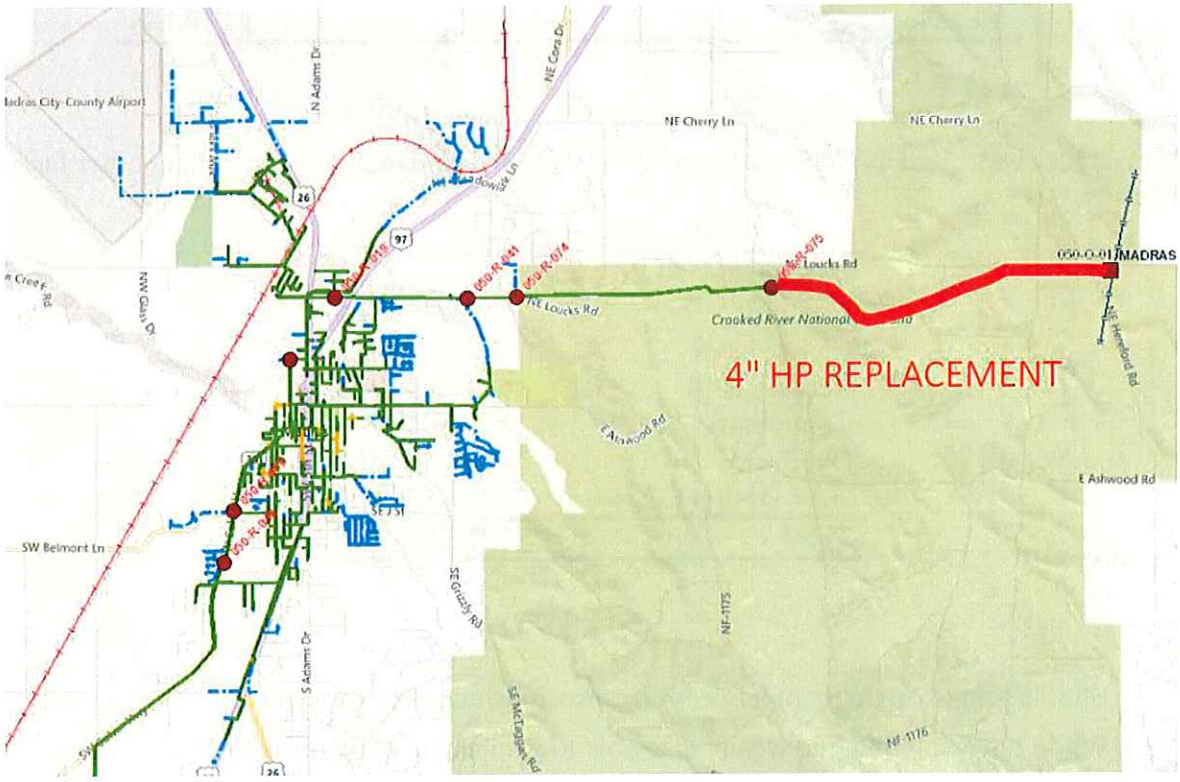
# Project Summary – 4" Madras HP Replacement

Submitted by: Chris Bolton
4/23/2018

*Background*

HP Line 2 in the Bend District starts at the Madras gate and runs into the town of Madras. The pipe that is currently in us is a 4" HP line that was installed in 1962. The MAOP of the line is 260 psi and the line usually operates about 250 psi. This pipeline also has documented leaks and corrosion concerns.

The project site stretches through the Crooked River National Grassland and is shown in the map below:




*Proposal*

This project consists of installing about 13,000 feet of 6" HP pipeline. Considering the location and the conditions, the majority of the project will be installed via open trench method.

*Timing*

Design for this project began in May 2017 and plans were completed in January 2018. A contractor pre-bid meeting was held on January 25th, 2018 and five potential bidders attended. The project is scheduled to begin in June 2018 based on the delays in the USFS permit process.

*Costs*

Engineering has prepared construction plans and bid documents and solicited bids from five bidders. Results from the bid process are summarized below:

| BID SUMMARY | |
|---|---|
| **BIDDER** | **BID AMOUNT** |
| Northwest Metal Fab & Pipe, Inc. | $ 1,084,900 |
| Snelson Companies, Inc. | $ 1,079,800 |
| Brothers Pipeline, Inc. | $ 1,036,945 |
| InfraSource | $ 975,771 |
| Michels | $ 730,236 |

The lower bidder was Michels Construction with $730,236. The overall cost including other factors is shown below:

| Category | Cost |
|---|---|
| Materials | $ 385,000 |
| CNGC labor | $ 26,205 |
| Resources | $ 34,543 |
| Contractors | $ 1,056,264 |
| Overhead | $ 492,580 |
| 2017 Design Costs | $ 500,000 |
| **Total** | **$ 2,494,592** |

*Benefits*

1. Elimination of an aging pipeline with corrosion and leak history.
2. While replacing this line we are also able to gain capacity by upsizing.
3. Replace pre-code pipeline with insufficent construction records.

*Alternatives*

We have insufficient records on this pipe. Combining this with its old age, replacement is the only reasonable solution.

*Responsible People*

District Contact: Brian Gainer
Project Engineer: Chris Bolton
Project Foreman: TBD
Cascade Inspector: TBD

**100G ERT Upgrade Project**

A cost-benefit analysis was completed before the initial installation of the 40G ERT AMR implementation in 2002. It was determined that there was a positive cost benefit using the 40G AMR technology in place of manually reading meters. The 40G ERT's are now at end of life and are being replaced by 100G AMR technology. The study performed in 2002 is still relevant therefore was used as the cost-benefit analysis for this project. There has been an increase in 40G AMR failures due to end of life components. The 40G component failures have increased operating costs and decreased reliability. Continuing to replace the 40G ERT's as they fail would result in an inefficient and cost prohibitive means to reading customer meters. A study published by the ERT manufacturer(Itron) indicates the ERT failures will increase drastically starting the 16$^{th}$ year in service. Cascade Natural Gas findings align with this study. The 40G ERT to 100G ERT change can be performed without disrupting service. A disruption to service could occur if the ERT couldn't be replaced and the complete meter/ERT assembly was replaced. The 40G ERT to 100G ERT project will increase reliability and provide a cost savings for the customer.

# Umatilla 2-inch Reinforcement FP-306989

Submitted by: Clayton Moreau
8/15/17

*Background*

The system between the Umatilla River and I-82 is single feed.

*Proposal*

New regulator station with inlet and outlet valves and 5000' of 4" HP steel. Allows for maintenance and repairs of the systemin the area.

*Timing*

Construction will take place during 2018.

*Costs*

Costs are based on recent completed projects.

*Alternatives*

None

*Responsible People*

Project Manager: Clayton Moreau
District Lead: Denny Whitsett
Project Foreman: TBD

# Project Summary – Pendleton Pipe Replacement Phase 2

Submitted by: Ryan Privratsky
07/11/2018

*Background*

The city of Pendleton, OR has a large portion of its distribution system which is made up of older steel with corrosion and leak history. The current MAOP of the system is 40 psi and it usually operates at about 35 psi. The distribution system to be replaced is mostly FISH pipeline installed approximately 50 to 60 years ago. This will be the second phase of the Pendleton Pipe Replacement project.

*Proposal*

Project consists of installing approximately 1,560' of 8" steel mainline and 1,030' of 4" steel mainline.

*Timing*

Design of Phase 2 began in January 2018 and plans are currently being worked on. A contractor pre-bid meeting is planned for later this summer with construction to begin possibly later this summer or early fall, and to be completed by the end of 2018.

*Costs*

The 2018 budget includes $2,142,626 for Phase 2.

*Benefits*

1. Elimination of FISH pipe with higher corrosion risk and known leak history.
2. Project will replace pipe with a higher risk as identified in CNGC's Distribution Integrity Management Program (DIMP).
3. Replacement of three cased crossings.

*Alternatives*

No alternatives can be identified. Given the age of the pipe it will need to be replaced in the near future. Completing this project will help eliminate costs involved with leak repairs as well as upgrade an aging system and provide a safer gas distribution system.

*Responsible People*

Project Manager: Clayton Moreau
District Manager: Denny Whitsett
Project Coordinator: TBD
Project Foreman: TBD

# Athena 2" Bridge Crossing FP-316430

Submitted by: Thomas Henderson
7/13/2018

*Background* -
Pipe is poorly coated and extremely difficult to inspect along the bridge crossing.

*Proposal* -
Replace the line via horizontal directional drilling (HDD).

*Timing* -
Construction will take place during 2018.

*Costs* -
Costs are based on recent completed projects.

*Alternatives* –
Keep pipe suspended on bridge.

*Responsible People* –
Project Manager: Ryan Privratsky
District Lead: Denny Whitsett
Project Foreman: TBD

# CASCADE NATURAL GAS CORPORATION
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**Request No. 265**

Date prepared: August 22, 2018

Preparer: Thomas Henderson, Ryan Privratsky, Renie Sorensen, Brian Robertson, & Doug DiJulio

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 265**

Regarding the Company's response to Staff data request 134, please provide the following:

a. For each pipeline project included in the Company's response, the specific date the project will be placed into service, providing utility service to customers.
b. For each pipeline project included in the Company's response, state whether the project includes an increase in capacity. For each project that includes an increase in capacity, please:
    i. Describe in detail the increased capacity in terms of pipe size, operating pressure, and gas delivery volumes.
    ii. Specifically identify the existing and future expected demand the increased capacity will fulfill, including but not limited to information by year, number of customers, customer location, and delivery volumes.
    iii. Provide a detailed explanation as to why the additional capacity is necessary in 2018 rather than in a future year.
    iv. Provide all studies, analysis, modeling, or other documentation supporting the increased demand projections.
    v. Provide specific references to page numbers in the current IRP, previous IRP, or any other commission filing discussing the project.
c. Regarding the project referenced as "FP-101480 UG-Work Asset Management",
    i. State whether the Maximo system will be completed and placed into service by December 31, 2018. If not, provide the estimated total cost of the project and date when the system will be placed into service.

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ii. Provide copies of any requests for proposals and any other procurement documents issued to or received from bidders related to the project.
iii. Provide a copy of the business case referred to in the Company's response to Staff data request 134.
iv. State if any cloud based (software as a service) options were considered and identify the vendor, costs, and pros and cons compared to the Maximo system.
v. Please describe what software is being used by other MDU operating units for similar functions, if they are using Maximo, when was Maximo implemented, and what was the final cost?

**Response:**

FP-316697

a. Project was in-service on 5/29/2018.
b. Project didn't increase capacity.

FP-200688

a. Estimated in-service date is 9/18/2018.
b. Project doesn't increase capacity.

FP-200689

a. Anticipated in-service date is 9/21/2018.
b. Yes, project increases capacity.
    i. CNGC is replacing existing 6" steel with 12" steel. The operating pressure will remain the same. The city of Bend has been experiencing immense growth and this is creating a constraint to CNGC's system in Bend. Both gate stations in Bend feed into the HP system and join up to feed the northwest Bend Area. The line that is being replaced has been experiencing these combined flows and needs to be upsized.
    ii. The northwest area of Bend has been growing as fast as any other area in the city of Bend. The increased capacity will help with our winter demand in the area. CNGC has used a cold weather action plan to supplement our system occasionally in the winter. This project, with projects in the near future should help lessen the need for the Cold Weather Action Plan. Exact flow volumes and customers counts are ever changing, but CNGC has seen a steady growth overall.
    iii. The need for the Cold Weather Action Plan indicates the increase in capacity is needed to improve system reliability year-round. The pipeline

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also needs to be replaced from an integrity standpoint, so it makes sense to also increase capacity at this time.

iv. CNGC has growth data from IRP along with our modeling software to simulate our current situation on this HP line. The replacement was first modeled with 8" pipe but based on the growth and flow it is worth it to upsize it to 12" while replacing it now.

v. 2018 Annual Oregon Safety Plan, page 13.

FP-303142

a. Estimated in-service date is by 11/30/2018. Construction contractor or construction schedule hasn't been established yet.
b. Project doesn't increase capacity.

FP-306997

a. Anticipated in-service date is 9/14/2018.
b. Yes, project increases capacity.
   i. CNGC is replacing existing 4" steel with 6" steel. The operating pressure will remain the same. During peak conditions in Madras, the existing 4" line is currently near full capacity.
   ii. No future demands have been identified at this time.
   iii. Project is mainly being driven by integrity reasons. With the line currently being operated near full capacity, during peak conditions, CNGC decided to add additional capacity at this time. The cost difference of installing a 6" line versus a 4" line now is minimal compared to replacing the existing line with another 4" line and then having to do additional reinforcements at a later date when additional capacity is needed.
   iv. Modeling software was used to determine the increase in capacity versus the costs of installing different sizes other than 4". Modeling showed installing a 6" would meet current and possible future needs.
   v. 2018 Annual Oregon Safety Plan, page 13.

FP-306989

a. Estimated completion date of 12-7-2018.
b. Yes, however the purpose of the project is to provide 2nd feed to the distribution system allowing us to take the existing feed out of service to preform needed maintenance activities in the coming years.
   v. 2018 OR IRP Action Plan page 10-5 and costs are provided in Appendix I – Distribution System Planning.

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FP-316430

a. Estimated in-service date is 11/30/2018.
b. Project does not increase capacity.

FP-308022

Although FP-308022 was responded to in Staff Data Request 134, it is neither a pipeline project nor is it related to the Work Asset Management project. Thus, it has not been addressed in this data request.

c. Regarding the project referenced as "FP-101480 UG-Work Asset Management",

i. State whether the Maximo system will be completed and placed into service by December 31, 2018. If not, provide the estimated total cost of the project and date when the system will be placed into service.
   - The Maximo system will not be completed or placed into service by December 31, 2018.
   - The Rough Order Magnitude (ROM) cost estimate to implement Maximo over a 5-year span across the 3-major utility brands is approximately $31M.

ii. Provide copies of any requests for proposals and any other procurement documents issued to or received from bidders related to the project.
   - As of this date we have not solicited any RFP's to vendors or contractors to support the implementation of Maximo.

iii. Provide a copy of the business case referred to in the Company's response to Staff data request 134.
   - The business case document has been included as OPUC-265 Confidential Maximo Business Case.pdf.

iv. State if any cloud based (software as a service) options were considered and identify the vendor, costs, and pros and cons compared to the Maximo system.
   - We will not be implementing the Maximo system on-prem. Our intention is to implement Maximo as a cloud based (software-as-a-service) hosted solution.

v. Please describe what software is being used by other MDU operating units for similar functions, if they are using Maximo, when was Maximo implemented, and what was the final cost?
   - Maximo has not been implemented within the other MDU operating units. Similar functions are currently being

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achieved through the usage of manual paper-based processes, in-house developed applications, 3rd party on-prem systems and hosted solutions. These systems either process independent of each other or exchange data via manual data entry, a direct interface or through an in-house maintained middleware application.

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**Request No. 266**

Date prepared: August 16, 2018

Preparer: Ryan Privratsky

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 266**

Regarding the projects referred to as "FP-316697" and "FP-200688" in the Company's response to Staff data request 134, specifically Bend Pipe Replacement Phase 7, please explain why the combined cost of these projects in the Company's filed rate case is $3.033 million compared to the $2.6 million cost in the Company's capital budget filed on May 21, 2018 in Docket UM 1899.

**Response:**

Difference is due to 2018 anticipated costs for FP-306997, 4" Madras HP Replacement, coming in lower than what was budgeted for 2018. Difference between the 2018 Anticipated Costs and 2018 Budgeted Costs for the Madras project were shifted to the 2018 Bend Pipe Replacement project (FP-316697 and FP-200688). Funds were shifted due to anticipating the need for additional funds to replace Phase 7 pipe in 2018 in conjunction with City of Bend improvement projects.

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**Request No. 267**

Date prepared: August 23, 2018

Preparer: Brett Hudson,

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 267**

Regarding the projects referred to as "FP-200688", "FP-303142", "FP-306989", and "FP-308022" in the Company's response to Staff data request 134, please provide specific information about the bidding process for construction of these projects, including but not limited to the timelines, criteria considered, number of bidders, prices, and winning bid.

**Response:**

**Bidding Process for Pipeline Projects:**

- Complete project design.
- Create specific project bid items based on specific items required based on project design.
- Schedule bid meeting with contractors to meet onsite to review project. Provide opportunity to go over the project and allow the contractor to ask any questions pertaining to the project. Typically, five pipeline contractors are invited to the bid meeting.
- Hold bid meeting with contractors.
- Allow time (typically 1-2 weeks) for contractor to submit bids and ask any follow-up questions.
- Contractor submits bid by specified bid due date.
- Company reviews bids and any bid submittals. Evaluate the following:
    - Project Costs
    - Contractors understanding of the project scope.
    - Safety
    - Previous experience completing similar work.

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- Project Schedule. Does contractor schedule meet in-service date requirements?
- Project supervision

**FP-200688** - The project bid meeting was held on August 7, 2018 and bids were due on August 14, 2018. Five contractors were invited to bid, but only two contractors submitted bids. Michels was awarded the work due to being the lowest bidder and their ability to meet the City of Bend construction schedule.

**FP-303142** - The project is estimated to go to bid in September. CNGC will invite about five contractors to participate.

**FP-306989 -** The project is estimated to go to bid 10-3-2018. CNGC will invite about five contractors to participate. We look at several factors in selecting the winning bid including but not limited to, cost, construction supervisor experience, contractor's ability to complete project within timeline, subcontractors they are using, experience with similar projects.

**FP-308022**- Bids were collected from Itron and Southern Cross in late 2017 to early 2018. The main criteria for the bidding selection was price and past work performed. Itron bid 6.9 million to perform the work. Southern Cross bid 5.3 million to perform the work. Southern Cross performed the field work for our sister company Intermountain Gas Company. The winning bid went to Southern Cross.

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**Request No. 280**

Date prepared: August 28, 2018

Preparer: Ryan Privratsky

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 280**

Please identify the specific projects that comprise the $10-13 million per year SCRM project costs (CNGC/200, Parvinen/17) and cross reference to the most recent DIMP and/or TIMP plan including year(s) and page number(s).

a. Please provide this information for all future years available but, at a minimum, for each year of the initial five year proposed life of the mechanism.

**Response:**

The current five-year plan for Oregon is projected to be between $6 - $8 million per year compared to the $10 - $13 million per year provided in the SCRM project costs (CNGC/200, Parvinen/17). Yearly estimated project costs include the following for 2019-2023:

| 2019 | 2020 | 2021 | 2022 | 2023 |
|---|---|---|---|---|
| $7.5 m | $7.4 | $6.6 | $7.1 | $7.3 |

The projects for 2019 - 2023 include mostly similar projects that have been completed or are in progress for 2018, projects include:

- Bend Pipe Replacement Phases 8 – 12
  - See DIMP Model Output Map
  - Identified as an Accelerated Action in Appendix F of DIMP (3/24/2017).

- 4" Madras HP Replacement Phases 2 – 3

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- See DIMP Model Output Map
- Identified by SME, Bill Walker, on 6/15/2016, see Subject Matter Expert Interview/Input Form. History of seam leaks, shorted casings, poor backfill.

- 6" Bend HP Replacement Phases 2 – 6
  - See DIMP Model Output Map
  - Identified by SME Bill Walker on 6/15/2016, see Subject Matter Expert Interview/Input Form. History of shallow pipe.
- Baker City Pipe Replacement Phases 1 – 3
  - See DIMP Model Output Map
  - Pre-CNG pipe, not specifically called out in DIMP. Pre-CNG has increased corrosion threat due to age of install and no, or inadequate, cathodic projection for a portion of its operating history, and history of being poorly coated. See DIMP Appendix D page 4 (3/31/2016).
- Bridge Crossing Replacements in Baker City
  - Not specifically called out in DIMP. Increased atmospheric corrosion risk (Appendix D, Page 3). Projects were identified by District and SME's to address pipe crossing bridges that are poorly coated and difficult to inspect. Project will replace exposed bridge crossings with buried directionally drilled crossings.
- Bridge Crossing Replacements in Milton-Freewater
  - Not specifically called out in DIMP. Increased atmospheric corrosion risk (Appendix D, Page 3). Project was identified by District and SME's to address pipe crossing bridge that is poorly coated and is difficult to inspect. Project will replace exposed bridge crossing with a buried directionally drilled crossing.

CASE: UG 347
WITNESS: BRIAN FJELDHEIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 300

# Opening Testimony

# September 27, 2018

**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, 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/301.

**Q. What is the purpose of your testimony?**

A. I am addressing certain non-labor expenses for distribution operations and maintenance (O&M), administrative and general (A&G), and the Company's rate case.

**Q. Did you prepare any other exhibits for this docket?**

A. No.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

**ISSUE 1. TRANSMISSION AND DISTRIBUTION - OPERATIONS & MAINTENANCE EXPENSE (NON LABOR) WITH ESCALATION**

**Q. Please describe the expense included in this issue.**

A. The Company uses 78 discrete internal object codes to book a range of operating and maintenance (O&M) expenses. O&M expenses for Distribution activities are recorded in FERC accounts 870-894 and 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 24.96 percent.[1]

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

A. The Company includes test year expense of $3,195,037 for non-labor Distribution O&M. Cascade arrived at this amount using 2017 Distribution non labor expenditures (FERC accounts 870-894) for the 2017 base year and escalating these expenses using the March 2018 CPI-U rate of 1.7 percent.[2] 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

[1] CNGC/301-306, Peters Workpapers/Excel worksheet State Allocation Formulas 2017 (cell C17).
[2] CNGC/301-306, Peters Workpapers/Excel worksheet Inflation Factors (cells C18 and C19).

maintenance supervision, mains and compressor station maintenance, measuring and regulating station equipment maintenance, and maintenance of meters and other operating equipment. Within FERC accounts 870-894, the Company's workpapers indicate that it is requesting non-labor Distribution escalation of $53,408.[3] The Company did not indicate any normalizing adjustments in their 2017 Distribution expenses.

**Q. Please explain the Staff analysis of these costs.**

A. Staff has typically reviewed the reasonableness of certain categories of Distribution expense by comparing the utility's test year expense to different benchmarks. Staff evaluated the test year by first removing disallowed or one-time expenses from the base year and then escalated the normalized base year using the All Urban Consumer Price Index (CPI-U). The Commission's use of the CPI-U as the preferred escalation factor is well supported.

**Q. Please provide the CPI-U used in Staff's analysis.**

A. Staff relied upon the Oregon Department of Administrative Services (DAS) Office of Economic Analysis June 2018 Oregon Economic and Revenue Forecast for the 2018 projected CPI-U (see below).[4]

CPI – Urban Consumers (June, 2018),[5]

1982-84 = 100

[3] CNGC/301-306, Peters Workpapers.
[4] Oregon Department of Administrative Services – Office of Economic Analysis, Revenue Forecast, which can be found at https://www.oregon.gov/das/OEA/Pages/Index.aspx.
[5] DAS Office of Economic Analysis subsequently issued the September 2018 Oregon Economic and Revenue Forecast.

| U.S. | 2016 | 2017 | 2018 |
|---|---|---|---|
| | 240.0 | 245.1 | 250.8 |
| % change | 1.3 | 2.1 | 2.3 |

**Q. Please describe Staff's analysis of the Company's proposal for Distribution O&M escalation.**

A. The Company used the method described above to determine its test year expense for the categories of Distribution reviewed in this testimony. Accordingly, Staff did an independent review of the Company's expenses, the normalizing adjustments to the base year, and the escalation to establish the test year. Staff utilized the Company's revised responses to Standard Data Request (SDR) Nos. 57 and 58. SDR Nos. 57 and 58 require the Company to provide information for all non-labor costs recorded in all FERC accounts for the base year. Staff suppressed data entries described as "actual burden" and "cross charge", as these define non-salary labor expenses and the apportionment of parent or affiliated company expenses to the Company, respectively.

Of the 78 expense object codes used within the Company's accounting system, Staff reviewed 30 expense object codes for possible adjustment to Company's base year Distribution O&M expenses. Staff segregated financial transaction data provided in response to SDR No. 57 by individual object code and then reviewed transaction memo descriptions and associated dollar amounts for possible outlier data subject to adjustment in the base year.

Company object codes reviewed by Staff:

| OBJ | Object Description |
|---|---|
| 5232 | Retired Director Fees and Expenses |
| 5234 | Director's Deferred Stock Comp |
| 5292 | Custodial Service & Supplies |
| 5293 | Collection Agency Fees |
| 5300 | Materials |
| 5400 | Company Vehicles & Work Equipment |
| 5422 | Rental Work Equipment |
| 5610 | Telephone |
| 5611 | Cell Phone |
| 5612 | Circuit Charges |
| 5620 | Multifunction Printer |
| 5630 | Office Supplies |
| 5640 | Utilities |
| 5651 | Postage |
| 5652 | Express Mail |
| 5661 | Rental of office equipment |
| 5812 | College Tuition and books |
| 5815 | Utility Discounts |
| 5820 | Moving Expenses |
| 5853 | Safety Training Materials & Expenses |
| 5891 | Uniforms |
| 5911 | Software Maintenance |
| 5913 | Permits & Filing Fees |
| 5914 | Bank Service Fees |
| 5931 | Rent |
| 5932 | Annual Easements |
| 5934 | Computer Rental |
| 5941 | Reimbursements |
| 5950 | Freight |
| 5982 | Reference Material |

Upon completing the review of base year transactions, Staff did not find any substantial transactions warranting adjustment.

Staff then reviewed the Company's proposed escalation calculation for base year Distribution expenses. In the Company's escalation calculation, Staff noted an immaterial discrepancy in the base year Oregon expenditure

allocation. The Company used an Oregon allocation factor of 25.15 percent and should have used 24.96 percent.[6] The Company escalated their base Distribution expenses using the March 2018 CPI-U of 1.7 percent.[7] The use of the CPI-U is in line with Commission practice and no adjustment was made to the Company's proposed escalation.

**Q. Does Staff propose an adjustment to the proposed 2018 test year?**

A. Upon reviewing 2017 base year transactions for possible outlier data, no significant transactions were noted. Upon reviewing the Company's use of the March 2018 CPI-U to escalate base year expenses, the Company's calculation appears to be in line with the Commission's practice of using the CPI-U.[8] Based on the lack of outlier transactions and the Company's use of CPI-U to escalate base year expenses, an adjustment to the Company's proposed test year O&M does not appear warranted.

**Q. What is Staff's recommendation regarding Distribution expense for the 2018 test year?**

A. For the assigned components of Distribution addressed in this testimony, Staff recommends no adjustment be made to the Company's proposed 2018 test year expense for escalation. As discussed above, the Company applied a

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[6] Company's response to Staff DR Nos. 173 and 174 were inconsistent. Response to Staff DR No. 173 shows Oregon's 2017 apportionment factor of 25.15 percent. Response to Staff DR No. 174 shows Oregon's 2017 apportionment factor of 24.96 percent. The same error occurs in CNGC/301-306, Peters Workpapers/ Excel workbook Inflation Factors (cells C18 and C19).

[7] The March 2018 CPI-U was confirmed via the Oregon Department of Administrative Services (DAS) – Office of Economic Analysis March 2018 Economic Forecast, Appendix A, page 43.

[8] See e.g., Orders 99-697 and 09-020 (basing test year expense on a three-year average of expenditures, including the base year, which is then escalated using the CPI-U; and Order 01-787 (test year expense based on two-year expense average that is then escalated using the CPI-U for the test year).

1.7 percent escalation rate to all 2017 operations and maintenance non-labor expenditures (FERC accounts 870 - 894). The Company did not indicate any normalizing adjustments in their 2017 Distribution expenses. Staff analysis of assigned Company Distribution expenses did not reveal any outlier or material one time transactions in the base year subject to disallowance or adjustment. The Company's use of the March 2018 CPI-U to escalate base year costs appears reasonable.

Please note that other members of Staff are reviewing additional components of Distribution and that a separate adjustment(s) to Distribution may be forthcoming.

**ISSUE 2. ADMINISTRATIVE AND GENERAL EXPENSE (NON LABOR) WITH ESCALATION**

**Q. Please describe the expense included in this issue.**

A. The Company uses 78 discrete internal object codes to book a range of administrative and general (A&G) expenses. A&G expenses are recorded in FERC accounts 921 – 922, 928, 930 and 931 and 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 24.96 percent.[9]

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

A. The Company used 2017 A&G non labor expenditures (FERC accounts 921 – 922, 928, 930 and 931) for the base year and escalated these expenses using the March 2018 CPI-U rate of 1.7 percent.[10] Multiple Staff reviewed separate components of A&G expenses. For A&G, the Company's workpapers indicate it is requesting non labor A&G escalation of $50,923.[11] The Company adjusted A&G expenses by removing membership fees (50 percent), officer incentive compensation, and various miscellaneous

[9] UG 347 Exhibit 301-306 Peters Workpapers Excel.xlsx, worksheet State Allocation Formulas 2017 (cell C17).
[10] UG 347 Exhibit 301-306 Peters Workpapers Excel.xlsx, worksheet Inflation Factors (cells C18 and C19).
[11] CNGC/304, Peters/1 at 16, Column (f).

expenses that are typically disallowed by the Commission, resulting in a reduction of $348,342 to A&G expenses in the 2017 base year.

**Q. Please explain the Staff analysis.**

A. As with the Distribution expenses, Staff did an independent review of the base year expenses, normalizing adjustments, and escalation using the same CPI-U relied on to escalate Distribution expenses. Staff utilized the Company's revised responses to SDR Nos. 57 and 58 for information regarding Cascade's expense during the base year. Company object codes reviewed are the same as reviewed for Distribution expense. Upon completing the review of base year transactions, Staff did not find any substantial transactions warranting adjustment.

Staff then reviewed the Company's proposed escalation calculation for base year A&G expenses. In the Company's escalation calculation, Staff noted a discrepancy in the base year Oregon expenditure allocation. The Company used an Oregon allocation factor of 25.15 percent and should have used 24.96 percent.[12] However, the result was immaterial. The Company escalated their base A&G expenses using the March 2018 CPI-U of 1.7 percent.[13] The use of the CPI-U is in line with Commission practice and no adjustment was made to the Company's proposed escalation.

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[12] Company's response to Staff DR Nos. 173 and 174 were inconsistent. Response to Staff DR No. 173 shows Oregon's 2017 apportionment factor of 25.15 percent. Response to Staff DR No. 174 shows Oregon's 2017 apportionment factor of 24.96 percent. The same error occurs in CNGC/301-306, Peters Workpapers/Excel workbook Inflation Factors (cells C18 and C19).

[13] Company's response to Staff DR Nos. 173 and 174 were inconsistent. Response to Staff DR No. 73 shows Oregon's 2017 apportionment factor of 25.15 percent. Response to Staff DR No. 174 shows Oregon's 2017 apportionment factor of 24.96 percent. The same error occurs in CNGC/301-306,Peters Workpapers/Excel workbook Inflation Factors (cells C18 and C19).

**Q. Does Staff propose an adjustment to the proposed 2018 test year?**

A. Upon reviewing 2017 base year transactions for possible outlier data, no significant transactions were noted. Upon reviewing the Company's use of the March 2018 CPI-U to escalate base year expenses, the Company's calculation appears to be in line with the Commission's practice of using the CPI-U. Based on the lack of outlier transactions and the Company's use of the projected March 2018 CPI-U to escalate base year expenses, an adjustment to the Company's proposed test year A&G does not appear warranted.

**Q. What is Staff's recommendation regarding Administrative and General Expenses for the 2018 test year?**

A. For the assigned A&G expenses, Staff recommends making no adjustment to the Company's proposed 2018 test year non-labor A&G expenses totaling $3,046,411. The Company applied a 1.7 percent escalation rate to all 2017 A&G non-labor expenses (FERC accounts 921 – 922, 928, 930 and 931). The Company indicated several normalizing adjustments to their aggregate 2017 A&G expenses.[14] However, in the portions of A&G expenses reviewed in this testimony, the Company did not make a normalizing adjustment. Staff analysis of assigned A&G expenses did not reveal any outlier or material one time transactions in the base year subject to disallowance or adjustment. The Company's use of the March 2018 CPI-U to escalate base year costs appears reasonable. Please note that other members of Staff are reviewing additional

[14] CNGC/304, Peters/1, line 16.

components of A&G and that a separate adjustment(s) to A&G may be forthcoming.

## ISSUE 3. UG 347 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 uses outside contractors to assist in their rate case filings. 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 filed proposal for this issue.**

A. The Company estimated total costs for outside contractors used on the rate case are $300,000. The Company proposes to use the equivalent of a three year amortization, and includes expense in the 2018 test year to accomplish this. Using the three year amortization, the Company request for rate case costs in the 2018 test year is $100,000.

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

A. The Staff's historical treatment of rate case costs is to review these costs for reasonableness. Rate case costs that are deemed reasonable are then treated as if they are being amortized over a multi-year period, typically three years. This methodology was used in the Company's prior rate case (UG 305).[15]

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

[15] UG 305 Staff/106, Gardner /4.

A. Staff analyzed Company's Exhibits 301-306 and Peters Excel worksheet "Rate Case Costs."[16] The Company incurred only modest contracted rate case expenses of $10,330 in the 2017 base year, due to the majority of rate case work being conducted in the 2018 test year. As a result, the Company proposes an adjustment to increase test year rate case expense by $89,670.

In the previous rate case, Staff treated rate case costs in the test year as if they were amortized over a three year period. In UG 305, the amortized rate case expense was $95,724 for the test year. Staff has no concerns with the Company's methodology in calculating current rate case costs.

**Q. Does Staff propose an adjustment to the proposed 2018 test year?**

A. Upon reviewing the Company's request of $100,000 for rate case expenses, an adjustment to rate case expense for the test year does not appear warranted. The Company's proposed amortized rate case expense of $100,000 is generally in line with previous rate case expenses.[17]

**Q. What is Staff's recommendation regarding rate case expense for the 2018 test year?**

A. Staff recommends making no adjustment to the Company's proposed rate case expenses totaling $100,000 for the test year.

**Q. Does this conclude your opening testimony?**

A. Yes.

[16] Additional details provided in CNGC /304, Peters /1, Column (r).
[17] UG 305 test year 2016 amortized rate case expense = $95,724.

CASE: UG 347
WITNESS: BRIAN FJELDHEIM

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 301

# Witness Qualifications Statement

# September 27, 2018

**WITNESS QUALIFICATION STATEMENT**

NAME: Brian Fjeldheim

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Financial Analyst
Energy Rates, Finance and Planning 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 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 insurers with annual revenues of $1.4 billion and assets of $1.1 billion.

CASE: UG 347
WITNESS: SCOTT GIBBENS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 400

# Opening Testimony

# September 27, 2018

**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/401.

**Q. What is the purpose of your testimony?**

A. In this testimony, I will discuss Staff's position on Cascade's proposed revenues and insurance expense for the test year. I will also discuss Cascade's current decoupling mechanism and recommended improvements.

**Q. Did you prepare an exhibit for this docket?**

A. Yes. I prepared Exhibits Staff/402. This is Cascade's design document on its current load forecasting methodology.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1. INSURANCE

**Q. Please provide a background for this issue.**

A. Staff reviewed the proposed test year expenses for property insurance, liability insurance, terrorism insurance, workers' compensation insurance, directors' and officers' insurance (D&O) and other risk management insurance. Please see Exhibit Staff/403 for a list of these various types of insurances and a chart comparing premiums for these insurances over the last five years.

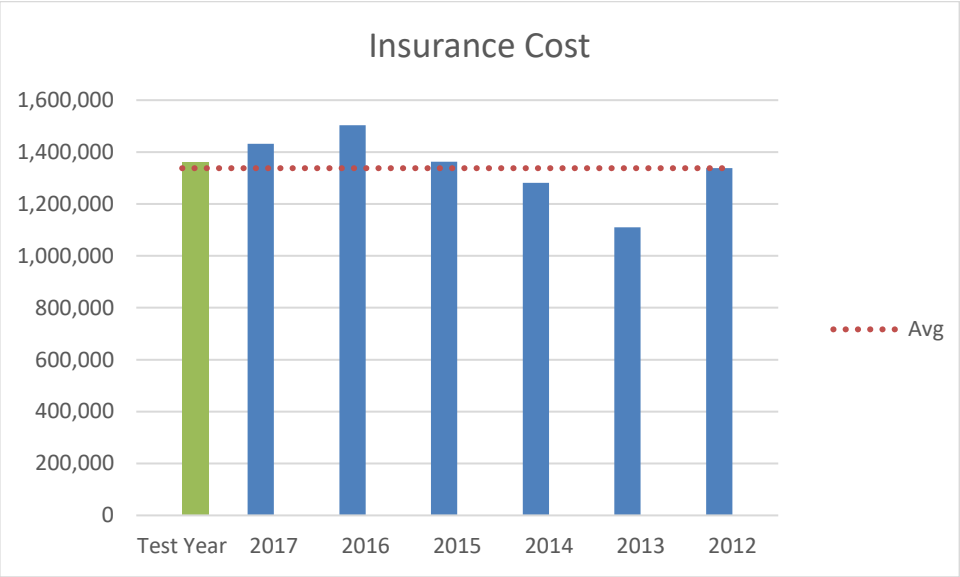
**Q. Have parties agreed to settle any aspects of insurance expenses?**

A. Yes, Staff has entered into a stipulation that resolves issues related to D&O insurance. That stipulation will be filed separately.

**Q. Is Staff proposing an adjustment involving any of the other types of insurances?**

A. No. In reviewing the premiums paid for each of the different types of insurance, Staff concluded that the Company's decision to carry these types of insurance is prudent and that the insurance premiums are reasonable, as they have fluctuated only slightly from year-to-year. There is no evidence that any of the insurances deviated drastically over the six-year period. Therefore, Staff has concluded that no adjustment is necessary. Figure 1 below shows the actual expenses over the last six years as compared to the test year.

*Figure 1*


Insurance Cost
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
0
Test Year
2017
2016
2015
2014
2013
2012
Avg

## ISSUE 2. LOAD FORECAST

**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 are forecasted separately: use-per-customer (UPC) and number of customers – where these components can be 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.

**Q. Describe the Company's primary forecast driver for residential UPC?**

A. Cascade uses weather as the primary forecast driver for UPC. 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.

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.

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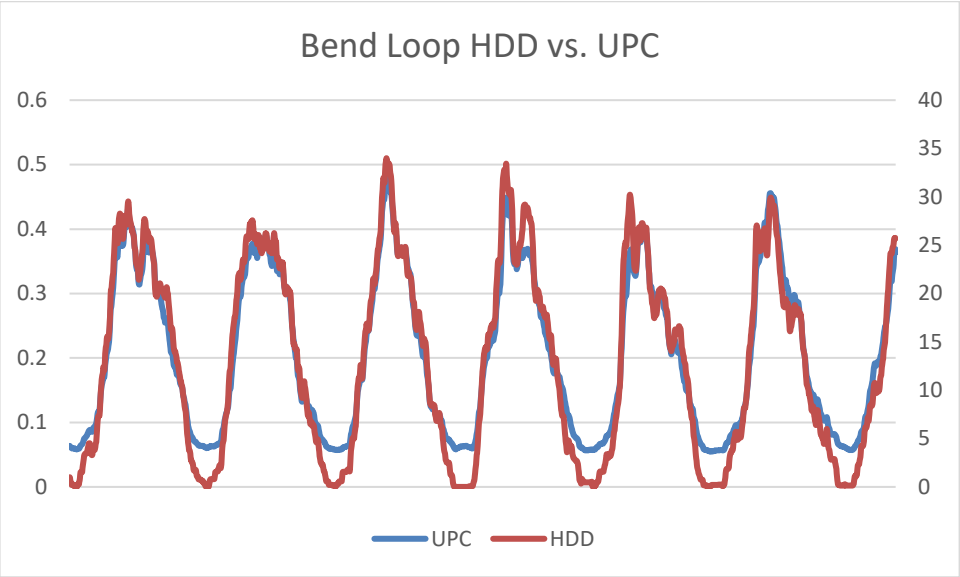
[1] Staff/402.
[2] *Ibid.*
[3] A "city gate" is a point or measuring station at which a gas distribution company receives gas from a pipeline company or transmission system.

*Figure 2*




**Q. Describe the Company's primary forecast driver for number of residential customers?**

A. Population and employment levels are the primary economic variables used as a forecast driver for the number of residential customers. The Company also includes monthly dummy variables when they are statistically important to the model. This basically accounts for any monthly differences in the data. The Company generally includes both population and employment variables but normally drops either population or employment as a variable from the model as one or the other is insignificant. This is because these two variables are correlated so one variable will tend to take on the majority of the explanatory value while the other one lacks any new information and is thus insignificant.

**Q. Did Staff propose any changes to the Company's forecasting methodology in its last rate case, Docket No. UG 305?**

A. Yes. Staff made four recommendations in UG 305:

1) Model each rate class individually.
2) Allow for non-linear weather effects on natural gas usage.
3) Eliminate outboard adjustments by including greater relevant data in the regression equations.
4) Address potential serial correlation problems in the regression equations.

**Q. Did the Company make any changes to its forecast drivers since UG 305?**

A. Cascade did not model each rate class individually but they do now separate customers by customer class (i.e., industrial, commercial, and residential) prior to forecasting. This is an improvement over simply performing the forecast by city gate. Cascade now derives coefficients for the impact of population and employment growth within the model as opposed to an outboard adjustment. And, Cascade utilizes an ARIMA model in order to account for potential serial correlation issues. Further, Cascade has changed their UPC model to daily data compared to monthly. Lastly, the modeling is now performed in SAS, a statistical analysis software, whereas it was previously performed in Microsoft Excel.

**Q. Does Staff support the changes made to Cascade's model?**

A. Yes, being that the majority of the changes were made based on Staff's recommendation, Staff's support should come as no surprise.

**Q. Does Staff make any recommendations to further improve the forecast?**

A. Yes. Staff continues to recommend incorporation of non-linear weather effects in the model. Staff also recommends that the model selection process be standardized using a computer algorithm available in SAS. Finally, Staff recommends the Company explore using Oregon residential new construction as a forecast driver for number of customers.

**Q. Why does Staff recommend the inclusion of non-linear weather effects?**

A. Customers' sensitivity to weather varies based on the weather; having the model allow for non-linear weather effects on usage can better capture this relationship. Additionally, this aligns with the approach of Oregon's other LDCs.[4]

**Q. Why does Staff recommend the use of an automated model selection process?**

A. Manual selection of the proper autogressive and moving average terms in an ARIMA model can be done utilizing any number of selection criteria, most commonly the Akaike information criterions (AIC). However most statistical packages including SAS come with algorithms that will automatically optimize the ARIMA model selection. This reduces the chance for human error and increases the ability of all parties to replicate and examine the model.

**Q. Why does Staff recommend the use of Oregon residential new construction in the model?**

[4] Avista and NWN use non-linear approaches: HDDs are squared in Docket No. UG 288 (Avista) and a piecewise function is used in NWN's 2016 IRP.

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 30.6 thousand dekatherms in the test year. Fourteen percent of that is made up of residential demand. Roughly sixty-four percent of the total forecasted throughput is forecasted to come from schedule 900 special contract large volume customers.

**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 2018 loads by either applying a one percent increase to its 2017 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 not 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.

## ISSUE 3. MISCELLANEOUS REVENUES

**Q. Please describe Cascade's miscellaneous revenues.**

A. The Company had $264,704 in other operating revenue in 2017 and added an adjustment of $24,715 to the test year for a total amount of $289,419. The Company calculates miscellaneous operating revenue as the sum of miscellaneous service revenue, service line modification, rent from gas property, interdepartmental rents, and other gas revenue. In the test year, miscellaneous service revenue represented 70 percent of the total. Miscellaneous service revenue includes revenue from the miscellaneous charges listed in Rate Schedule No. 200 in the Company's tariff. Examples include reconnection charges, late payment charges, and returned check charges.

**Q. How has the Company forecast its miscellaneous revenues?**

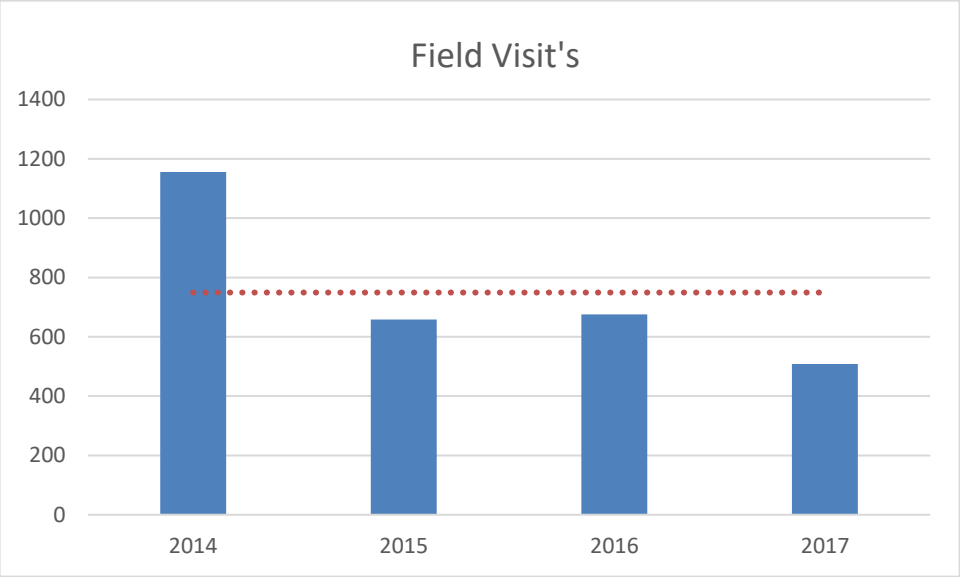
A. The Company started with its 2017 amounts and adjusted them to take into account additional revenue from proposed increases to two charges in Schedule 200. Cascade is proposing to increase its field visit charge and returned payment charge from $10 for each to $20 and $25 respectively. The Company used the number of instances of the two fees in 2017 to calculate the delta between the current and proposed amounts to determine the adjustment.

**Q. Does Staff agree with the new fees and proposed adjustment?**

A. Yes. The charges for a field visit seem in line with costs incurred by the Company and the charge for a return check fee is commensurate with amounts

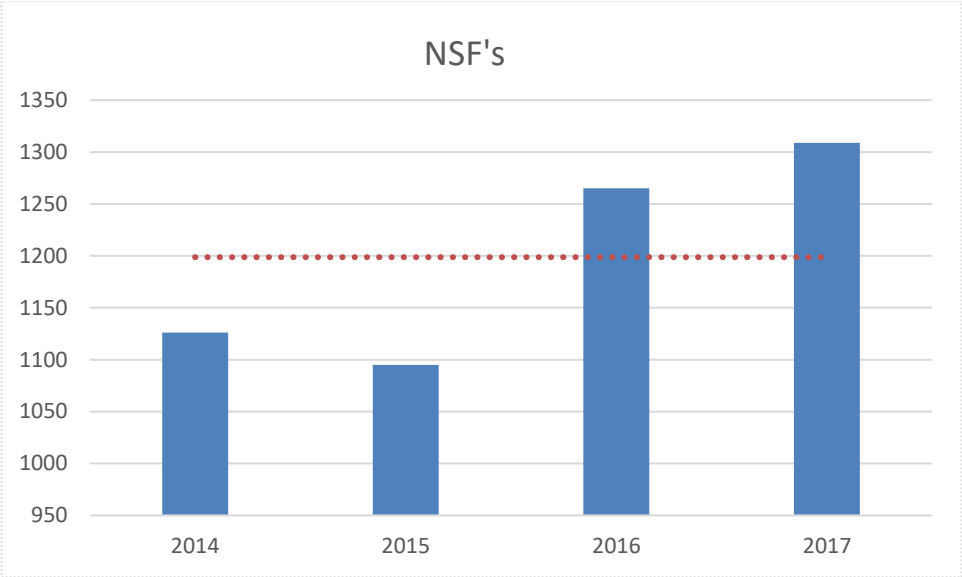
charged by other Oregon investor owned utilities.[5] Although the number of instances in a single year might not be representative of the average number of instances for a future year, Staff's review of the charges over time supports the adjustment amount. Figures 3 and 4 below show the number of instances of each charge. The red dotted line shows the average amount over the four years. The number of field visits in 2017 was lower than average, while the number of non-sufficient fund charges was higher than average in 2017. When taken together, a methodology that utilizes the average amount over four years results in a similar adjustment as the Company's proposal.

*Figure 3*




[5] CNGC/500, Archer/7.

*Figure 4*




**Q. Did Staff review any other aspects of miscellaneous revenues for potential adjustments?**

A. Yes. Staff reviewed miscellaneous revenues for both a trend analysis adjustment and a customer growth adjustment.

**Q. Please describe the customer growth adjustment.**

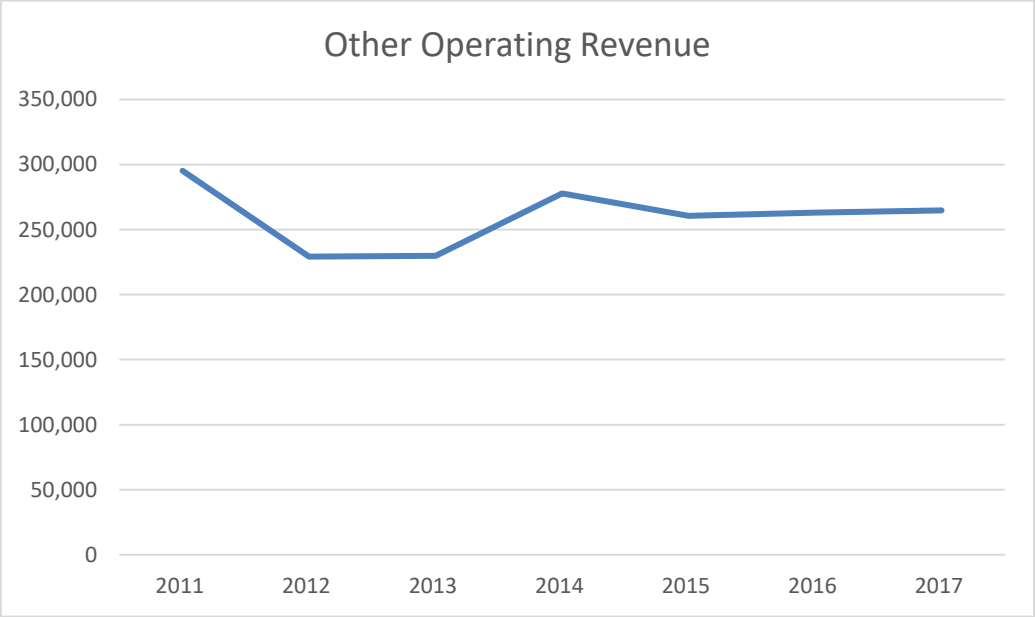
A. One adjustment Staff has previously argued for is based on the fact that customer accounts are usually forecasted to increase in the test year but normally not accounted for in miscellaneous revenues. Because miscellaneous revenues are customer driven, the argument is that as the number of customers increases these revenues will likely increase as well. In reviewing both the Company and Staff proposed customer forecasts, the amounts involved are such that an adjustment would be less than $3000 in total. Given the number of issues at hand and in an attempt to focus the Commission's and

parties' attention on more important issues, Staff did not propose an adjustment for new customers in this case.

**Q. Please describe Staff's trend analysis.**

A. Staff commonly will review an expense or revenue category over time to get a sense of how the base year and test year compare to other years. In reviewing this category it is evident that the revenue over time has been fairly steady. The figure below shows the revenue over the last seven years. The Company's proposal, which is based on 2017 values with an adjustment for new charges, seems reasonable.

*Figure 5*



## ISSUE 4. 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. 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.[6]

In Docket No. UG 305, Staff recommended that the Company explore adding non-linear weather effects to its decoupling mechanism because it can improve the accuracy of the model's description of normal weather. This recommendation was not included as part of the final stipulation but instead was an issue to consider during the full review of the mechanism in 2019.

**Q. Does Staff have any refinements of the decoupling mechanism to propose at this time?**

A. Yes, Staff continues to recommend the addition of non-linear weather effects, but also recommends exploring an adjustment for new customers. Like UG 305, Staff is highlighting a potential issue for the Company to consider when the full review of the mechanism is undertaken.

**Q. Why would an adjustment for new customers improve the decoupling mechanism?**

[6] See Docket No. UG 287, Order No. 15-412 at 5 (Dec. 28, 2015).

A. New customers tend to have lower baseline use than existing customers due to stricter building code standards, which are independent of the utility's energy efficiency policy. Extending decoupling to new customers beyond the number of customers forecasted in the rate case results in the following problems:

1. The decoupling adjustment will consistently be in Cascade's favor due to the average use of new customers being small relative to the average use of existing customers.
2. The decoupling mechanism will compensate Cascade for building code improvements and other forms of energy savings that are independent of Cascade.
3. The revenue associated with new customers will exceed the incremental cost of new customers because the average cost of serving all customers is higher than the incremental cost of serving an additional customer.

These problems arising from Cacade's current mechanism generally harm customers, while allowing the utility to recover more than the approved revenue requirement.

**Q. Is there evidence from other utilities that new customers do in fact utilize less energy on average?**

A. Yes. For example, PGE's Schedule 123 indicates that new customers are assumed to have 70 percent of the UPC of an average customer.[7] Further in

[7] See PGE Schedule 123. Available at: https://www.portlandgeneral.com/-/media/public/documents/rate-schedules/sched_123.pdf.

UG 325, Staff found that new Avista customers used roughly 25 percent less than current customers.[8]

**Q. Does this conclude your testimony?**

A. Yes.

[8] UG 325 Staff/600, St. Brown/24.

CASE: UG 347
WITNESS: SCOTT GIBBENS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 401

# Witness Qualifications Statement

# September 27, 2018

# 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 also handle analysis and decision making of affiliated interest and property sale filings, rate spread and rate design, as well as operational auditing and evaluation. 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 347
WITNESS: SCOTT GIBBENS

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 402

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

# CASCADE NATURAL GAS CUSTOMER AND DEMAND FORECAST MODEL

DESIGN DOCUMENT
6/1/2017

This document contains the forecast methodology and supporting documentation for the 20-year customer and demand forecast results generated as part of the combined load study.

## TABLE OF CONTENTS

## I. Overview

The purpose of this document is to discuss the methodology used for the customer, demand, and peak day demand forecast models for Cascade Natural Gas Corporation ("Cascade" or "Company"). The Company will also describe the underlying data used for each model, the sources of the data, how the data was scrubbed, and how the data was formatted for modeling.

## II. Data and Data Sources

### a. Customer Data

Customer data was gathered through Cascade's Customer Care & Billing ("CC&B") System. The file reports the customers broken out by 7 categories: CIS_Division (State), Town, Year, Accounting Month, MR_CYC_CD, SIC_CD, and Tariff. The Accounting Month indicates which month the data was billed. The MR_CYC_CD code is the cycle code that explains which billing cycle the data was on for that month. The SIC_CD is the Standard Industrial Classification ("SIC") code that explains what type of customer is behind that data. For example, MR_CYC_CD with code CA01 represents the cycle dates of January 4th to February 3rd. If the billed date is February 4th for this example, the data will be represented with an Accounting Month of February. Cascade will later explain how the data is matched to a calendar month.

### b. Demand Data

Demand usage data is gathered through the pipelines' Electronic Bulletin Board ("EBB") System. The three pipelines (NWP, GTN, and Enbridge) post daily usage data at the citygate level. The citygate is where Cascade takes ownership of the gas from the pipelines' distribution system into the Company's distribution system.

### c. Weather Data

Cascade utilizes Schneider Electric to gather daily weather data information. This data is gathered at seven weather locations: four in Washington and three in Oregon. The four in Washington are Bellingham, Bremerton, Yakima, and Walla Walla. The three in Oregon are Baker City, Redmond, and Pendleton. Normal weather is defined as the average daily temperatures of the most recent 30 years of historical data which results in the average annual temperatures as well. The company uses a heating degree day ("HDD") as the unit of measure

for temperature. HDD is calculated by taking the average temperature from a day and subtracting it from a reference temperature. If the reference temperature less HDD is negative, then the company gives that day a 0 for HDD. The company uses 60 °F as the reference temperature. For example, a 50 °F day will result in 10 HDDs (60-50).

### d. Population and Employment Data

The Company uses Woods & Poole Economics, Inc. ("W&P") for annual Population and Employment actuals and projections. The data is listed at the county level for both Oregon and Washington.

## III. Formatting

Cascade's data inputs for its customer and demand forecasts are in multiple different formats so the data must be converted into a usable and consistent format for use in Cascade's model. The CC&B data is at the town level, pipeline data is at the citygate level, weather data is at the weather location level, and the W&P data is at the county level. Since each of these inputs is broken out at different levels, Cascade must allocate and associate the data into a consistent format the Company can analyze in its model.

### a. Formatting Customer Care & Billing data for the Customer Forecast

To perform the customer forecast, Cascade must match the town data from CC&B to the county data of W&P. Prior to the allocation, Cascade must convert the therms and customers from an accounting month into calendar months. To do this, Cascade uses the monthly data from the pipelines and matches this to the CC&B therm data. Then, using the cycle codes, the data is shifted until it matches as close to the pipeline data as possible. The Company found that shifting the first thirteen billing cycles matched the data with approximately a 5% error. After the Company matches the CC&B data to a calendar month, Cascade matches the town to the county it belongs to and allocates all of the customers to that county. Cascade uses the Company's tariff to assign the customers into four groups: Residential, Commercial, Industrial, and Interruptible. Since W&P is an annual number, the same number for population and employment is applied to each month for the county. Cascade also gives an indicator value of one for each month excluding January. Once Cascade has the data formatted, the Company removes outliers from the data. Below is an example of the formatting for the customer

forecast in Table 1-1. Once the Company runs the forecast, the county data is allocated to the citygate level.

Table 1-1: Customer Forecast Format

| County | Class | Year | Month | count | Population | Employment | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Adams | Residential | 2004 | 1 | 1097 | 16.664 | 8.57 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Adams | Residential | 2004 | 2 | 1092 | 16.664 | 8.57 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Adams | Residential | 2004 | 3 | 1093 | 16.664 | 8.57 | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

## b. Formatting Pipeline Data for Demand Forecast

Cascade must also convert the pipeline data into a usable format. The data that is pulled from the pipelines is the core and non-core usage data at the citygate daily level. Cascade has a report that tracks the daily non-core data at the citygate level so the Company uses this to back out the non-core numbers leaving the core citygate data points. Once Cascade has the core data, the next step is to match the CC&B data to the citygate data. The Company uses an allocation that was determined based on past data to allocate the town level to the citygate level. Allocating the CC&B data to the citygate level allows Cascade to build monthly allocation percentages for the four customer classes. Using these allocation percentages, Cascade can determine the amount of therms that belong to each customer class for each citygate. After these steps, Cascade will have daily therm core usage by customer class. The next step is for Cascade to associate the weather data to each citygate. Cascade uses proximity to citygates and geographic similarity to determine which citygates belong to a weather location. After the weather data is associated to each citygate, the actual and forecasted customers are allocated to the citygates. Once Cascade has usage and customers, the usage is divided by customers to come up with a use per customer ("upc"). Cascade gives an indicator of "1" to weekend days and "0" to weekdays. Cascade is also giving an indicator of "1" for the month the data is in and a "0" otherwise for all months excluding January. An example of the formatting of upc for analysis is given in Table 1-2.

Table 1-2: Demand Forecast Format

| Citygate | Class | Year | Month | Day | Weekend | HDD | upc | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ACME | Residential | 2010 | 7 | 1 | 0 | 6 | 0.115493122 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 2 | 0 | 3.5 | 0.092394497 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 3 | 1 | 1 | 0.10394381 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 4 | 1 | 2.5 | 0.127042435 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 5 | 0 | 0 | 0.092394497 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 6 | 0 | 1 | 0.046197249 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 7 | 0 | 0 | 0.05774656 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 8 | 0 | 0 | 0.046197249 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 9 | 0 | 0 | 0.05774656 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 10 | 1 | 0 | 0.05774656 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 11 | 1 | 0 | 0.046197249 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| ACME | Residential | 2010 | 7 | 12 | 0 | 1 | 0.069295873 | 0 | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |

## IV. Customer Forecast

Cascade utilizes Autoregressive Integrated Moving Average ("ARIMA") models for the customer forecast as well as the demand forecast, which will be discussed in the next section. Below is the formula the Company uses to run the first regressions:

$$C_{Class}^{CG} = \alpha_0 + \alpha_1 Pop^{CG} + \alpha_2 Emp^{CG} + \alpha_m I_m + ARIMA\epsilon(p,d,q)$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class$
- $Pop^{CG} = Population\ by\ Citygate$
- $Emp^{CG} = Employment\ by\ Citygate$
- $m = month$
- $I = Indicator\ variable, where\ 1\ if\ the\ month\ indicated, 0\ otherwise. (Feb - Dec)$
- $ARIMA\epsilon(p,d,q) = Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d\ difference\ terms, and\ q\ moving\ average\ terms.$

Cascade runs this model for each of the 55 citygate and citygate loops by class where applicable. A citygate may only feed one or two classes. First, the Company checks for stationarity. If the data is non-stationary Cascade would difference the data, repeating the step until the data is stationary. Most times, the Company will not difference the data or difference it only once. Once the differencing is determined, Cascade runs the regression and checks for autocorrelation. Cascade uses the Autocorrelation Function ("ACF") and Partial Autocorrelation Function ("PACF") to determine moving average or autoregressive

terms for the model. Cascade would then remove non-significant variables. Typically, the model would only choose one of the two between population by citygate and employment by citygate. The Company noticed that if a non-significant monthly indicator variable was removed, the model would provide less robust results, therefore, some monthly indicator variables were left in even when non-significant. Cascade uses Akaike Information Criterion ("AIC") and Mean Absolute Percentage Error ("MAPE"), along with other statistics, in determining which model to use.

## V. Demand Forecast

As previously mentioned, Cascade utilizes ARIMA models for the demand forecast as well. Below is the model used for the demand forecast:

$$\frac{Therms}{C_{Class}^{CG}} = \alpha_0 + \alpha_1 HDD^{CG} + \alpha_m I_m + \alpha_w I_w + ARIMA\epsilon(p,d,q)$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class.$
- $HDD^{CG} = Heating\ Degree\ Days\ assigned\ to\ Citygate\ from\ Weather\ Location.$
- $m = month$
- $w = weekend$
- $I = Indicator\ variable, where\ 1\ if\ the\ month\ indicated, 0\ otherwise. (Feb - Dec)$
- $ARIMA\epsilon(p,d,q) = Indicates\ that\ the\ model\ has\ p\ autoregressive\ terms, d\ difference\ terms, and\ q\ moving\ average\ terms.$

Cascade runs this model for each of the 55 citygate and citygate loops by class where applicable. Cascade next runs the regression and check for autocorrelation. Cascade uses the ACF and PACF to determine moving average or autoregressive terms for the model. Cascade then removes non-significant variables. As with the customer forecast, Cascade uses AIC and MAPE, among other statistics, in determining which model to use.

## VI. Peak Day Forecast

To forecast peak day usage, the Company parses the data and uses the 3rd quartile of coldest days. Cascade removes the effects of warm weather on usage. After parsing the

data, Cascade runs linear regressions on the data with monthly indicators. Cascade uses the following formula for peak day forecasting:

$$\frac{Therms}{C_{Class}^{CG}} = \alpha_0 + \alpha_1 HDD^{CG} + \alpha_m I_m$$

Model Notes:

- $C_{Class}^{CG} = Customers\ by\ Citygate\ by\ Class.$
- $HDD^{CG} = Heating\ Degree\ Days\ assigned\ to\ Citygate\ from\ Weather\ Location.$
- $m = month$
- $I = Indicator\ variable, where\ 1\ if\ the\ month\ indicated, 0\ otherwise. (Feb - Dec)$

Cascade runs this model for each of the 55 citygate and citygate loops by class where applicable. The Company runs the model and remove non-significant variables. Similar to the customer and demand forecast, Cascade uses AIC and MAPE, among other statistics, in determining which model to use. Once the models are finalized, Cascade analyzes peak day using three different HDD scenarios; Average, System max, and Citygate max. The average peak day uses the average HDD from the coldest days in each of the past 30 years as an HDD for each weather location. System max peak day uses the coldest system wide peak day in the past 30 years, which was December 21, 1990. Citygate max finds the coldest day in the past 30 years and creates a hypothetical day where all weather locations experience the coldest day HDDs in the same day.

## VII. Final Product

After running each forecast, the Resource Planning analysts run a backcast to test for quality assurance. If any issues are identified, the Company will re-run those models. The Company produces a monthly customer and demand forecast and an annual peak day forecast for each of the 55 citygate and citygate loops. The forecasts are broken out by class: Residential, Commercial, Industrial, or Interruptible. In addition to using the forecast model for weather normalization in Cascade's rate case, Cascade uses the forecast model for Cascade's SENDOUT optimization model, citygate study, 5-year revenue plan, Purchase Gas Adjustment, and the Northwest Gas Association 10-year outlook report.

CASE: UG 347
WITNESS: DEBORAH GLOSSER

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 500

# Opening Testimony

# September 27, 2018

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

A. My name is Deborah Glosser. I am a Senior Utility Analyst employed in the Energy Rate, Finance and Audit Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High St. SE, Suite 100, Salem, OR 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. I present Staff's recommendations regarding the rate treatment of gas storage in rate base and "other gas supply expense," an issue related to the Integrated Resource Plan (IRP) process, and Cascade's proposed PGA commodity sharing adjustment.

**Q. Did you prepare additional exhibits for this docket?**

A. No.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## 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 the storage reservoir (or liquefied natural gas tank) to serve customer loads.[2] Cascade does not own its own storage facilities and 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 Cascade's and your proposed rate treatment of Cascade's gas storage costs.**

A. Cascade includes $181,298 for liquefied natural gas stored and $197,023 for prepaid gas storage in its rate base, which totals $378,121. This amount is the 2017 average of monthly averages for Cascade's working gas inventory.[4] Staff's calculations using this formula for natural gas stored underground and liquefied natural gas stored total $378,600.00.

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

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[1] *See, e.g.*, Docket No. UM 1651, Order No. 13-349 (Sept. 30, 2013).
[2] *Id.*
[3] Cascade Response to Staff DR No. 230 (Docket No. UG 347).
[4] CNG/209.

A. In Cascade rate case Order No. 77-125, the Commission identified gas in storage as an asset that should be in rate base.[5] In the past, Staff has recommended that working gas inventory costs be recovered through a gas utility's Purchase Gas Adjustment (PGA); however, after investigation, Staff concluded that the benefit obtained by updating the level of working gas inventory each year does not warrant a complicated adjustment to the PGA mechanism.[6] Currently, the Commission has approved stipulations for all three of Oregon's regulated gas utilities that include working gas inventory costs in rate base.[7] Staff does not oppose including the cost of working gas inventory in rate base.

**Q. Please summarize your analysis of the amount that should be included in rate base for gas storage.**

A. Based on my analysis, I agree that the amount included in the test year is reasonable.

[5] Docket No. UF 3246, Order No. 77-125 (Feb. 22, 1977).
[6] Docket No. UG 287, Staff/400, Colville/2-3 (July 31, 2015).
[7] *See* Docket No. UG 305 Order No. 16-481 (Dec 16, 2016); Docket No.UG 325, Order No. 17-344 (Sept 13, 2017)).

**ISSUE 2. OTHER GAS SUPPLY EXPENSE (FERC ACCOUNT 813)**

**Q. What is other gas supply expense?**

A. Other gas supply expense is expense recorded in FERC Account 813 and includes the cost of labor, materials used, and expenses incurred in connection with gas supply functions, including research and development expenses, not provided for in any other FERC account for gas expense.[8]

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

A. Cascade proposes to use its total other gas supply expense for calendar year 2017 inflated by .017 (All-Urban CPI, March 2018) for the test year expense[9].

**Q. Please summarize Commission historical treatment of other gas supply expense.**

A. I was not able to find a Commission order expressly addressing the ratemaking treatment of "other gas expense" that should be included in revenue requirement. In Cascade's last general rate case, Staff proposed weighing the previous three years' expense results more heavily than a long-term trend, unless there is a reason not to do so. I apply the same rationale and analysis in this case and conclude that no adjustment to the amount proposed by Cascade is warranted.

**Q. Please summarize your proposed adjustment to other gas supply expense.**

[8] See 18 C.F.R. FERC Account 813.
[9] See CNGC/301-306.

A. I have no proposed adjustment to other gas supply expense.[10]

[10] See Staff/402 for a detailed description of Staff's analysis.

**ISSUE 3. UNDERGROUND STORAGE EXPENSE (FERC ACCOUNTS 814-837)**

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

A. No expenses in FERC accounts 814-837 are requested in this rate case.

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

A. Cascade does not propose an amount for underground storage expense. I have no proposed adjustment.

## ISSUE 4. PURCHASED GAS EXPENSE

**Q. Please describe your proposed adjustment of purchased gas expense.**

A. The actual cost of gas is reconciled with customers each year in the Purchased Gas Adjustment (PGA).[11] Therefore, I have no proposed adjustment for this rate case issue at this time.

[11] Docket No. UM 1286, Order No. 14-238 (June 24, 2014).

## ISSUE 5: PGA COMMODITY SHARING ADJUSTMENT

**Q. Please summarize Cascade's proposal related to adjusting the PGA commodity sharing.**

A. Cascade presents a downward adjustment of $198,081 to operating revenues to reflect a reduction in the amount of PGA commodity sharing due to commodity costs being less than forecasted in the PGA for the 2017-2018 gas year.[12] The Company explains that the 2016 actual gas costs were lower than the commodity rate built into the PGA, therefore, the Company benefited. However, there is then a mismatch between revenues and gas costs associated with the 10 percent that would not exist if no sharing were required. If no sharing were required, then this 10 percent mismatch would not be a factor, so the PGA cost sharing adjustment simply brings these numbers into equilibrium. The adjustment is required to match the revenues with the associated expenses.

**Q. Do you propose an adjustment to Cascade's commodity sharing adjustment?**

A. I confirmed that the PGA Commodity Sharing Adjustment in column (e) of the Proposed Adjustments to Base Year Results was correctly calculated. Therefore, I have no proposed adjustment to that amount.

**Q. Does this conclude your testimony?**

A. Yes.

[12] CNGC/301-306.

CASE: UG 347
WITNESS: DEBORAH GLOSSER

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 501

# Witness Qualifications Statement

# September 27, 2018

# WITNESS QUALIFICATION STATEMENT

NAME: Deborah Glosser

EMPLOYER: Public Utility Commission of Oregon

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

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Bachelor of Arts, Computational Linguistics, The Ohio State University
Juris Doctorate, Law, Duquesne University
Master of Science, Geophysics, University of Pittsburgh

EXPERIENCE: I have been employed at the Oregon Public Utility Commission (Commission) since October of 2016. My responsibilities include providing engineering and model analysis for filings made by electric utilities, related to their system operations and resource procurement and planning. Prior to working for the Commission I was a research geophysicist fellow at the United States Department of Energy. There, I developed physical and statistical models related to fossil energy resources. I published several peer review and technical papers related to energy exploration. I also served as a technical expert on a national laboratory task force, where we were tasked with developing science based recommendations to inform the improvement of federal regulation of underground natural gas storage well safety. Prior to my work at US DOE, I worked as an attorney in private industry.

CASE: UG 347
WITNESS: MITCHELL MOORE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 600

# Opening Testimony

# September 27, 2018

**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 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. The purpose of my testimony is to address Cascade's request to approve deferred accounting for expenses incurred for review of its pipeline system records and to amortize those deferred expenses into rates. I argue that deferred accounting is not appropriate for these expenses and therefore recommend removing $116,724 from the revenue requirement.

I also summarize and present my conclusions regarding my review of operating expense associated with customer accounts, customer service, and advertising and promotional activities as well as a prudence determination of costs associated with environmental cleanup of Cascade's Manufactured Gas Plant (MGP) in Eugene.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

**ISSUE 1. DEFERRAL AND AMORTIZATION OF PIPELINE RECORDS EXPENSE**

**Q. Please summarize this issue.**

A. On January 6, 2017, Cascade filed an application, docketed as UM 1816, seeking authorization for deferred accounting treatment of one-time expenses incurred to hire a contractor to perform a records review of Cascade's high pressure distribution and transmission pipelines. According to the application, the purpose of the records review was to verify that all of Cascade's records meet all federal and state regulations regarding maximum allowable operating pressures (MAOP).

At the time of its deferral application, the Company expected the records review to cost between $950,000 and $1,000,000. Once completed, the actual cost of the review was approximately $525,000. With this filing, UG 347, Cascade seeks recovery of these costs through a five-year amortization of $116,724 each year.

**Q. What is deferred accounting?**

A. Deferred accounting is an extraordinary form of ratemaking whereby revenues received or expenses incurred are either refunded to customers or recovered from customers in future rates. Normally, ratemaking is forward-looking, in that rates are set prospectively based on a forecast of future costs. Both federal and Oregon law typically forbid "retroactive ratemaking," where past costs or revenues are used as a basis for setting future rates. However, ORS 757.259 provides for an exception to this rule through deferred accounting. The

Commission may approve a utility's request for deferred accounting in limited circumstances.

**Q. Does Staff believe Cascade's request for deferred accounting in this instance is appropriate?**

A. No. Staff did not forward to the Commission a recommendation to approve the Company's request in UM 1816. In fact, Staff requested that the Company withdraw its application because it does not meet previously established Commission thresholds that support the need for this extraordinary form of ratemaking.

**Q. What is the basis for Staff's position regarding this expense?**

A. Fundamentally, Staff opposes deferred accounting treatment in this case because an extraordinary form of ratemaking is not appropriate for general operating expenses associated with a utility's core function. Staff believes that keeping accurate and up to date records on its pipeline system according to federal law is a core function in a gas utility operation. While Staff commends the Company for acting proactively regarding its high-pressure pipeline records, Staff believes that the rates in effect at the time these expenses were incurred should be presumed to include expenses associated with the core utility function of record keeping.

It is the Company's responsibility to manage its operating expense, and it is not appropriate or consistent with standard rate regulation to request cost recovery for higher than expected operating expense in future rates. This contradicts the basic principles of prospective ratemaking, in which the utility

bears the risk of managing its costs against expected revenues. The utility should not be allowed to transfer that risk, when expenses exceed expected revenues, onto ratepayers retroactively.

**Q. What arguments does Cascade provide in support of this request in its testimony?**

A. Michael Parvinen testified regarding the reasons the costs were incurred and provides a number of statements regarding the benefits of the records review.[1] Many expenses incurred by the Company result in benefits to customers. The issue in this case is whether these expenses meet the Commission's standards for deferral. The testimony provides no justification for why this previously incurred operating expense should be recovered in future rates.

**Q. Has the Company made other arguments in support of this request outside this proceeding?**

A. Yes. In prior discussions with Staff regarding the Company's deferral application in Docket No. UM 1816, Cascade has argued that the expense at issue is a one-time significant expense for a project related to Cascade's compliance with new federal regulations on record-keeping. Cascade asserts the need to update the records is associated with meeting updated safety guidelines, and therefore is appropriate for future recovery. The Company has explained that it did not contemplate incurring this expense when preparing its previous rate case, and thus believes the costs for the records review is not accounted for in rates.

[1] CNGC/200, Parvinen/5-7.

**Q. How would Staff respond to the Company's argument?**

A. Staff agrees that the incurred expense is justifiable and necessary. However, with respect to the argument that the expense was relatively significant and not predicted in the rates in effect at the time, Staff's opposition relies on previous Commission orders that address both the type of expense and the magnitude of an unexpected expense that a utility could be expected to absorb as a reasonable risk of doing business.[2]

**Q. How does Commission precedent apply in this case?**

A. In Order No. 04-108, the Commission established its two-stage review for deferral applications filed under ORS 757.259(2)(e). Under the first prong, the utility must establish the proposed deferral will either (1) minimize the frequency or fluctuations of rate changes, or (2) match the costs and benefits received by ratepayers. Staff would agree that the first prong is satisfied in this instance because the cost of updating the records matches a corresponding benefit to ratepayers.

The second prong entails an exercise of Commission discretion, in which the Commission considers two interrelated factors: the type of event that caused the deferral and the magnitude of the event's effect. With regard to the type of event that caused the deferral, the Commission distinguishes between risks that can be predicted to occur as part of the normal course of events, classified as stochastic risks, and risks that are not susceptible to prediction and quantifiable, classified as scenario risks. Risks that are reasonably

[2] See Order Nos. 04-108 and 05-1070.

predictable and quantifiable - stochastic risks - are generally not appropriate for deferral unless the second consideration, the magnitude of the financial impact of the event on the utility, is substantial enough to warrant deferral.

Staff believes the expense incurred in this instance constitutes a stochastic risk. The core utility function of record keeping is a generally predictable expense that the Company should expect to incur. To the extent that the Company in managing operating expense from year to year must incur a larger expense than usual to bring the records into compliance with federal regulations does not constitute an unpredictable event as defined by the Commission. The expense associated with record keeping is quantifiable and predictable, and therefore should be presumed to be modeled in rates.

The Commission has declined to set a numerical criterion establishing a threshold for “substantial” impact associated with a stochastic risk. However, the Commission has concluded that excess net variable power costs equal to 250 basis points of ROE represents the amount a utility can reasonably be expected to absorb between rate cases.

The financial impact to the utility here is approximately 61 basis points of ROE, an amount that is significantly less than the 250 basis points of ROE the Commission has previously concluded is a reasonable amount for a utility to absorb between rate cases. Therefore, Staff argues the financial impact on the utility in this case is not substantial enough to warrant deferred accounting.

**Q. What is Staff's recommendation?**

A. Staff recommends the Commission deny approval of Cascade's request for deferred accounting in Docket No. UM 1816. Cascade has included amortization of the deferral amounts in its test year expense. Accordingly, Staff also recommends an adjustment of ($116,724) to the test year expense in this case.

**ISSUE 2. CUSTOMER ACCOUNTS, CUSTOMER SERVICE, AND ADVERTISING AND PROMOTIONAL EXPENSE**

**Q. What is Customer Accounts Expense?**

A. This category of operating expense refers to the supervisory, labor and other expenses associated with such activities as meter reading, maintaining customer records, work on customer applications, account billing and collections. This review is limited to non-labor expenses. Labor expense for these accounts is addressed in Staff witness Marianne Gardner's testimony in Staff/100.

**Q. Please describe Cascade's proposal and Staff's review of Customer Accounts expense?**

A. Cascade essentially begins with its 2017 base year expenses and escalates with an inflation factor to achieve its forecasted test year expense. Cascade identifies approximately $605,448 in 2017 expense for this category. I reviewed line item transaction data for 2017 for these accounts and did not find any expenses that appeared questionable. I also compared 2017 expenses with 2015 and 2016 spending and found non-labor expenses to have decreased approximately four percent from 2016 and 2015.

**Q. What does Staff conclude from this review?**

A. Staff concludes the expenses are reasonable and appropriate. I do not recommend any adjustment for these accounts.

**Q. Please describe your review of expense for customer service, advertising and promotional activities.**

A. As with customer accounts expense, I reviewed line item transaction data for each of the accounts associated with these activities. Commission rules in OAR 860-026-0022(3) distinguish between different types of advertising and apply different criteria to each category to determine reasonableness. Cascade provided advertising detail broken down by category and I was able to determine that these expenses were reasonable and consistent with Commission rules.

**Q. What does Staff conclude from its review?**

A. I conclude that these expenses are reasonable and appropriate. I do not recommend any adjustment for these accounts.

**ISSUE 3. PRUDENCE REVIEW OF ENVIRONMENTAL CLEAN UP EXPENSE**

**Q. Please summarize this issue and Cascade's proposal.**

A. Cascade shares liability with Eugene, Water and Electric Board and PacifiCorp for environmental cleanup to a Manufactured Gas Plant (MGP) site located in Eugene, Oregon. The three companies have a cost sharing agreement for site investigation, remedial design, and remediation activities. [3] Cascade has been deferring costs associated with this project in Docket No. UM 1636 and in its last general rate case, Docket No. UG 305, began a three-year amortization of the deferred balance that had accrued to date.

With this filing, Cascade proposes to combine the remaining unamortized balance authorized in Docket No. UG 305, approximately $54,000, with the current deferred balance of approximately $193,000, and amortize the total balance of $247,000 over three years. The Company proposes an update to Schedule 197 to reflect a three-year amortization of the total balance, collecting $84,858 per year. Because of an increase in projected gas volumes, the rate per therm in the schedule would decrease from the current $0.000514 to $0.000303.[4]

**Q. Please describe Staff's review.**

A. I reviewed the Company's response to several data requests, in which the Company provided detailed line item transaction of expenses incurred and revenues received for this deferral period, and reviewed the interest

[3] See CNGC/200, Parvinen/9, footnote 4.
[4] See Exhibit CNGC/202.

calculations. As with other environmental remediation prudence reviews, I checked to ensure the reported expenses were: a) actually incurred; b) solely incremental; and c) associated with the environmental remediation activities required for this project.

**Q. What does Staff conclude from its review?**

A. In reviewing these expenses I conclude that they are incremental, reasonable and associated with the required investigation and design remediation activities. I also recommend that the Commission approve the requested update to Schedule 197 and allow amortization of the deferred balance to occur over the proposed three-year period.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UG 347
WITNESS: MITCHELL MOORE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 601

# Witness Qualifications Statement

# September 27, 2018

# WITNESS QUALIFICATION 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 (1992)

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.

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 347
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 700

# Opening Testimony

# September 27, 2018

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

A. My name is Sabrinna Soldavini. 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/701.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to address Cascade's methods of cost allocation among its affiliates and state jurisdictions.

**Q. Did you prepare an exhibit for this docket?**

A. Yes. I prepared Staff/702, Cascade's 2017 Cost Allocation Manual, Staff/703, Cascade's 2015 Cost Allocation Manual, Staff/704, NARUC Guidelines for Cost Allocations and Affiliate Transactions, and Staff/705, Data Request Responses.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1. 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".[1]

Staff analyzes the Allocation Manual for reasonableness and prudence in how costs are allocated between Cascade and its affiliates. 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.[2] Additionally, Staff reviews any cross charges to ensure costs allocated to the Company have been done so correctly and justifiably.

[1] See OAR 860-027-0048(6).
[2] *See* Exhibit Staff/704.

**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 all applicable formulas and models to verify Oregon is being allocated costs based on the actual burden caused by the Oregon jurisdiction to ensure Oregon ratepayers are paying only their share of costs.

**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 authorized MDUR to purchase Cascade in 2007.[3] 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.

Montana Dakota/Great Planes (MDU) provides leadership, customer services, information technology, administrative services, and gas supply and control to Cascade. Intermountain Gas provides the use of a customer care

[3] *See* Docket UM 1283, Order 07-221.

center. Centennial Holdings Capital LLC carries liability insurance policies for Cascade. Knife River Corporation provides asphalt services for Cascade.

| Affiliate | Service(s) Provided to Cascade |
|---|---|
| MDU Resources Group, Inc. (MDUR) | Payroll, Procurement, Enterprise Technology, Administrative & General Services |
| Montana Dakota/Great Planes (MDU) | Leadership, Customer Services, Information Technology, Gas Supply & Control |
| Intermountain Gas | Customer Care Center |
| Centennial Holdings Capital LLC | Liability Insurance Policies |
| Knife River Corporation | Asphalt Services |

**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/702. 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."[4]

**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, Procurement Shared Services, Enterprise Technology Services (ETS), and staff that perform general and administrative services.

**Q. How are costs for these shared services allocated?**

[4] *See* Exhibit Staff/702, Soldavini/4.

A. Costs for Procurement Shared Services are allocated among MDUR subsidiaries based on ratios of five categories, all carrying an equal weight of 20 percent. Those factors are: number of Visa cards as of 8/1/16, total Visa spend for 2015, national account spend for 2015, number of construction equipment acquisitions in 2015, and the number of fleet acquisitions in 2015. Cascade's total weighted allocation factor for procurement shared services is 7.53 percent.[5]

Costs for Payroll Shared Services are charged based on the number of employees paid. Enterprise technology services (ETS) provided by MDUR for its subsidiaries include several departments that are allocated using their own distinct factors. For example the customer relations group within ETS allocates costs based on the percentage of total devices for each company that are supported by customer relations. Cascade's allocation rates for ETS range from 3.34 to 13.6 percent.[6]

General and administrative 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 2017 is 13.6 percent.

[5] *See* Exhibit Staff/702, Soldavini/16.
[6] *See* Exhibit Staff/702, Soldavini/16-18.

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, Administrative Services, and Gas Supply & Control. Labor costs for these services are shared between MDUR's utility subsidiaries and not shared with non-utility subsidiaries.

Exhibit IV of the Allocation Manual states that costs for Vice Presidents, Directors, managers and team leads of the Leadership Group and Customer Services are allocated to Cascade at ratios from 25 to 35 percent. For example, in Exhibit IV of the Allocation Manual, leadership group costs are said to be allocated evenly across all brands. According to this exhibit, Cascade is also allocated 30 percent of the scheduling manager costs and 35 percent of the Customer Services Director costs. The allocation manual states these ratios are based on "estimated time using history."[7]

However, based upon Staff inquiry in Data Request 287 and follow up conversation with the Company, it was determined that Exhibit IV of the 2017 Cost Allocation Manual does not accurately reflect how these labor costs for Utility Operations and Support are allocated among Cascade and its affiliates. These costs are in fact allocated based upon cost driving functions such as customer counts, call times, and credit to-do's (accounts up for severance, closed accounts pending write-off, and broken payment plans) reviewed on a

[7] *See* Exhibit Staff/702, Soldavini/19.

yearly basis. For example, based on the data provided by the Company in response to data requests, the Customer Service Director's costs are allocated based on the customer count rather than being split according to historical estimates of time spent on each brand. Similarly, the allocation of costs for Customer Service Supervisors and Managers are also based on customer count rather than the 30 percent allocation based on estimated time reflected in the Cost Allocation Manual, and the credit team's costs are based on credit to-do's rather than the amount of time spent on each brand.[8]

**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. However, Staff takes issue with the fact that the 2017 Allocation Manual is inaccurate. Specifically, Exhibit IV of the document.

The 2017 Cost Allocation Manual was filed with Cascade's 2017 Affiliated Interest Report and Staff expects that these filings be kept up to date and accurate.[9] Exhibit IV of the Allocation Manual has not been updated from the 2015 Cost Allocation Manual.[10] Staff contends the Company should be able to submit accurate Cost Allocation Manuals with its filings, particularly as the issue of allocations being made irrespectively of cost driving functions was a

[8] See Exhibit Staff/705, Cascade Response to DR No. 287.
[9] *See* Docket RG 44(6) – Cascade Natural Gas Company's 2017 Affiliated Interest Report.
[10] See Exhibit Staff/703, Soldavini/31.

point of Staff's concern in Cascade's last rate case.[11] Furthermore, OAR 860-027-0048 requires that an energy utility keep a current Allocation Manual with the Commission.

**Q. How is ownership of assets distributed and how are associated costs allocated?**

A. Some assets 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. How are costs allocated between the two state jurisdictions?**

A. The Company operates in two state jurisdictions: Oregon and Washington. Cascade uses the financial software JD Edwards (JDE) to create a monthly automated allocation process between the jurisdictions. 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 2018 test year, as filed, is 25.15 percent of the costs

[11] *See* Docket No. UG 305 Staff/1000, Kaufman/7.

shared between jurisdictions.[12] In some instances the customer ratio, employee ratio, gross plant ratio, or rate base ratio alone may be used to allocate costs between the two state jurisdictions.

**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 provide a summary of the Company's filed proposal for cost allocation.**

A. The Company does not address cost allocation in testimony. Staff sent several data requests addressing the issue of cost allocation to determine and review the methods and formulas Cascade utilizes to allocate costs both to and from its affiliates, as well as how Cascade allocates costs between its two state jurisdictions: Oregon and Washington.

**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

[12] *See* Exhibit Staff/705, Cascade Response to DR No. 119.

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, and all revenue requirements used to allocate costs to and from affiliates.

To analyze the Company's affiliate allocations, Staff reviewed all cross charges to Cascade from its affiliates. A review was also conducted of all revenue requirement models used in the calculation of charges for shared services from/to its affiliates. For example, Staff reviewed the methods and formulas used in the revenue requirement model used by Cascade to allocate costs to IGC and MDU for shared use of its Kennewick General Office. Additionally, Staff had follow up conversations with employees at Cascade to review revenue requirement model assumptions.

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.

Further, Staff looked into issues raised by Staff in Cascade's last rate case such as issues of transparency in reporting how costs are allocated.[13] In relation to cost allocation only, Staff finds no serious issues in transparency

[13] *See* Docket No. UG 305 Staff/1000, Kaufman/6.

and level of detail at this time. The Company was able to identify cross charges from affiliates in the data provided, and Staff was able to identify which allocation methods were used to assign costs between state jurisdictions.

**Q. Does Staff propose an adjustment to the proposed 2018 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. However, Staff would like to ensure the Cost Allocation Manual on file with the Commission be updated to reflect the current methodology as required by OAR 860-027-0048.

**Q. Does this conclude your testimony?**

A**.** Yes.

CASE: UG 347
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 701

# Witness Qualifications Statement

# September 27, 2018

# WITNESS QUALIFICATION STATEMENT

NAME: Sabrinna Soldavini

EMPLOYER: Public Utility Commission of Oregon

TITLE: Utility Economist
Energy Rates, Finance and Audit Division

ADDRESS: 201 High St. SE Ste. 100
Salem, OR 97301-3612

EDUCATION: Masters 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 (Commission) since August 2018 in the Energy, Rates and Finance Division. My responsibilities include providing research, analysis, and recommendations on a range of regulatory issues for filings made by utilities.

Prior to working for the Commission I was a consulting analyst for MGT Consulting, primarily to help large public school districts prepare for bond proposals through budget analysis and statistical modelling/projections of student and demographic data. Prior to this work, 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 347
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 702

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

# Cascade Natural Gas

## Cost Allocation Manual

## 2017

CASCADE NATURAL GAS CORPORATION®

A Subsidiary of MDU Resources Group, Inc.

*In the Community to Serve®*

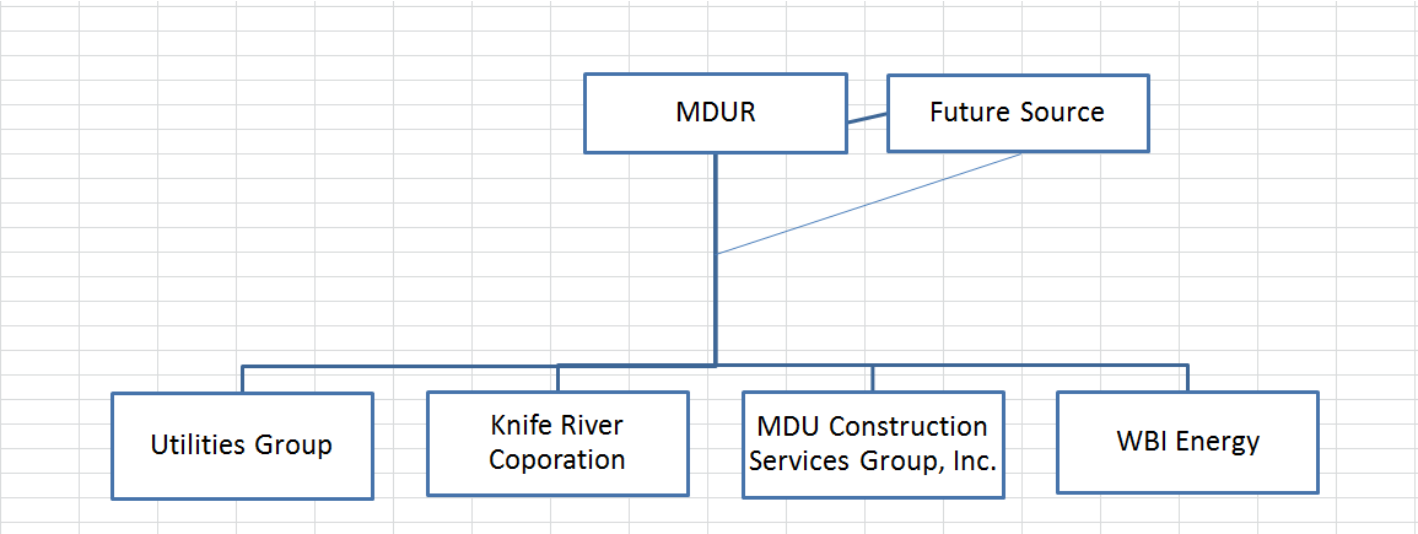
## Table of Contents

## Overview

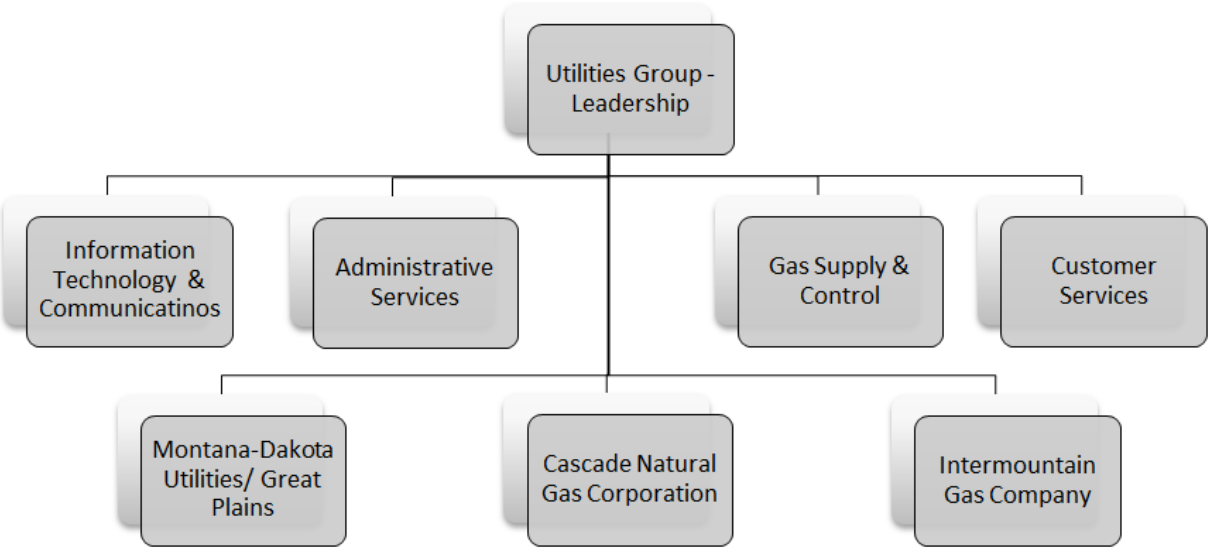
Cascade Natural Gas Corporation (Cascade), a subsidiary of MDU Resources Group, Inc. (MDUR), conducts business in two states with regulated gas distribution operations.

Below is an overview of the operational structure for the purpose of assigning costs. The diagrams presented are intended to provide an overview for cost allocation only and are 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.)

# Corporate Level



# Utility Group Level




This document is intended to provide an overview of the different types of allocations and the processes employed to direct costs to the proper utility and state jurisdiction for Cascade.

This document will discuss the allocations from:

- MDUR and FutureSource to Cascade Natural Gas
- Montana-Dakota/Great Plains (MDU) and Intermountain Gas Company (IGC) to Cascade Natural Gas
- Cascade to MDU and IGC
- 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, procurement and enterprise 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 III)
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 Cascade, the payroll shared services department is also responsible for the accumulation of time entry records and maintenance of employee records. Cascade does not have any departments that provide these payroll related services.

### Procurement Shared Services

Procurement Shared Services 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 of the Corporation's operating companies. National accounts, or preferred vendor agreements, typically are negotiated at the corporate level rather than at the local company level. Procurement Shared Services also is responsible for monitoring the level of services, quantities, discounts and rebates associated with established national accounts. Cascade has a single procurement department that places specific purchase requests for materials and services required to conduct business with approved vendors.

### Enterprise Technology Service

Enterprise Technology Services (ETS) provides policy guidance, infrastructure related IT functions and security-focused governance. ETS seeks to increase the return on investment in technology through consolidation of common IT systems and services, while eliminating waste and duplication. ETS 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.

Cascade's IT department consists of Montana-Dakota/Great Plains employees physically located in Kennewick, Washington, Boise, Idaho, and Bismarck, North Dakota. This Department is responsible for supporting applications specific to the utility group such as the Customer Care & Billing System, the JD Edwards financial software, Scada and mobile applications, Enterprise GIS, and PowerPlan which is the project and fixed asset accounting software. In addition the utility group IT department develops business continuity plans in the case of disaster recovery.

**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
- Travel
- Treasury services

Cascade receives an allocation of these corporate costs. Corporate Policy No. 50.9 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. 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 is reflected as CNGC 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.

The corporate costs allocated to Cascade are subsequently allocated to the state jurisdictions. Corporate costs are recorded in the administrative and general (A&G) function for Cascade. (See state jurisdictional allocation discussion on page 8.)

## Montana-Dakota/Great Plains 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. The costs are allocated based on the number of customers served by each utility.

Intermountain Gas owns the customer care center located in Meridian, ID. To cover the cost of ownership and operating costs associated with that owned asset, a revenue requirement (asset return plus annual operating expenses) is computed similarly to Montana-Dakota owned 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 Montana-Dakota/Great Plains and Cascade as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Certain Cascade owned assets, such as the portion of the General Office facility used for Shared Services (i.e. Gas Control, IT), located at the utility headquarters in Kennewick, 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 MDU and IGC, as a monthly fee. The costs are allocated based on the number of customers served by each utility.

### 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)
- Information Technology and Communications- (Management Information Systems, Technology and Compliance)
- Administrative Services - (Procurement, Office Services, Fleet Operations)
- Gas Supply & Control

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 IV.

## Standard Labor Distributions

### Labor/Reimbursable expense allocations

The development of standard labor distributions for Cascade 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 jurisdiction where possible. If the expense is not direct, the appropriate jurisdiction is charged as follows:

#### *Union Employees*

Time tickets are required for productive time. The employee specifies the proper 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.

***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 based on an expected ratio of work. 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 periodically.

## Cascade Allocations to State Jurisdictions

Cascade 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. The allocation process creates a Journal Entry to the JD Edwards jurisdictional ledgers established by state.

The allocation methodology is as follows:

The JD Edwards (JDE) software is used by Cascade 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 (i.e. gas regulator station), or department (i.e. human resources, engineering).

Object – 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.

Subsidiary – The subsidiary portion of the account for O&M accounts identifies the utility segment (2 represents gas) 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.

Revenue Accounts – Revenues are directly assigned to the jurisdiction when possible. The applicable FERC account is part of the account structure. It is the combination of the business unit, 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), 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) 47041 represents the geographic location of the Bend, Oregon District. The Bend District is therefore directly assigned to Oregon for all FERC accounts.

Another example is location 4767000, representing the Credit and Collections Department. The allocation of costs is based on the FERC range of accounts. The location may also be a responsibility, or department. An allocation code is used to split the costs between the states. The most common allocation factor is the 3-factor formula (customer, employee and plant). However, the customer ratio, employee ratio, gross plant ratio, and rate base ratio are also used. See Exhibit II for the allocation factor calculations.

| | *Co | *Location | *Obj Acct | *FERC Sub 1 | *FERC Sub 2 | *Start Date | Stop Date | Description | Utility Alloc Code | Utility 01 | Allocation Code 01 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ◉ | 00047 | 47041 | | 2870 | 29359999 | 200601 | 203512 | Central OR District | 00002 | 2 | 00038 |
| ○ | 00047 | 47041 | | 4261 | 42659999 | 201208 | 203512 | Bend District-BTL | 00002 | 2 | 00038 |
| ○ | 00047 | 47041 | 4081 | 0 | 99999999 | 200601 | 203512 | Central OR District-4081 | 00002 | 2 | 00038 |
| ○ | 00047 | 47041 | 5981 | 4261 | 4261 | 200902 | 201207 | Central OR District | 00002 | 2 | 00038 |
| ○ | 00047 | 47041 | 5984 | 4263 | 4263 | 201111 | 201207 | OR 5984 | 00002 | 2 | 00038 |

**Code 00038 = 100% allocated to Oregon**

| | *Co | *Location | *Obj Acct | *FERC Sub 1 | *FERC Sub 2 | *Start Date | Stop Date | Description | Utility Alloc Code | Utility 01 | Allocation Code 01 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| ◉ | 00047 | 4767000 | | 0000 | 99999 | 201101 | 203512 | Customer Service Allocated C... | 00002 | 2 | 00100 |
| ○ | 00047 | 4767000 | 5211 | 4264 | 4264 | 201101 | 203512 | Labor Rel & Comp | 00002 | 2 | 00100 |
| ○ | 00047 | 4767000 | 5984 | 4263 | 4263 | 201108 | 203512 | Corporate 5984 | 00002 | 2 | 00100 |
| | *Co | *Location | *Obj Acct | *FERC Sub 1 | *FERC Sub 2 | *Start Date | Stop Date | Description | Utility Alloc Code | Utility 01 | Allocation Code 01 |
| ◉ | 00047 | 47042 | | 2870 | 29359999 | 200601 | 203512 | Pendleton District | 00002 | 2 | 00038 |
| ○ | 00047 | 47042 | | 4261 | 42659999 | 200601 | 203512 | Pendleton District-BTL | 00002 | 2 | 00038 |
| ○ | 00047 | 47042 | 4081 | 0 | 9999999 | 200601 | 203512 | Pendleton District-4081 | 00002 | 2 | 00038 |

**Allocation Code 01 Represents the code used to allocate to a Jurisdiction**
**00038 = Oregon**
**00048 = Washington**
**00100 = 3 Factor Formula (customer, employee, plant)**
**00101 = Customer Ratio**
**00102 = Employee Ratio**
**00103 = Gross Plant Ratio**

| | Co | Juris Alloc Code | Juris Start Date | Juris Stop Date | Description 10 | State 01 | Percent 01 | State 02 | Percent 02 |
|---|---|---|---|---|---|---|---|---|---|
| ◉ | 00047 | 00100 | 201501 | 201512 | 3 Factor formula -(customer, employee, plant) | OR | 24.270000 | WA | 75.730000 |
| ○ | 00047 | 00101 | 201501 | 201512 | Customer Ratio | OR | 24.940000 | WA | 75.060000 |
| ○ | 00047 | 00102 | 201501 | 201512 | Employee Ratio | OR | 25.440000 | WA | 74.560000 |
| ○ | 00047 | 00103 | 201501 | 201512 | Gross Plant Ratio | OR | 22.420000 | WA | 77.580000 |
| ○ | 00047 | 00104 | 201501 | 201512 | Rate Base Ratio | OR | 23.540000 | WA | 76.460000 |

# Exhibit I- MDUR Corporate Overhead factor

**MDU Resources Group Inc.**
**Corp Overhead Alloc Factors Jan-Jun 2017**

| | MONTANA-DAKOTA ELECTRIC | MONTANA-DAKOTA GAS DIST | CNG | IGC | TOTAL UTILITY | WBI | FIDELITY EXPLOR. & PROD. | WBI NON-REGULATED | KRC | CSG | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Corporate factor | 19.8 | 13.2 | 13.6 | 9.4 | 56.0 | 7.4 | 0.0 | 5.6 | 22.3 | 8.7 | 100.00 |

**Average Capitalization - 12 months ended 09/30/2015 for Corporate Overhead Factors Effective January 1, 2016**

| | Utility Group | WBI Energy | Knife River | Construction Services | Total |
|---|---|---|---|---|---|
| **Debt and Equity** | | | | | |
| Short-term borrowings | --- | 6,583,333.33 | --- | --- | 6,583,333.33 |
| LTD due within one year | 51,215,181.58 | 43,416,666.66 | 75,482,018.10 | 35,014,109.04 | 205,127,975.38 |
| Long-term debt | 944,553,238.29 | 265,383,037.36 | 295,332,700.51 | 75,297,579.08 | 1,580,566,555.24 |
| **Total Debt** | **995,768,419.87** | **315,383,037.35** | **370,814,718.61** | **110,311,688.12** | **1,792,277,863.95** |
| **Stockholders' equity:** | | | | | |
| Preferred stocks | 15,000,000.00 | | | | 15,000,000.00 |
| Common stock | 195,212,981.75 | | 800,000.00 | 1,000.00 | 196,013,981.75 |
| Other paid-in capital | 1,654,872,956.62 | | 489,889,551.81 | 134,623,649.93 | 2,279,386,158.36 |
| Retained earnings | 1,492,116,748.63 | | 122,708,512.63 | 93,237,371.98 | 1,708,062,633.24 |
| Accumulated other comprehensive loss | (40,262,509.76) | | (23,497,919.69) | (2,496,243.34) | (66,256,672.79) |
| Treasury stock | (3,625,812.59) | | (3,625,812.59) | --- | (7,251,625.18) |
| *Equity at WBI - Equity components provided in total* | --- | 316,551,619.60 | --- | --- | 316,551,619.60 |
| **Total common stockholders' equity** | **3,298,314,364.65** | **316,551,619.60** | **586,274,332.16** | **225,365,778.57** | **4,426,506,094.98** |
| **Total stockholders' equity** | **3,313,314,364.65** | **316,551,619.60** | **586,274,332.16** | **225,365,778.57** | **4,441,506,094.98** |
| **Total liabilities and stockholders' equity** | **4,309,082,784.52** | **631,934,656.95** | **957,089,050.77** | **335,677,466.69** | **6,233,783,958.93** |
| IC investment in subsidiaries | 2,280,176,898.63 | --- | --- | --- | 2,280,176,898.63 |
| **Capitalization** | **2,028,905,885.89** | **631,934,656.95** | **957,089,050.77** | **335,677,466.69** | **3,953,607,060.30** |
| | 51.3% | 16.0% | 24.2% | 8.5% | 100.0% |

| | 9/30/2016 Capitalization | Share of Corp. Allocation | Corporate Allocation |
|---|---|---|---|
| **Montana-Dakota** | **1,366,017** | **58.9%** | **33.0%** |
| **Cascade** | **565,055** | **24.3%** | **13.6%** |
| **Intermountain** | **389,942** | **16.8%** | **9.4%** |
| **Total Utilities Group** | **2,321,014** | **100.0%** | **56.0%** |

# Exhibit II- Cascade Allocation Factors

**Cascade Natural Gas Corportation**
**CY 2016 Allocation Factors**

Cascade Natural Gas Corporation
State Allocation Formulas
2016

| | Washington | Oregon | Total |
|---|---|---|---|
| Customers | 74.68% | 25.32% | 100.00% |
| Employees | 72.99% | 27.01% | 100.00% |
| Gross Plant | 77.45% | 22.55% | 100.00% |
| 3-Factor Formula | 75.04% | 24.96% | 100.00% |
| Rate Base Ratio | 77.16% | 22.84% | 100.00% |

Cascade Natural Gas Corporation
Average No. of Employees
2016

Source: Customers Per Employee report

| Mo-Yr | Washington District Employees (1) | Oregon District Employees (1) | |
|---|---|---|---|
| Dec-15 | 171 | 62 | |
| Jan-16 | 171 | 62 | |
| Feb-16 | 175 | 66 | |
| Mar-16 | 180 | 65 | |
| Apr-16 | 180 | 66 | |
| May-16 | 181 | 65 | |
| Jun-16 | 182 | 64 | |
| Jul-16 | 191 | 71 | |
| Aug-16 | 191 | 72 | |
| Sep-16 | 190 | 73 | |
| Oct-16 | 189 | 73 | |
| Nov-16 | 185 | 70 | |
| Dec-16 | 186 | 67 | |
| | 2,372 | 876 | |
| Average of Monthly Averages | 183 | 68 | 250 |
| Percentage | 72.99% | 27.01% | 100.00% |

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2016

| | Washington Incl. CCNC | Oregon Incl. CCNC | Total |
|---|---|---|---|
| Avg. of Mo. Avg.s | 677,494,189 | 197,221,697 | 874,715,886 |
| Percentage | 77.45% | 22.55% | 100.00% |

Cascade Natural Gas Corporation
Average Number of Customers
2016

| | Average No. of Customers | Percentage |
|---|---|---|
| Washington | 207,869 | 74.68% |
| Oregon | 70,484 | 25.32% |
| Total | 278,353 | 100.00% |

Cascade Natural Gas Corporation
Rate Base Ratio
2016

The following percentages are used for allocating interest on debt:

| | 2016 Average Rate Base | Plant Formula |
|---|---|---|
| Washington | 266,545,413 | 77.16% |
| Oregon | 78,897,061 | 22.84% |
| | 345,442,474 | 100.00% |

# Exhibit III- MDUR Shared Services Pricing Methodology

**MDU Resources Shared Services**

**Pricing Methodology - Effective for 2017**

**Note: MDU Resources' use of Shared Services** – MDU Resources costs for each shared services function is charged based 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

$ 0.50 per check for the next 500 checks

$ 0.25 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

$ 0.50 per check for the next 500 checks

$ 0.25 per check for each additional check

Additionally, there will be a $4.65 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.

**762 –Procurement Shared Services:**

Procurement Shared Services costs are invoiced based on five separate factors, all carrying an equal weight of 20%. The factors are:

- Number of Visa Cards as of 8/1/16
- Total Visa Spend for 2015
- National Account Spend for 2015
- Number of Construction Equipment Acquisitions in 2015
- Number of Fleet Acquisitions in 2015

| | MDUR | MDU | WBIE | KRC | CSG | CNG | IGC | Total |
|---|---|---|---|---|---|---|---|---|
| # VISA cards | 187 | 1,173 | 558 | 1,518 | 1,288 | 446 | 157 | 5,327 |
| % of VISA cards | 3.51% | 22.02% | 10.47% | 28.50% | 24.18% | 8.37% | 2.95% | 100% |
| VISA spend | 1,581,487 | 7,131,765 | 3,873,021 | 12,438,266 | 8,886,906 | 2,634,527 | 1,280,514 | 37,826,486 |
| % of Total VISA spend | 4.18% | 18.86% | 10.24% | 32.88% | 23.49% | 6.96% | 3.39% | 100% |
| National Account Spend | 1.891,207 | 17,506,783 | 8,234,912 | 95,811,922 | 28,575,267 | 7,336,137 | 4,365,242 | 163,721,470 |
| % of National Account Spend | 1.16% | 10.69% | 5.03% | 58.52% | 17.45% | 4.48% | 2.67% | 100% |
| | **MDUR** | **MDU** | **WBIE** | **KRC** | **CSG** | **CNG** | **IGC** | **Total** |
| # Construction Equip | 0 | 53 | 11 | 78 | 34 | 23 | 7 | 206 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Acquisitions | | | | | | | | |
| % of Construction Equip Acquisitions | 0.00% | 25.73% | 5.34% | 37.86% | 16.50% | 11.17% | 3.40% | 100% |
| # Fleet Acquisitions | 0 | 70 | 27 | 189 | 146 | 33 | 31 | 496 |
| % of Fleet Acquisitions | 0.00% | 14.12% | 5.44% | 38.10% | 29.44% | 6.65% | 6.25% | 100% |
| **Total weighted allocation factor** | 1.77% | 18.28% | 7.31% | 39.17% | 22.21% | 7.53% | 3.73% | 100.00% |

**766 –Time Entry Shared Services:**

Service provided 100% to the MDU Utility Group.

**Enterprise Technology Services (ETS):**

There are several ETS departments, and each is billed out based on its own criteria. They are as follows:

**Application Services (765)** 100% of these costs are based on the corporate factor.

**Customer Relations (965) –** The enterprise costs associated with customer relations are invoiced based upon the number of devices supported by customer relations. The metric used to determine device counts is devices that have checked into active directory during a 60 day period in the summer of 2016.

| | MDUR | MDU | WBIE | KRC | CSG | CNG | IGC | Total |
|---|---|---|---|---|---|---|---|---|
| Device Counts | 284 | 1,181 | 406 | 2,007 | 1,525 | 469 | 656 | 6,528 |
| % of Device Counts | 4.35% | 18.10% | 6.22% | 30.74% | 23.36% | 7.18% | 10.05% | 100% |
| **Totals** | 4.35% | 18.10% | 6.22% | 30.74% | 23.36% | 7.18% | 10.05% | 100% |

**Communications & Security (971)**

Enterprise charges for the communications group are invoiced using three weighted allocation factors. The factors are as follows:

1. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (40%)

2. Internet/Firewall Access – Number of user accounts (40%)

3. Security (20%)

The costs are invoiced based on the following percentages:

| | MDUR | MDU | WBIE | KRC | CSG | CNG | IGC | Total |
|---|---|---|---|---|---|---|---|---|
| WAN/LAN/MAN | 3 | 55 | 131 | 203 | 59 | 18 | 13 | 482 |
| % of Business Unit Locations | 0.62% | 11.41% | 27.18% | 42.12% | 12.24% | 3.73% | 2.70% | 100% |
| | | | | | | | | |
| Internet Access/Firewall | 284 | 1,181 | 406 | 2,007 | 1,525 | 469 | 656 | 6,528 |
| % of User Accounts | 4.35% | 18.10% | 6.22% | 30.74% | 23.36% | 7.18% | 10.05% | 100% |
| | | | | | | | | |
| Voice | 225 | 571 | 311 | 1,435 | 68 | 318 | 308 | 3,236 |
| % of Handsets | 6.95% | 17.65% | 9.61% | 44.34% | 2.10% | 9.83% | 9.52% | 100% |
| **Totals** | 3.38% | 15.34% | 15.28% | 38.01% | 14.66% | 6.33% | 7.00% | 100.00% |

**Operations (972)** – Enterprise charges for the operations group are invoiced using two separate factors. 95.9% of the costs are based upon the number of servers that are supported for a particular business unit. These servers are then broken out between full service servers and shared service servers. 4.1% of the costs are for costs specific to the AS/400 are invoiced upon the AS/400 allocation as agreed to by MDU and WBI.

The costs that are based upon the number of servers are based on the following percentages:

1. Full Service Servers- (61.49%)

2. Shared Service Servers – (38.51%)

| | MDUR | MDU | WBIE | KRC | CSG | CNG | IGC | Total |
|---|---|---|---|---|---|---|---|---|
| Full Service Servers | 305 | 152 | 35 | 103 | 31 | 0 | 0 | 626 |
| % of Full Service Servers | 48.72% | 24.29% | 5.59% | 16.45% | 4.95% | 0.00% | 0.00% | 100% |
| | | | | | | | | |
| Shared Service Servers | 18 | 97 | 39 | 52 | 73 | 34 | 79 | 392 |
| % of Full Service Servers | 4.59% | 24.75% | 9.95% | 13.27% | 18.62% | 8.67% | 20.15% | 100% |
| | | | | | | | | |
| **Totals** | 31.73% | 24.45% | 7.27% | 15.23% | 10.22% | 3.34% | 7.76% | 100% |

**Finance and Administration (982)** –. Costs for the finance and administration group are invoiced based upon the combined methodologies of the four previously identified ETS groups.

| | MDUR | MDU | WBIE | KRC | CSG | CNG | IGC | Total |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |
| % of Total Finance & Administration | 18.40% | 17.93% | 9.50% | 26.05% | 15.10% | 5.34% | 7.68% | 100% |

# Exhibit IV- Utility Operations Support Allocation Methodology

Utility Operations Support
Labor Distribution Allocation Methodology

**Leadership Group:**

- Includes Executive Vice Presidents & Directors
- Oversees all shared, utility specific functions in the following areas:
  - Customer Services
  - Administrative Services
  - Information Technology & Communications
  - Engineering and Operations Procedures
  - Gas Supply and Gas Control
- Allocation methodology:
  - Equal portion allocated to each utility company, or brand
  - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for Great Plains) to non-utility based on historical estimates, with remainder allocated to gas and electric based on meter count.
  - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocate between gas and electric based on meter count.

**Customer Services:**

- Director
  - 35% to CNG, 30% to IGC, 35% Montana-Dakota/Great Plains [1] (1% to non-utility) and remainder split between gas and electric meter count.
- Management team
  - Supervisors: Front line supervision for Customer Service Center
    - 30% to CNG, 30% to IGC, 40% Montana-Dakota/Great Plains [1] (2% to non-utility) and remainder allocated to gas and electric based on the estimate of time required to supervise
  - Manager: Customer service
    - 30% CNG, 20% IGC, 50% Montana-Dakota/Great Plains [1] (2% to non –utility) and remainder allocated to gas and electric meter count.
- Credit
  - Responsible for credit and collections for the Utility Group
  - Allocation Methodology
    - Most agents only handle credit activity for one brand, they charge all time to that brand
    - For agents that handle multiple brands, time is charged based on how much time is spent on each brand

---

[1] Based on estimated time using history

- For agents that only handle credit activity for Montana-Dakota/Great Plains:
  - Allocated to gas and electric based on meter count

  For agents that handle credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on average time spent in each utility with the Montana-Dakota/Great Plains portion allocated to gas and electric based on meter count.

- Scheduling
  - Responsible for scheduling field work for employees performing work in the field for the Utility Group
  - Responsible for emergency response 24/7
  - Allocation Methodology:
  - Management team:
    - Manager 20% IGC, 30% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
    - Team Leads 25% IGC, 25% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
    - For employees that only schedule one brand, charge time to that brand
    - For employees that schedule both IGC and CNG, split time 50/50 based on estimated time required
    - For employees who schedule all brands, split evenly
    - For employees that only schedule Montana-Dakota/Great Plains:
      - Allocated between gas and electric based on meter count
    - For employees that schedule credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on the shared utility. The Montana-Dakota/Great Plains allocation is based on the gas and electric meter count.

- Customer Service
  - Responsible for handling all inbound calls during regular operating hours
  - Allocation Methodology:
    - Teams leads and Customer Care Representatives (CCR's) when only responsible for one brand, charge all that time to one brand
    - For employees covering multiple brands, estimates are routinely made for allocations for the pay period
    - For employees responsible for Montana-Dakota/Great Plains:
      - 3% (including 0.5% for Great Plains) is charged to non-utility for credit activity associated with non-utility charges, based on best estimate of time required
      - Remainder is allocated between gas and electric based on meter count

        - For employees responsible for Montana-Dakota/Great Plains and another brand, the portion allocated to non-utility is reduced accordingly to 3% (including 0.5% for Great Plains) of the total associated with Montana-Dakota/Great Plains.

- Customer Programs & Support
    - Responsible for inbound self-service, web help, customer program transactions, and analytical support for the Utility Group
    - Allocation Methodology:
    - Manager
        - 30% IGC, 30% CNG, 40% Montana-Dakota/Great Plains[1] (allocate to gas and electric based on meter count)
            - Based on additional time for Montana-Dakota/Great Plains on social media updates & Credit Dept. responsibilities
    - Supervisor, Team Lead, and Support Staff
        - Equal portion allocated to each brand
        - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for GPNG) to non-utility, based on historical estimates, with remainder allocated to gas and electric based on meter count.
        - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocated to gas and electric based on meter count.

- Note: Exceptions may be made on an individual basis from these guidelines
    - Employees may be assigned special projects, and allocation methodology may be changed accordingly.
    - Labor allocation may always be made on an actual time spent basis rather than these guidelines.
    - Supervisors may alter these guidelines based on their individual scenario.

CASE: UG 347
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION OF OREGON

# STAFF EXHIBIT 703

## Exhibits in Support Of Opening Testimony

## September 27, 2018

Staff/703
Soldavini/1

# 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:

Report is required by: ■ OAR 860-027-0100, 860-027-0048
☐ 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(4)

List Key Words for this report. We use these to improve search results.

Affiliated Interest

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 3930 Fairview Industrial Drive SE, Salem, OR 97302.

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 31, 2016

Oregon Public Utility Commission
P.O. Box 1088
Salem, OR 97308-1088

Attn: Filing Center

RE: RG-44(4), Cascade Natural Gas Corporation's 2015 Affiliated Interest Report

Pursuant to OAR 860-027-0100, Cascade Natural Gas Corporation ("Cascade" or the "Company") submits the attached 2015 Affiliated Interest Report. In accordance with the requirements in OAR 860-027-0048(6), Attachment C to this report is the Company's Cost Allocation Manual.

Please contact me at (509) 734-4593 if you have any questions regarding this filing.

Sincerely,

Michael Parvinen
Director, Regulatory Affairs

Enclosures

# CASCADE NATURAL GAS CORPORATION

Affiliated Interest Report for the
Calendar Year 2015

**I. An Organizational chart showing the parent company, all subsidiaries, and the percentage of ownership for each.**

Please see Attachment A.

**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 Attachment B. Common directors and officers among Cascade Natural Gas Corporation, IGC, MDU, Knife River and Centennial Holdings Capital LLC are named in bold font.

**B. Changes in successive ownership between the regulated utility and the affiliated interest.**

Please see Attachment A for organizational chart for Cascade's affiliates & subsidiaries.

**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, 2015.**

Knife River Corporation is part of MDU Resources Construction Materials and Contracting. Below is the Income Statement and Balance Sheet for Construction Materials and Contracting.

| **Construction Materials and Contracting**<br>**Year ended December 31,** | **2015** |
|---|---|
| **Income statement data (Dollars in millions)** | |
| Operating revenues | $1,904.3 |
| Operating expenses: | |
| Operation and maintenance | $1,652.3 |
| Depreciation, depletion and amortization | $65.9 |
| Taxes, other than income | $40.1 |
| Total operating expenses | $1,758.3 |
| Operating income | $146.0 |
| Interest expense | $15.2 |
| Income (loss) before taxes | $130.8 |
| Income taxes | $41.6 |
| Earnings (loss) on common stock | $89.2 |

| **Construction Materials and Contracting**<br>**Year ended December 31,** | **2015** |
|---|---|
| **Balance sheet data (000's)** | |
| Property, plant and equipment | $1,553.4 |
| Less accumulated depreciation, depletion and amortization | $866.2 |
| Net property, plant and equipment | $687.2 |
| Other assets | $591.9 |
| Total identifiable assets | $1,279.1 |

**Montana-Dakota Utilities Co.**

| Year ended December 31, | 2015 |
|---|---|
| **Income statement data (000's)** | |
| Operating revenues | $541,923 |
| Operating expenses: | |
| Purchased natural gas sold | $325,231 |
| Operations | $98,776 |
| Depreciation and amortization | $46,512 |
| Taxes other Than Income | $37,553 |
| Total operating expenses | $508,072 |
| Operating income | $33,851 |
| Other income (expense) | $23,331 |
| Other Income | $9,916 |
| Income (loss) before taxes | $20,436 |
| Income taxes | $7,019 |
| Net Income | $13,417 |

| Year ended December 31, | 2015 |
|---|---|
| **Balance sheet data (000's)** | |
| Property, plant and equipment | $1,483,735 |
| Less accumulated depreciation, depletion and amortization | $(533,176) |
| Net property, plant and equipment | $950,559 |
| Other assets | $451,484 |
| Total identifiable assets | $1,402,043 |

## Centennial Holdings Capital LLC

| Year ended December 31, | 2015 |
|---|---|
| **Income statement data** | |
| Operating revenues | $9,190,965 |
| Operating expenses: | |
| Operations | $704,139 |
| Depreciation | $2,070,308.04 |
| Taxes other Than Income | $91,011 |
| Gain on Disp. Of Property | $(8,483.74) |
| Loss on Disp. Of Property | $1,927,661.55 |
| Total operating expenses | $4,784,635 |
| Operating income | $4,406,329 |
| Other income | $807,079 |
| Other Income Deductions | $236,749 |
| Income (loss) before taxes | $4,976,659 |
| Income taxes | $2,109,452 |
| Net Income | $2,867,207 |

| Year ended December 31, | 2015 |
|---|---|
| **Balance sheet data** | |
| Property, plant and equipment | $49,497,274 |
| Less accumulated depreciation, depletion and amortization | $(13,753,546) |
| Net property, plant and equipment | $ 35,743,728 |
| Other assets | $10,406,296 |
| Total identifiable assets | $46,150,024 |

## Intermountain Gas Company

| Year ended December 31, | 2015 |
|---|---|
| **Income statement data (000's)** | |
| Operating revenues | $258,368 |
| Operating expenses: | |
| Purchased natural gas sold | $168,926 |
| Operations | $45,587 |
| Depreciation and amortization | $18,829 |
| Taxes other Than Income | $10,710 |
| Total operating expenses | $244,052 |
| Operating income | $14,316 |
| Other income (expense) | $3,509 |
| Other Income | $301 |
| Income (loss) before taxes | $11,108 |
| Income taxes | $4,080 |
| Net Income | $7,028 |

| Year ended December 31, | 2015 |
|---|---|
| **Balance sheet data (000's)** | |
| Property, plant and equipment | $602,793 |
| Less accumulated depreciation, depletion and amortization | (228,488) |
| Net property, plant and equipment | 374,305 |
| Other assets | 21,702 |
| Total identifiable assets | $396,007 |

## II. Service Payments by Cascade to an Affiliate

| MDU Resources Group, Inc. | | | |
|---|---|---|---|
| **Account** | **Description** | **Total Company** | **Total Oregon** |
| | MDU/MDUR Consulting-Cap Exp | $3,502,197.73 | $849,983.39 |
| 426.1 | Donation Expense | $6,586.12 | $1,598.43 |
| 426.4 | Political Activities | $14,489.41 | $3,516.58 |
| 426.5 | Other | $213,883.08 | $51,909.43 |
| 813 | Other Gas Supply Expenses | $208,841.01 | $50,685.74 |
| 875 | Measuring & Regulating Expenses | $111,429.34 | $27,043.92 |
| 880 | Other Expense | $746,653.88 | $181,212.89 |
| 902 | Routine Meter Reading Expense | $156,601.16 | $38,007.11 |
| 903 | Customer Collection Expense | $5,609,929.57 | $1,361,530.07 |
| 909 | Informational & Instructional Advertising Expense | $19,805.30 | $4,806.73 |
| 913 | Promotional Advertising | $115.37 | $28.00 |
| 920 | Administrative & General Salaries | $3,941,952.04 | $956,711.83 |
| 921 | Office Supplies & Expenses | $1,743,769.36 | $423,212.79 |
| 922 | Administrative Expense Capitalized | ($4,522.76) | ($1,097.67) |
| 923 | Outside Services Employed | $309,592.04 | $75,137.99 |
| 925 | Injuries and Damages | $1,222.49 | $296.70 |
| 926 | Employee Pensions & Benefits | $326,605.41 | $79,267.18 |
| 930.1 | General Advertising Expenses | $18,805.33 | $4,564.05 |
| 930.2 | Misc. General Expenses | $175,232.34 | $42,528.90 |
| 931 | Rents | $1,214,385.80 | $294,731.52 |
| | **Grand Total** | **$18,317,574.02** | **$4,445,675.58** |

| Name | Description | Total Company | Total Oregon |
|---|---|---|---|
| Knife River Corporation | 931 Rent/Various Tariff Distribution | $ 94,691.77 | $ 94,691.77 |
| Centennial Holdings | 928 Injuries & Damages | $1,270,149.02 | $308,265.17 |
| Future Source Capital Corp. | 921 Office Supplies & Expenses | $13,229.80 | $3,210.87 |

| SERVICE PAYMENTS BY THE AFFILIATE TO THE UTILITY | | | |
|---|---|---|---|
| Name | Description | Total Company | Total Oregon |
| Knife River Corporation | 887 Maint. Of Mains | $ 14,814.77 | $ 14,814.77 |
| Intermountain Gas Co. | 24/7 gas control monitoring | $791,525.71 | $192,103.29 |
| Montana Dakota Utilities Co. | 24/7 gas control monitoring | $782,625.63 | $189,943.24 |

**Descriptions of Basis Pricing**
Attachment C 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 2015, and no Affiliate loaned Cascade money in 2015.

**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.

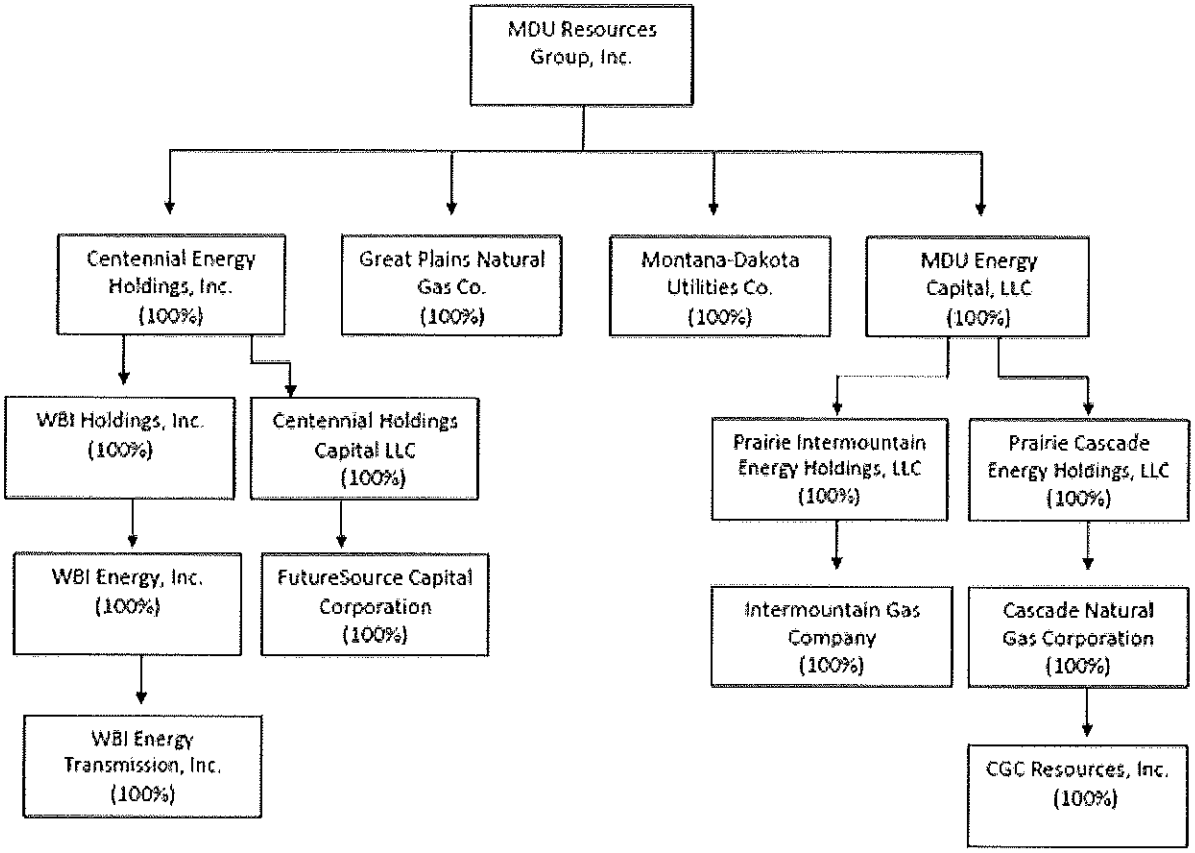
**IV. Parent guaranteed debt of affiliate**
None.

**V. Transactions other than services**
None.

# Attachments

## ATTACHMENT A

**Subsidiaries of MDU Resources Group, Inc.**
**Effective Date: 2/11/2016**
**Created Date: 2/11/2016**




*The percentages under each company's name refer to MDURs interest in each

**ATTACHMENT B**

| CASCADE NATURAL GAS CORPORATION | | |
|---|---|---|
| Directors | **David L. Goodin** | |
| | Nicole A. Kivisto | |
| | **Daniel S. Kuntz** | |
| | Doran N. Schwartz | |
| Officers | **David L. Goodin** | **Chairman of the Board** |
| | Garret Senger | Executive Vice President, Regulatory Affairs, Customer Service and Gas Supply |
| | Mark A. Chiles | Vice President, Regulatory Affairs and Customer Service |
| | Julie A. Krenz | Assistant Secretary |
| | **Daniel S. Kuntz** | **General Counsel and Secretary** |
| | Scott W. Madison | Executive Vice President, Western Region Operations, Business Development and Strategy |
| | Jason L. Vollmer | Treasurer |
| | Eric P. Martuscelli | Vice President, Operations |
| | Nicole A. Kivisto | President and Chief Executive Officer |
| | Margaret A. Link | Chief Information Officer |
| | Ann M. Jones | Vice President, Human Resources |
| | Karl A. Liepitz | Assistant Secretary |
| **KNIFE RIVER CORPORATION** | | |
| Directors | David C. Barney | |
| | **David L. Goodin** | |
| | Doran N. Schwartz | |
| | **Daniel S. Kuntz** | |
| Officers | David C. Barney | President and Chief Executive Officer |
| | Nancy K Christenson | Vice President, Administration and Treasurer |
| | Christopher B. Ford | Chief Accounting Officer |
| | **David L. Goodin** | Chairman of the Board |
| | Trevor J. Hastings | Vice President, Business Development and Operations Support |
| | **Daniel S. Kuntz** | **General Counsel and Secretary** |
| | Karl A. Liepitz | Assistant Sectretary |

**ATTACHMENT B (continued)**

| INTERMOUNTAIN GAS COMPANY | | |
|---|---|---|
| Directors | **David L. Goodin** | |
| | **Nicole A. Kivisto** | |
| | **Daniel S. Kuntz** | |
| | Doran N. Schwartz | |
| Officers | **David L. Goodin** | **Chairman of the Board** |
| | Garret Senger | Executive Vice President, Regulatory Affairs, Customer Service and Gas Supply |
| | Mark A. Chiles | Vice President, Regulatory Affairs and Customer Service |
| | Julie A. Krenz | Assistant Secretary |
| | **Daniel S. Kuntz** | **General Counsel and Secretary** |
| | Scott W. Madison | Executive Vice President, Western Region Operations, Business Development and Strategy |
| | Jason L. Vollmer | Treasurer |
| | Hart Gilchrist | Vice President, Operations |
| | **Nicole A. Kivisto** | **President and Chief Executive Officer** |
| | Margaret A. Link | Chief Information Officer |
| | Ann M. Jones | Vice President, Human Resources |
| | Karl A. Liepitz | Assistant Secretary |
| **MONTANA-DAKOTA UTILITIES CO.** | | |
| Members | **David L. Goodin** | |
| | **Nicole A. Kivisto** | |
| | **Daniel S. Kuntz** | |
| | Doran N. Schwartz | |
| Officers | Patrick C. Darras | Vice President, Operations |
| | Kristi B. Hourigan | Assistant Secretary |
| | **Daniel S. Kuntz** | **General Counsel and Secretary** |
| | Ann M. Jones | Vice President, Human Resources |
| | **Nicole A. Kivisto** | **President and Chief Executive Officer** |

| ATTACHMENT B | | |
|---|---|---|
| **MONTANA-DAKOTA UTILITIES CO (CONTINUED)** | | |
| | Margaret A. Link | Chief Information Officer |
| | Garret Senger | Executive Vice President, Regulatory Affairs, Customer Service and Gas Supply |
| | Mark A. Chiles | Vice President, Regulatory Affairs and Customer Service |
| | Julie A. Krenz | Assistant Secretary |
| | Karl A. Liepitz | Assistant Secretary |
| | Jay Skabo | Vice President, Electric Supply |
| | Scott W. Madison | Executive Vice President, Western Region Operations, Business Development and Strategy |
| **CENTENNIAL HOLDINGS CAPITAL LLC** | | |
| Managers | **Doran N. Schwartz** | |
| | **David L. Goodin** | |
| | **Daniel S. Kuntz** | |
| Officers | Alvin J. Feist | Vice President and Treasurer |
| | **David L. Goodin** | **Chairman of the Board** |
| | **Daniel S. Kuntz** | **General Counsel and Secretary** |
| | **Doran N. Schwartz** | **President and Chief Executive Officer** |
| | Jason L. Vollmer | Assistant Secretary |
| **FUTURESOURCE CAPITAL CORP.** | | |
| Directors | **Doran N. Schwartz** | |
| | **David L. Goodin** | |
| | **Daniel S. Kuntz** | |
| Officers | Alvin J. Feist | Vice President and Treasurer |
| | **David L. Goodin** | **Chairman of the Board** |
| | **Daniel S. Kuntz** | **General Counsel and Secretary** |
| | **Doran N. Schwartz** | **President and Chief Executive Officer** |
| | Jason L. Vollmer | Assistant Treasurer |
| | Julie A. Krenz | Assistant Secretary |

# Cascade Natural Gas

## Cost Allocation Manual
## 2015

CASCADE NATURAL GAS CORPORATION®

A Subsidiary of MDU Resources Group, Inc.

*In the Community to Serve®*

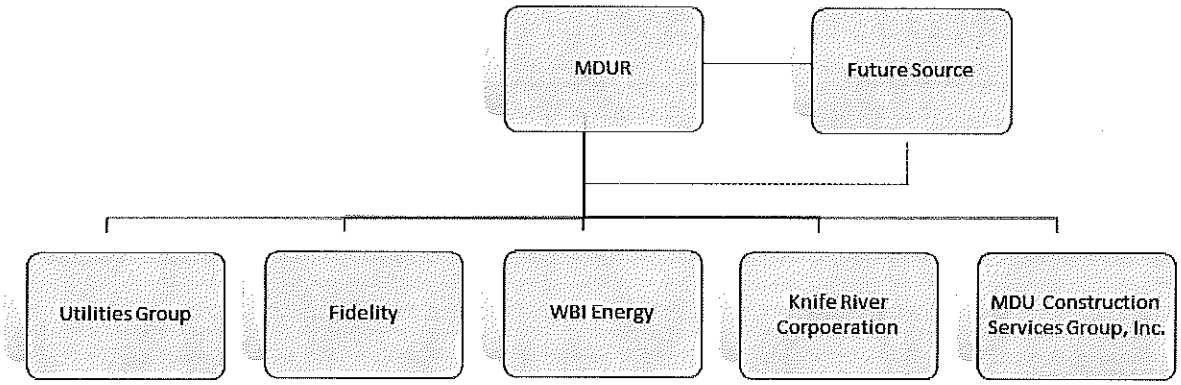
# Table of Contents

Overview

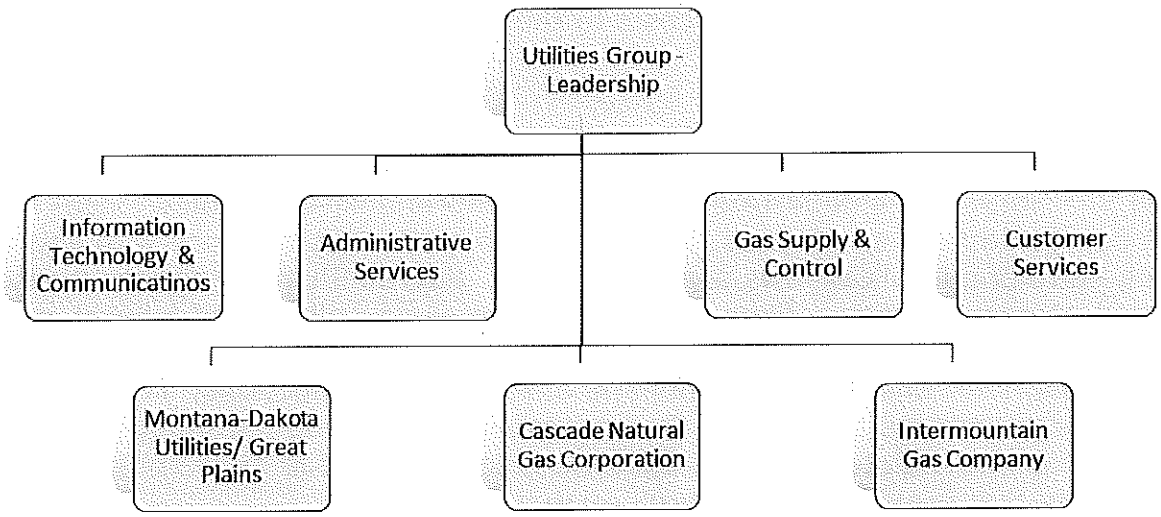
Cascade Natural Gas Corporation (Cascade), a subsidiary of MDU Resources Group, Inc. (MDUR), conducts business in two states with regulated gas distribution operations.

Below is an overview of the operational structure for the purpose of assigning costs. The diagrams presented are intended to provide an overview for cost allocation only and are 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.)

# Corporate Level



# Utility Group Level




This document is intended to provide an overview of the different types of allocations and the processes employed to direct costs to the proper utility and state jurisdiction for Cascade.

This document will discuss the allocations from:

- MDUR and FutureSource to Cascade Natural Gas
- Montana-Dakota/Great Plains (MDU) and Intermountain Gas Company (IGC) to Cascade Natural Gas
- Cascade to MDU and IGC
- 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, procurement and enterprise 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 III)

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 Cascade, the payroll shared services department is also responsible for the accumulation of time entry records and maintenance of employee records. Cascade does not have any departments that provide these payroll related services.

**Procurement Shared Services**

Procurement Shared Services 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 of the Corporation's operating companies. National accounts, or preferred vendor agreements, typically are negotiated at the corporate level rather than at the local company level. Procurement Shared Services also is responsible for monitoring the level of services, quantities, discounts and rebates associated with established national accounts. Cascade has a single procurement department that places specific purchase requests for materials and services required to conduct business with approved vendors.

**Enterprise Technology Service**

Enterprise Technology Services (ETS) provides policy guidance, infrastructure related IT functions and security-focused governance. ETS seeks to increase the return on investment in technology through consolidation of common IT systems and services, while eliminating waste and duplication. ETS 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.

Cascade's IT department consists of Montana-Dakota/Great Plains employees physically located in Kennewick, Washington, Boise, Idaho, and Bismarck, North Dakota. This Department is responsible for supporting applications specific to the

utility group such as the Customer Care & Billing System, the JD Edwards financial software, Scada and mobile applications, Enterprise GIS, and PowerPlan which is the project and fixed asset accounting software. In addition the utility group IT department develops business continuity plans in the case of disaster recovery.

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
- Travel
- Treasury services

Cascade receives an allocation of these corporate costs. Corporate Policy No. 50.9 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. 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 is reflected as CNGC 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)
- Fidelity

- WBI Energy Transmission
- WBI Midstream
- Knife River (KR)
- MDU Construction Services Group, Inc.

The corporate costs allocated to Cascade are subsequently allocated to the state jurisdictions. Corporate costs are recorded in the administrative and general (A&G) function for Cascade. (See state jurisdictional allocation discussion on page 8.)

Montana-Dakota/Great Plains 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. The costs are allocated based on the number of customers served by each utility.

Intermountain Gas owns the customer care center located in Meridian, ID. To cover the cost of ownership and operating costs associated with that owned asset, a revenue requirement (asset return plus annual operating expenses) is computed similarly to Montana-Dakota owned 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 Montana-Dakota/Great Plains and Cascade as a monthly fee. The costs are allocated based on the number of customers served by each utility.

Certain Cascade owned assets, such as the portion of the General Office facility used for Shared Services (i.e. Gas Control, IT), located at the utility headquarters in Kennewick, 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 MDU and IGC, as a monthly fee. The costs are allocated based on the number of customers served by each utility.

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)
- Information Technology and Communications- (Management Information Systems, Technology and Compliance)
- Administrative Services - (Procurement, Office Services, Fleet Operations)
- Gas Supply & Control

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 IV.

Standard Labor Distributions

Labor/Reimbursable expense allocations

The development of standard labor distributions for Cascade 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 jurisdiction where possible. If the expense is not direct, the appropriate jurisdiction is charged as follows:

**Union Employees**

Time tickets are required for productive time. The employee specifies the proper 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.

**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 based on an

expected ratio of work. 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 periodically.

Cascade Allocations to State Jurisdictions

Cascade 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. The allocation process creates a Journal Entry to the JD Edwards jurisdictional ledgers established by state.

The allocation methodology is as follows:

The JD Edwards (JDE) software is used by Cascade 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:

Business Unit - 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 (i.e. gas regulator station), or department (i.e. human resources, engineering).

Object – 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.

Subsidiary – The subsidiary portion of the account for O&M accounts identifies the utility segment (2 represents gas) 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.

Revenue Accounts – Revenues are directly assigned to the jurisdiction when possible. The applicable FERC account is part of the account structure. It is the combination of the business unit, 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), 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) 47041 represents the geographic location of the Bend, Oregon District. The Bend District is therefore directly assigned to Oregon for all FERC accounts.

Another example is location 4767000, representing the Credit and Collections Department. The allocation of costs is based on the FERC range of accounts. The location may also be a responsibility, or department. An allocation code is used to split the costs between the states. The most common allocation factor is the 3-factor formula (customer, employee and plant). However, the customer ratio, employee ratio, gross plant ratio, and rate base ratio are also used. See Exhibit II for the allocation factor calculations.

| *Co | *Location | *Obj Acct | *FERC Sub 1 | *FERC Sub 2 | *Start Date | Stop Date | Description | Utility Alloc Code | Utility 01 | Allocation Code 01 |
|---|---|---|---|---|---|---|---|---|---|---|
| 00047 | 47041 | | 2870 | 29359999 | 200601 | 203512 | Central OR District | 00002 | 2 | 00038 |
| 00047 | 47041 | | 4261 | 42659999 | 201208 | 203512 | Bend District-BTL | 00002 | 2 | 00038 |
| 00047 | 47041 | 4081 | 0 | 99999999 | 200601 | 203512 | Central OR District-4081 | 00002 | 2 | 00038 |
| 00047 | 47041 | 5981 | 4261 | 4261 | 200902 | 201207 | Central OR District | 00002 | 2 | 00038 |
| 00047 | 47041 | 5984 | 4263 | 4263 | 201111 | 201207 | OR 5984 | 00002 | 2 | 00038 |

**Code 00038 = 100% allocated to Oregon**

| *Co | *Location | *Obj Acct | *FERC Sub 1 | *FERC Sub 2 | *Start Date | Stop Date | Description | Utility Alloc Code | Utility 01 | Allocation Code 01 |
|---|---|---|---|---|---|---|---|---|---|---|
| 00047 | 4767000 | | 0000 | 99999 | 201101 | 203512 | Customer Service Allocated C... | 00002 | 2 | 00100 |
| 00047 | 4767000 | 5211 | 4264 | 4264 | 201101 | 203512 | Labor Rel & Comp | 00002 | 2 | 00100 |
| 00047 | 4767000 | 5984 | 4263 | 4263 | 201108 | 203512 | Corporate 5984 | 00002 | 2 | 00100 |

| *Co | *Location | *Obj Acct | *FERC Sub 1 | *FERC Sub 2 | *Start Date | Stop Date | Description | Utility Alloc Code | Utility 01 | Allocation Code 01 |
|---|---|---|---|---|---|---|---|---|---|---|
| 00047 | 47042 | | 2870 | 29359999 | 200601 | 203512 | Pendleton District | 00002 | 2 | 00038 |
| 00047 | 47042 | | 4261 | 42659999 | 200601 | 203512 | Pendleton District-BTL | 00002 | 2 | 00038 |
| 00047 | 47042 | 4081 | 0 | 9999999 | 200601 | 203512 | Pendleton District-4081 | 00002 | 2 | 00038 |

**Allocation Code 01 Represents the code used to allocate to a Jurisdiction**
**00038 = Oregon**
**00048 = Washington**
**00100 = 3 Factor Formula (customer, employee, plant)**
**00101 = Customer Ratio**
**00102 = Employee Ratio**
**00103 = Gross Plant Ratio**

| Co | Juris Alloc Code | Juris Start Date | Juris Stop Date | Description 10 | State 01 | Percent 01 | State 02 | Percent 02 |
|---|---|---|---|---|---|---|---|---|
| 00047 | 00100 | 201501 | 201512 | 3 Factor formula -(customer, employee, plant) | OR | 24.270000 | WA | 75.730000 |
| 00047 | 00101 | 201501 | 201512 | Customer Ratio | OR | 24.940000 | WA | 75.060000 |
| 00047 | 00102 | 201501 | 201512 | Employee Ratio | OR | 25.440000 | WA | 74.560000 |
| 00047 | 00103 | 201501 | 201512 | Gross Plant Ratio | OR | 22.420000 | WA | 77.580000 |
| 00047 | 00104 | 201501 | 201512 | Rate Base Ratio | OR | 23.540000 | WA | 76.460000 |

Exhibit I- MDUR Corporate Overhead factor

MDU Resources Group Inc.
Corporate Overhead Allocation Factors
**January- June 2015**

| | MDU Electric | MDU/GP Gas | CNGC | IGC | WBI Energy | Fidelity | WBI Non-Regulated | KR | CSG |
|---|---|---|---|---|---|---|---|---|---|
| MDUR corporate factor | 10.6% | 7.9% | 10.4% | 6.9% | 5.6% | 26.9% | 4.9% | 20.2% | 6.6% |

| | Utilities Group | WBI Holdings Transmission | WBI Holdings Fidelity | WBI Holdings Other | Knife River | Construction Services | Total |
|---|---|---|---|---|---|---|---|
| **Debt and Equity** | | | | | | | |
| Short-term borrowings | $4,725,000 | | | | | | $4,725,000 |
| LTD due within one year | 17,881,342 | $1,266,056 | $6,120,496 | $1,110,555 | $14,749,607 | $5,013,969 | 46,142,025 |
| Long-term debt | 820,826,670 | 119,857,876 | 579,428,942 | 105,136,553 | 364,144,141 | 76,620,712 | 2,066,014,894 |
| **Total Debt** | 843,433,012 | 121,123,932 | 585,549,438 | 106,247,108 | 378,893,748 | 81,634,681 | 2,116,881,919 |
| **Stockholders' equity:** | | | | | | | |
| Preferred stock | 15,000,000 | | | | | | 15,000,000 |
| Common stock | 191,925,108 | 149 | 720 | 131 | 800,000 | 1,000 | 192,727,108 |
| Other paid-in capital | 1,521,081,527 | 97,970,621 | 473,619,385 | 85,937,560 | 485,948,676 | 134,430,866 | 2,798,988,636 |
| Retained earnings | 1,674,807,588 | 56,537,562 | 273,319,542 | 49,593,440 | 149,530,017 | 110,166,923 | 2,313,955,072 |
| Accumulated other comprehensive loss | (40,827,124) | (2,185,717) | (10,566,414) | (1,917,261) | (19,404,583) | (2,153,395) | (77,054,494) |
| Treasury stock | (3,625,813) | | | | | | (3,625,813) |
| **Total common stockholders' equity** | 3,343,361,287 | 152,322,614 | 736,373,233 | 133,613,870 | 616,874,110 | 242,445,394 | 5,224,990,509 |
| **Total stockholders' equity** | 3,358,361,287 | 152,322,614 | 736,373,233 | 133,613,870 | 616,874,110 | 242,445,394 | 5,239,990,509 |
| **Total liabilities and stockholders' equity** | 4,201,794,299 | 273,446,546 | 1,321,922,671 | 239,860,979 | 995,767,858 | 324,080,075 | 7,356,872,429 |
| Investment in Subsidiaries | 2,447,121,024 | | | | | | 2,447,121,024 |
| **Capitalization** | $1,754,673,276 | $273,446,546 | $1,321,922,671 | $239,860,979 | $995,767,858 | $324,080,075 | $4,909,751,405 |
| | 35.8% | 5.6% | 26.9% | 4.9% | 20.2% | 6.6% | 100.0% |

| | 2014 Year End Capitalization | Share of Corp. Allocation | Corporate Allocation | Electric | Gas |
|---|---|---|---|---|---|
| Montana-Dakota 1/ | $952,540 | 51.7% | 18.5% | 10.6% | 7.9% |
| Cascade | 537,073 | 29.1% | 10.4% | | 10.4% |
| Intermountain | 353,195 | 19.2% | 6.9% | | 6.9% |
| Total Utilities Group | $1,842,808 | 100.0% | 35.8% | 10.6% | 25.2% |

1/ Electric and gas segments allocated on Montana-Dakota's Corporate Overhead Factor

# Exhibit II- Cascade Allocation Factors

**Cascade Natural Gas Corportation**
**CY 2014 Allocation Factors**

Cascade Natural Gas Corporation
State Allocation Formulas
2014

| | Washington | Oregon | Total |
|---|---|---|---|
| Customers | 75.06% | 24.94% | 100.00% |
| Employees | 74.56% | 25.44% | 100.00% |
| Gross Plant | 77.58% | 22.42% | 100.00% |
| 3-Factor Formula | 75.73% | 24.27% | 100.00% |
| Rate Base Ratio | 76.46% | 23.54% | 100.00% |

Cascade Natural Gas Corporation
Average No. of Employees
2014

Source: Customers Per Employee ref

| Mo-Yr | Washington District Employees (1) | Oregon District Employees (1) |
|---|---|---|
| Dec-13 | 154 | 56 |
| Jan-14 | 165 | 56 |
| Feb-14 | 165 | 56 |
| Mar-14 | 166 | 56 |
| Apr-14 | 166 | 57 |
| May-14 | 170 | 57 |
| Jun-14 | 174 | 58 |
| Jul-14 | 174 | 60 |
| Aug-14 | 169 | 57 |
| Sep-14 | 172 | 59 |
| Oct-14 | 167 | 59 |
| Nov-14 | 168 | 59 |
| Dec-14 | 169 | 55 |
| | 2,179 | 744 |
| Average of Monthly Averages | 168 | 57 | 226 |
| Percentage | 74.56% | 25.44% | 100.00% |

(1) Excludes Interstate employees

Cascade Natural Gas Corporation
Gross Plant Percentage
2014

| | Washington Incl. CCNC | Oregon Incl. CCNC | Total |
|---|---|---|---|
| Avg. of Mo. Avg.s | 607,126,362 | 175,487,064 | 782,613,426 |
| Percentage | 77.58% | 22.42% | 100.00% |

Cascade Natural Gas Corporation
Average Number of Customers
2014

| | Average No. of Customers | Percentage |
|---|---|---|
| Washington | 202,195 | 75.06% |
| Oregon | 67,182 | 24.94% |
| Total | 269,377 | 100.00% |

Cascade Natural Gas Corporation
Rate Base Ratio
2014

The following percentages are used for allocating interest on debt:

| | 2014 Average Rate Base | Plant Formula |
|---|---|---|
| Washington | 228,079,689 | 76.46% |
| Oregon | 70,217,372 | 23.54% |
| | 298,297,061 | 100.00% |

# Exhibit III- MDUR Shared Services Pricing Methodology

**MDU Resources Shared Services**
**Pricing Methodology - Effective for 2015**

**Note: MDU Resources' use of Shared Services** – MDU Resources costs for each shared services function is charged based 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 paycard 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
$ 0.75 per check for the next 500 checks
$ 0.00 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 1000 checks
$ 0.75 per check for the next 1000 checks
$ 0.00 per check for each additional check

Additionally, there will be a $3.00 charge for each tax payment and $240.00 charge for each quarterly tax filing

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.

**762 – Procurement Shared Services:**
Procurement Shared Services costs are invoiced based on five separate factors, all carrying an equal weight of 20%. The factors are:

- Number of Visa Cards as of 8/1/14
- Total Visa Spend for 2013
- National Account Spend for 2013
- Number of Construction Equipment Acquisitions in 2013
- Number of Fleet Acquisitions in 2013

| | MDUR | MDU | WBIE | FEPC | KRC | CSG | CNG | IMG | Total |
|---|---|---|---|---|---|---|---|---|---|
| # VISA cards | 141 | 805 | 364 | 155 | 845 | 658 | 282 | 88 | 3,339 |
| % of VISA cards | 4.22% | 24.11% | 10.90% | 4.64% | 25.31% | 19.74% | 8.45% | 2.64% | 100% |
| VISA spend | 2,158,498 | 6,589,113 | 3,337,060 | 1,464,510 | 9,190,014 | 7,644,519 | 2,984,759 | 1,567,358 | 34,935,930 |
| % of Total VISA spend | 6.18% | 18.86% | 9.55% | 4.19% | 26.31% | 21.88% | 8.54% | 4.49% | 100% |
| National Account Spend | 2,026,585 | 3,244,617 | 1,831,527 | 79,372 | 20,683,247 | 13,945,478 | 1,255,335 | 888,731 | 43,954,891 |
| % of National Account Spend | 4.61% | 7.38% | 4.17% | 0.18% | 47.05% | 31.73% | 2.86% | 2.02% | 100% |

| | MDUR | MDU | WBIE | FEPC | KRC | CSG | CNG | IMG | Total |
|---|---|---|---|---|---|---|---|---|---|
| # Construction Equip Acquisitions | 0 | 55 | 8 | 2 | 87 | 40 | 14 | 7 | 213 |
| % of Construction Equip Acquisitions | 0.00% | 25.82% | 3.76% | 0.94% | 40.85% | 18.78% | 6.57% | 3.29% | 100% |
| # Fleet Acquisitions | 0 | 43 | 35 | 11 | 189 | 232 | 43 | 19 | 572 |
| % of Fleet Acquisitions | 0.00% | 7.52% | 6.12% | 1.92% | 33.04% | 40.56% | 7.52% | 3.32% | 100% |
| Total weighted allocation factor | 3.00% | 16.74% | 6.90% | 2.37% | 34.51% | 26.54% | 6.79% | 3.15% | 100.00% |

**766 –Time Entry Shared Services:**

Service provided 100% to the MDU Utility Group.

**767 –Accounts Payable Shared Services:**

Accounts Payable Shared Services costs are invoiced based on three factors:

- Number of payments processed based on activity from 7/1/13 through 6/30/14 (25%)
- Number of vouchers processed by AP Shared Services staff based on activity from 7/1/13 through 6/30/14 (75%)

| | MDUR | MDU | WBIE | FEPC | KRC | CSG | CNG | IGC | Total |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | |
| # of Payments | 2556 | 52880 | 0 | 0 | 0 | 1522 | 27126 | 26222 | 110,306 |
| % of payments | 2.32% | 47.94% | 0.00% | 0.00% | 0.00% | 1.38% | 24.59% | 23.77% | 100% |
| | | | | | | | | | |
| # of Vouchers | 3,046 | 11,879 | 0 | 0 | 0 | 1,389 | 1,333 | 1,246 | 18,893 |
| % of vouchers | 16.12% | 62.88% | 0.00% | 0.00% | 0.00% | 7.35% | 7.06% | 6.60% | 100% |
| | | | | | | | | | |
| Totals | 12.7% | 59.1% | 0.0% | 0.0% | 0.0% | 5.9% | 11.4% | 10.9% | 100.00% |

## Enterprise Technology Services (ETS):

There are several ETS departments, and each is billed out based on its own criteria. They are as follows:

**Application Services (765)** 100% of these costs are based on the corporate factor.

**Customer Relations (965)** – Two factors are used in the invoicing of the enterprise costs associated with customer relations. 85.8% of the costs are associated with the help desk. Those costs are invoiced based upon the number of devices supported by customer relations. The metric used to determine device counts is devices that have checked into active directory during a 60 day period in the summer of 2014. The remaining 14.2% of the costs are for costs specific to the AS/400 are invoiced upon the AS/400 allocation as agreed to by MDU and WBI.

| | MDUR | MDU | WBIE | FEPC | KRC | CSG | CNG | IMG | Total |
|---|---|---|---|---|---|---|---|---|---|
| Device Counts | 287 | 1,080 | 460 | 313 | 1,820 | 1305 | 432 | 626 | 6,323 |
| | | | | | | | | | |
| % of Device Counts | 4.54% | 17.08% | 7.28% | 4.95% | 28.78% | 20.64% | 6.83% | 9.90% | 100% |
| Totals | 4.54% | 17.08% | 7.28% | 4.95% | 28.78% | 20.64% | 6.83% | 9.90% | 100.00% |

**Communications & Security (971)** – Now includes 977.

Enterprise charges for the communications group are invoiced using three separate factors. They and their estimated % of work are:

1. Wide Area Network/Local Area Network/Metropolitan Area Network- Number of business unit locations (20%)
2. Internet/Security – Number of user accounts (30%)
3. Handsets – Number of IP devices(50%)

Each of these three areas is assigned a percentage (identified above). Those portions of the costs are invoiced via the above identified denominators.

For 2014 the costs are invoiced based on the following percentages:

| | MDUR | MDU | WBIE | FEPC | KRC | CSG | CNG | IMG | Total |
|---|---|---|---|---|---|---|---|---|---|
| WAN/LAN/MAN | 2 | 40 | 100 | 8 | 190 | 59 | 18 | 13 | 430 |
| % of Business Unit Locations | 0.47% | 9.30% | 23.26% | 1.86% | 44.19% | 13.72% | 4.19% | 3.02% | 100% |
| | | | | | | | | | |
| Internet Access/Firewall | 287 | 1080 | 460 | 313 | 1820 | 1305 | 432 | 626 | 6323 |
| % of User Accounts | 4.54% | 17.08% | 7.28% | 4.95% | 28.78% | 20.64% | 6.83% | 9.90% | 100% |
| | | | | | | | | | |
| Security | | | | | | | | | |
| % of Handsets | 16.50% | 16.70% | 16.70% | 16.70% | 16.70% | 16.70% | 0.00% | 0.00% | 100% |
| | | | | | | | | | |
| **Totals** | 9.70% | 15.33% | 15.19% | 10.21% | 25.82% | 17.29% | 2.89% | 3.57% | 100.00% |

**Operations (972)** – Enterprise costs for the operations group are invoiced based upon the number of servers that are supported for a particular business unit.

For 2014 the costs are invoiced based on the following percentages:

| | MDUR | MDU | WBIE | FEPC | KRC | CSG | CNG | IMG | Total |
|---|---|---|---|---|---|---|---|---|---|
| Full Service Servers | 178 | 147 | 85 | 64 | 196 | 104 | 33 | 90 | 897 |
| % of Full Service Servers | 19.84% | 16.39% | 9.48% | 7.13% | 21.85% | 11.59% | 3.68% | 10.03% | 100% |
| | | | | | | | | | |
| **Totals** | 19.84% | 16.39% | 9.48% | 7.13% | 21.85% | 11.59% | 3.68% | 10.03% | 100% |

**Security (977)** – This is now included in 971.

**Finance and Administration (982)** –. Costs for the finance and administration group are invoiced based upon the combined methodologies of the four previously identified ETS groups.

| | MDUR | MDU | WBIE | FEPC | KRC | CSG | CNG | IMG | Total |
|---|---|---|---|---|---|---|---|---|---|
| % of Total Finance & Administration | 21.32% | 14.35% | 11.24 % | 7.29% | 22.70% | 13.78% | 3.49% | 5.83% | 100% |

# Exhibit IV- Utility Operations Support Allocation Methodology

Utility Operations Support

Labor Distribution Allocation Methodology

**Leadership Group:**

- Includes Executive Vice Presidents & Directors
- Oversees all shared, utility specific functions in the following areas:
  - Customer Services
  - Administrative Services
  - Information Technology & Communications
  - Engineering and Operations Procedures
  - Gas Supply and Gas Control
- Allocation methodology:
  - Equal portion allocated to each utility company, or brand
  - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for Great Plains) to non-utility based on historical estimates, with remainder allocated to gas and electric based on meter count.
  - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocate between gas and electric based on meter count.

**Customer Services:**

- Director
  - 35% to CNG, 30% to IGC, 35% Montana-Dakota/Great Plains [1] (1% to non-utility) and remainder split between gas and electric meter count.
- Management team
  - Supervisors: Front line supervision for Customer Service Center
    - 30% to CNG, 30% to IGC, 40% Montana-Dakota/Great Plains [1] (2% to non-utility) and remainder allocated to gas and electric based on the estimate of time required to supervise
  - Manager: Customer service
    - 30% CNG, 20% IGC, 50% Montana-Dakota/Great Plains [1] (2% to non –utility) and remainder allocated to gas and electric meter count.
- Credit
  - Responsible for credit and collections for the Utility Group
  - Allocation Methodology
    - Most agents only handle credit activity for one brand, they charge all time to that brand
    - For agents that handle multiple brands, time is charged based on how much time is spent on each brand

---

[1] Based on estimated time using history

- For agents that only handle credit activity for Montana-Dakota/Great Plains:
  - Allocated to gas and electric based on meter count

  For agents that handle credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on average time spent in each utility with the Montana-Dakota/Great Plains portion allocated to gas and electric based on meter count.

- Scheduling
  - Responsible for scheduling field work for employees performing work in the field for the Utility Group
  - Responsible for emergency response 24/7
  - Allocation Methodology:
  - Management team:
    - Manager 20% IGC, 30% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
    - Team Leads 25% IGC, 25% CNG, 50% Montana-Dakota/Great Plains[1] allocated to gas and electric based on meter count.
    - For employees that only schedule one brand, charge time to that brand
    - For employees that schedule both IGC and CNG, split time 50/50 based on estimated time required
    - For employees who schedule all brands, split evenly
    - For employees that only schedule Montana-Dakota/Great Plains:
      - Allocated between gas and electric based on meter count
    - For employees that schedule credit for Montana-Dakota/Great Plains and another brand, the portion is allocated to each utility based on the shared utility. The Montana-Dakota/Great Plains allocation is based on the gas and electric meter count.

- Customer Service
  - Responsible for handling all inbound calls during regular operating hours
  - Allocation Methodology:
    - Teams leads and Customer Care Representatives (CCR's) when only responsible for one brand, charge all that time to one brand
    - For employees covering multiple brands, estimates are routinely made for allocations for the pay period
    - For employees responsible for Montana-Dakota/Great Plains:
      - 3% (including 0.5% for Great Plains) is charged to non-utility for credit activity associated with non-utility charges, based on best estimate of time required
      - Remainder is allocated between gas and electric based on meter count

        - For employees responsible for Montana-Dakota/Great Plains and another brand, the portion allocated to non-utility is reduced accordingly to 3% (including 0.5% for Great Plains) of the total associated with Montana-Dakota/Great Plains.

- Customer Programs & Support
    - Responsible for inbound self-service, web help, customer program transactions, and analytical support for the Utility Group
    - Allocation Methodology:
    - Manager
        - 30% IGC, 30% CNG, 40% Montana-Dakota/Great Plains[1] (allocate to gas and electric based on meter count)
            - Based on additional time for Montana-Dakota/Great Plains on social media updates & Credit Dept. responsibilities
    - Supervisor, Team Lead, and Support Staff
        - Equal portion allocated to each brand
        - For portion allocated to Montana-Dakota/Great Plains, if there is involvement with non-utility work allocate 1% (including 0.25% for GPNG) to non-utility, based on historical estimates, with remainder allocated to gas and electric based on meter count.
        - For portion allocated to Montana-Dakota/Great Plains, if there is no involvement with non-utility work, allocated to gas and electric based on meter count.

- Note: Exceptions may be made on an individual basis from these guidelines
    - Employees may be assigned special projects, and allocation methodology may be changed accordingly.
    - Labor allocation may always be made on an actual time spent basis rather than these guidelines.
    - Supervisors may alter these guidelines based on their individual scenario.

CASE: UG 347
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 704

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

**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 347
WITNESS: SABRINNA SOLDAVINI

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 705

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## Standard Data Requests

**Request No. 119**

Date prepared: 3/21/2018

Preparer: Pamela Archer

Contact: Pamela Archer

Telephone: (509)-734-4591

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 OPUC-119.xlsx

**Cascade Natural Gas Corportation**
**CY 2017 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 | 721,672,786 | 209,695,352 | 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

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. | 210,796 | 71,933 | 282,729 |
| Feb. | 210,983 | 72,009 | 282,992 |
| Mar. | 211,065 | 72,057 | 283,122 |
| Apr. | 211,041 | 72,101 | 283,142 |
| May | 210,636 | 72,001 | 282,637 |
| June | 210,111 | 71,882 | 281,993 |
| July | 209,873 | 71,847 | 281,720 |
| Aug. | 209,751 | 71,902 | 281,653 |
| Sept. | 210,539 | 72,266 | 282,805 |
| Oct. | 212,041 | 72,811 | 284,852 |
| Nov. | 213,194 | 73,260 | 286,454 |
| Dec. | 213,945 | 73,582 | 287,527 |
| Average | 211,165 | 72,304 | |

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

Due Date: August 31, 2018

**Request No. 287**

Date prepared: 8/30/2018

Preparer: Mark Chiles/Kevin Conwell

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 287**

Please refer to the file produced in response to OPUC DR 164 "OPUC-164 CNG Cost Allocation Manual 2017". Please refer to pages 19-21 of this file, "Exhibit IV".

a. Please provide the Cascade allocation factor for the "Leadership Group" expenses. Please explain in narrative form the appropriateness of allocating an equal portion to each utility company, or brand and please provide any documentation supporting said explanation.
b. Cascade appears to be assigned an allocation factor between 25% and 50%. Please explain how Cascade's allocation factor was calculated for each subcategory of "Customer Services".
c. Please identify how frequently reviews and/or adjustments of the allocation factors are calculated for each subcategory of "Customer Services". Please provide any records of these reviews and records of any metrics used to calculate the allocation factors.
d. For "Credit Allocation", please provide records of time spent on each brand for those employees who are assigned to multiple brands.

**Response:**

a. If there is no rational basis to allocate a directors time then their time would be allocated evenly across all brands of the utility group. When a better rationale exists then that is used to determine the allocation percentages charged to each company. In 2017 there was only 1 position allocated equally to all brands of the utility group. For the allocation factors and working papers please see attached files:
AWEC-16 2018 SLD Extra Review MDU IT.xlsx

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

AWEC-16 Business Services Allocation Methodology 2015-2017.docx
AWEC-16 Business Services Allocation 6.9.16.xlsx
AWEC-16 MDU Gas supply Cost Allocation manual.docx
OPUC-287 Acctng & Finance Dep Allocations for 2017 and 2016.xlsx
Also see files in (b) for Customer Service allocations.

b. See attached files:
AWEC-16 CS Cost Allocation Manual 2017.docx
AWEC-16 CSC Cost Allocations Worksheet 2017.xlsx

c. The allocations for Customer Service are scheduled to be reviewed annually. Attached are the files showing the allocation factors for 2017 & 2018. OPUC-287 CS Cost Allocation Manual 2018.docx and OPUC-287 CS Cost Allocation Manual 2017.docx

d. The "Credit Allocation" is not based on employee time but on the employee activity. The allocation is based on three types of completed activities; accounts up for severance, closed accounts pending write-off, and broken payment plans. Following is the summary data used in calculating the allocations for 2017 and 2018.

12-2016 through 11-2017

Credit & Collections

| CIS_DIVISION | Severance | WRO | BPP | Total ToDo | % of Total | CNGC |
|---|---|---|---|---|---|---|
| CNGOR | 7625 | 2225 | 2177 | 12027 | 4.99% | 20.79% |
| CNGWA | 23,878 | 6,860 | 7,306 | 38,044 | 15.80% | GPNG |
| GPGMN | 5,019 | 753 | 862 | 6,634 | 2.75% | 2.92% |
| GPGND | 297 | 48 | 63 | 408 | 0.16% | IGC |
| IGCID | 56,500 | 10,511 | 22,413 | 19,998 | 36.13% | 36.31% |
| MDUMT | 18,121 | 3,284 | 4,960 | 26,365 | 10.95% | MDU |
| MDUND | 31,227 | 6,432 | 6,334 | 44,507 | 18.48% | 40.16% |
| MDUSD | 11,614 | 2,270 | 3,166 | 17,050 | 7.08% | |
| MDUWY | 6,551 | 872 | 1,379 | 8,802 | 3.65% | |
| | 160,812 | 33,713 | 46,310 | 240,835 | | |

11-2015 through 11-2016

Credit & Collections

| CIS_DIVISION | Severance | WRO | BPP | Total ToDo | % of Total | CNGC |
|---|---|---|---|---|---|---|
| CNGOR | 8,689 | 2,414 | 2,438 | 13,541 | 5.21% | 23.04% |
| CNGWA | 32,864 | 6,412 | 7,062 | 46,338 | 17.83% | GPNG |
| GPGMN | 6,037 | 874 | 854 | 7,765 | 2.99% | 3.15% |
| GPGND | 297 | 48 | 63 | 408 | 0.16% | IGC |
| IGCID | 44,562 | 12,820 | 22,413 | 79,795 | 30.71% | 30.71% |

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

| | | | | | | |
|---|---|---|---|---|---|---|
| MDUMT | 24,037 | 3,412 | 4,925 | 32,374 | 12.46% | MDU |
| MDUND | 34,334 | 6,432 | 7,199 | 47,965 | 18.46% | 43.10% |
| MDUSD | 13,144 | 2,350 | 3,636 | 19,130 | 7.36% | |
| MDUWY | 10,226 | 817 | 1,495 | 12,538 | 4.83% | |
| | 174,190 | 35,579 | 50,085 | 259,854 | | |

Utility Operations Support

Labor Distribution Allocation Methodology

**Administrative Services**

- Office Services
    - Responsibilities include: as requested by internal customers, which may include MDUR subsidiaries, coordination and printing of projects, purchase of office supplies and materials, bill inserting & mail, mail distribution and processing, records and information management, and coordination of remodel and rearrangement projects in the General Office and Annex.
    - Allocation Methodology: For all departments listed under Office Services the estimate of time is split first between the utility companies and MDU Resources, which includes all other subsidiaries. The portion of the utility time is split between MDU, CNGC, and IGC using several different methods listed below
        - Office Services Manager – Labor allocated to IGC and CNGC is based on meter counts and estimates for time required to manage responsibilities associated with integrated utility functions located in Boise.
        - Corporate Mailroom – The portion allocated to the other utilities is based on the number of mail pieces metered.
        - Print Shop – Allocations are split per the number of impressions.
        - Intranet & Graphic Project Coordinator – Currently labor allocated to IGC and CNGC is based on number of impressions, but as project requests for SharePoint increase, a new method for calculating may be needed.
        - Records Management – Labor allocated based on a combination of storage space and records requests, and estimates based on direct man-hours spent on specific RM projects that apply to all companies.
    - If the portion calculated for the other utilities is less than 5% all labor is allocated using the Montana-Dakota corporate factor.

- Buildings and Grounds
    - Responsible for building and equipment maintenance, security, contracted custodial services, and maintenance of the grounds and parking lots, for MDU General Office, Annex, and Mandan office buildings
    - Allocation Methodology:
        - The Montana-Dakota corporate factor is used to allocate Building and Grounds labor costs.

- Procurement
    - Responsible for procuring Gas, Electric, Power Production, and Service materials and Services for MDU and GPNG operations. Also works with MDU/GPNG inventories for the materials mentioned above.

- Allocation Methodology:
  - Primarily administrative (ES/GA) work, with Gas, Electric (Electric includes Power Production), split based on historic time studies and customer base.

- Transportation & Fleet
  - Responsible for planning, forecasting, budgeting, authorizing, scheduling, requisitioning, license & title management, fuel card administration, etc. of fleet requirements across the Utilities
  - Allocation Methodology:
    - Primary allocations split by E.S./G.A. as proportionate to job responsibilities and then based on gas/electric fleet unit counts at each business unit.
    - Fleet Maintenance Specialist position is based on current time being spent for each Utility. As this position's services have not yet fully integrated, it has been adjusted to reflect historic (2010) actual time being allocated to each utility.
    - Fleet Operations Specialist also provides support in Procurement Processes in the absence of Procurement personnel. Historic time approximations reflect the gas and electric allocation for this coverage. This will continue to be monitored and adjusted appropriately.

- Note: Exceptions may be made on an individual basis from these guidelines
  - Employees may be assigned special projects, and allocation methodology may be changed accordingly
  - Labor allocation may always be made on an actual time spent basis rather than these guidelines
  - Supervisors may alter these guidelines based on their individual scenario

# Customer Service Center

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.

## Payroll Costs

Customer Service payroll costs are allocated using five (5) different methodologies. Those allocation methodologies are:

- ***Customer Count (36 employees)***
  - 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:
    - Customer Service Director
    - Administrative Assistant
    - Manager, Customer Service
    - Supervisor, Customer Service
    - Customer Service Trainer
    - Customer Service Team Lead
    - Customer Project Analyst
    - Manager, Credit, Support, Program Development
    - Supervisor, Customer Support Service
    - Customer Service Team Lead (Support)
    - Customer Communications Coordinator
    - Customer Project Analyst I and II
    - Supervisor, Credit & Collections
    - Customer Service Team Lead (Credit)
    - Manager, Scheduling
    - Scheduling Analyst
    - Scheduling Lead

- ***Customer Call Time (116 employees)***
  - 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 (15 employees)***
  - Based on the number of 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 (20 employees)***
  - 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 (12 employees)***
  - 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

In addition to the allocation methodologies, there are three employees (Consumer Specialists) within the customer service area that are 100% charged to a single brand. This is based on them only having responsibility for the activity of that brand.

Each December, data for the five allocation methods listed above will be collected and used in determining new allocations for the following year.

For calendar year 2017, the following percentages will apply (based on data for the twelve month period of December 2015 to November 2016):

| Allocation Method | CNGC | IGC | MDU-GP Elec | MDU-GP Gas |
|---|---|---|---|---|
| Customer Count | 27.90% | 34.26% | 12.45% | 25.39% |
| Customer Call Time | 26.68% | 36.31% | 12.18% | 24.83% |
| Cleared Order Count | 29.04% | 29.63% | 14.15% | 27.18% |
| Credit To-Do's | 23.04% | 30.71% | 15.22% | 31.03% |
| E-mails | 29.14% | 40.66% | 9.94% | 20.26% |

**<u>Non-Payroll Costs</u>**

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.

CASE: UG 347
WITNESS: PAUL ROSSOW

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 800

# Opening Testimony

# September 27, 2018

**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/801.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony is to present Staff's proposed adjustment to certain Cascade Natural Gas Corporation's (CNGC or Company) administrative and general (A&G) expenses. The proposed adjustment I recommend is derived from review of multiple data requests, analysis of CNGC's 2017 Operation and Maintenance non-labor transactions, and Commission meals and entertainment policy.

**Q. Did you prepare an exhibit for this docket?**

A. No.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1. MISCELLANEOUS A&G

**Q. Please describe the miscellaneous A&G expenses at issue.**

A. The Federal Energy Regulatory Commission (FERC) has classified the FERC accounts shown in Table 1 below as A&G. Within these accounts are certain types of expenses like meals and entertainment, awards, gifts, and non-business travel that are considered miscellaneous A&G by Staff.

Table 1. Expenses within FERC Accounts.

| FERC No. | FERC Account | Expenses within FERC Accounts |
|---|---|---|
| 902 | Meter Reading | Meals, Food, Pizza Party, Ice Cream, Candy, and Cake |
| 903 | Customer Records and Collection | Gift Cards, Birthday Cards, Christmas Party, Coffee Mugs, Treats, Flowers, and Bowling |
| 908 | Customer Assistance | Baseball Tickets, and Meals |
| 921 | Office Supplies | Food, Meals, Party Supplies, and Employee Recognition |
| 926 | Employee Pensions and Benefits | Awards, Gift Cards, Party Gifts, and Entertainment |

**Q. Please provide a summary of the Company's filed proposal for administrative and general expenses.**

A. CNGC proposes including $6.2 million in the 2018 test year for total A&G expenses. CNGC obtained its test year estimate by escalating 2017 actual amounts by 1.7 percent after one adjustment. The one adjustment is the removal of $5,635[1] of miscellaneous A&G expenses Cascade concluded are not appropriate for recovery through customer rates. Cascade identified the expenses subsequently removed from the 2017 base year amount by

[1] CNGC/304, Peters/1.

performing a search for non-labor costs recorded in all FERC accounts for the 2017 base year reported in its response to Standard Data Request (SDR) No. 57.[2]

**Q. Please explain the Commission's historical treatment.**

A. Miscellaneous A&G expenses include awards, gift cards, food, meals, and entertainment. In Docket No. UE 197, the Commission adopted Staff's principle that costs for meals and entertainment, office refreshments and catering, gifts and awards are discretionary and should be shared equally by ratepayers and shareholders.[3] Accordingly, a 50 percent sharing of such expenses between customers and shareholders is routinely recommended by Staff. In addition, for any miscellaneous A&G expenses that are imprudent or excessive, Staff will recommend disallowance.

**Q. Please describe Staff's analysis of the Company's proposal for miscellaneous A&G expenses.**

A. To identify any miscellaneous A&G expenses that appear to be discretionary and not related to the provision of safe and reliable energy to customers, Staff reviewed the Company's 2017 A&G non-labor expenses provided in electronic spreadsheet format by CNGC in its revised response to SDR Nos. 57 and 58[4] and created tables to aid in Staff's analysis of miscellaneous A&G expenses.

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[2] CNGC/300, Peters/7 at 5-9. (SDR Nos. 57 and 58 require the utility to produce transaction summaries for all non-labor costs recorded in FERC Accounts during the base year.)

[3] See Order No. 09-020, pp. 20-21.

[4] SDR Nos. 57 and 58 require the Company to provide information for all non-labor costs recorded in all FERC accounts for the base year.

**Q. Does Staff propose an adjustment to the proposed 2018 test year expense?**

A. Yes. Table 1 summarizes the miscellaneous A&G adjusted expense amount identified by Staff that appear discretionary.

Table 1. Selected Miscellaneous Base Year Expenses

| | Staff Adjustment |
|---|---|
| Total discretionary Expenses | $79,019 |
| Less Company Adjustment | ($5,635) |
| | $73,384 |
| Disallowance | 50% |
| Expenses after Disallowance | $36,692 |
| Escalation Factor | 1.7% |
| Total Adjustment with Escalation | $37,316 |

**Q. What is Staff's recommendation regarding miscellaneous A&G expenses for the 2018 test year?**

A. Staff recommends decreasing the Company's miscellaneous A&G expenses in FERC accounts 902 through 930.2, resulting in a decrease to expense of ($37,316). Table 2 below indicates the proposed adjusted amount to be disallowed from each FERC Account.

Table 2. Disallowed Miscellaneous Expenses by FERC Account.

| FERC No. | FERC Account Description | Proposed Disallowance ($) |
|---|---|---|
| 902 | Meter Reading Expenses | $1,489 |
| 903 | Customer Records & Collect. Exp. | $56 |
| 908 | Customer Assistance Expenses | $378 |
| 921 | Office Supplies and Expenses | $11,755 |
| 926 | Employee Pensions and Benefits | $23,262 |
| 930.2 | Misc. General Expenses | $376 |
| Total | | $37,316 |

**Q. Is Staff recommending disallowances for costs incurred to read meters or for office supplies, etc.?**

A. No. The expenses that Staff proposes to disallow are for discretionary items such as office refreshments, catering, etc., that are recorded in the FERC Accounts listed above.

## ISSUE 2. CHARITABLE DONATIONS

**Q. Please summarize your adjustment**

A. I recommend the following escalated adjustment (Oregon-allocated):

| | |
|---|---|
| Charitable Donations | ($1,269) |

**Q. What expense does CNGC include in test year expense for charitable donations?**

A. CNGC's test year expense for cash contributions recorded to Charitable Donations is based on actual 2017 base year amounts escalated by 1.7 percent.[5]

**Q. Please explain the Commission's historical treatment.**

A. The Commission's historical treatment is to disallow recovery of the costs of utilities' charitable donations in rates charged for regulated services. These expenses are discretionary and are not required to provide safe and adequate service to customers. Further, Commission policy does not require customers to support causes in which they may not believe.[6]

**Q. Please describe Staff's analysis of the Company's proposal for Charitable Donations.**

A. To identify any charitable donation expenses that appear to not be related to the provision of safe and reliable energy to customers, Staff first created a pivot table of the Company's 2017 A&G non-labor expenses provided in electronic

[5] CNGC revised response to SDR No. 57.

[6] Order No. 09-020 at 21; OPUC Order No. 87-406 states at pp. 40-41, "Since community affairs expenditures are discretionary, the funds could be retained by the business's owners. Owners of unregulated businesses, rather than their customers, make community affairs contributions." Also see Order No. 91-186 at 16.

spreadsheet format by CNGC in its revised response to SDR No. 57. Staff identified one charitable donation transaction for the Association of Washington Business.

**Q. What is Staff's recommendation regarding charitable donations for the 2018 test year?**

A. Staff recommends removing costs of charitable donations from the test year expense. Staff proposes an adjustment based on Cascade's 2017 base year expense for charitable donations, $1,248, escalated by 1.7 percent to arrive at the amount Cascade included in its 2018 test year for charitable donations. This results in a decrease to expense (in FERC Account 921) of ($1,269).

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UG 347
WITNESS: PAUL ROSSOW

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 801

# Witness Qualifications Statement

# September 27, 2018

**WITNESS QUALIFICATION STATEMENT**

| | |
|---|---|
| NAME: | Paul Rossow |
| EMPLOYER: | Public Utility Commission of Oregon |
| TITLE: | Utility Analyst<br>Energy Resources & Planning Division |
| ADDRESS: | 201 High Street SE Suite 100<br>Salem OR 97301 |
| 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 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 355, UG 152, UG 153, UG 181, UG 186, UG 201, UG 221, UG 246, UG 284, and UG 344.<br><br>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. |

CASE: UG 347
WITNESS: JEFFREY WATSON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 900

# Opening Testimony

# September 27, 2018

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

A. My name is Jeffrey Watson. I am a Consumer Services 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/903.

**Q. What is the purpose of your testimony?**

A. My testimony will discuss my analysis of the company's implementation of Accounting Standards Update (ASU) 2017-07 and pension expense and the Company's medical benefit expense.

**Q. Did you prepare an exhibit for this docket?**

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

- Exhibit Staff/902, which is my workpaper and analysis of pension expenses.
- Exhibit Staff/903, which is my workpaper and analysis of medical benefit expenses.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1. IMPLEMENTATION OF ASU 2017-07

**Q. What is ASU 2017-07?**

**A.** ASU 2017-07 is an accounting standard issued by the Financial Accounting Standards Board (FASB) intended to improve presentation of net benefit costs in financial reports for both public and private companies. Previously, a lack of formal guidance on the topic led to a variety of methods in disclosing these costs. The guidance states that companies must report pension expenses listed on their financial statements under the same line as other compensation costs. Additionally, while Net Periodic Benefit Cost (NPBC) is an aggregation of several cost components (such as interest cost, actual return on assets, etc.), ASU 2017-07 states that only the service cost component[1] of NPBC is eligible for capitalization.

**Q. Has there been any further guidance specific to the energy industry regarding implementation of the accounting standard?**

**A.** Yes, the Federal Energy Regulatory Commission (FERC) has provided its own guidance to regulated companies seeking help understanding whether and how to implement the new standard. FERC recognized that its position has been to recognize pension and post-retirement benefits other than pension (PBOP) costs as single line items, and that those costs are attributable to the calculation of Net Utility Operating Income in their entirety. The FERC accounting guidance directs that utilities under FERC

[1] The service cost is the actuarial present value of benefits related to services rendered during the current reporting period.

jurisdiction should continue to record pension and PBOP costs in their entirety to the FERC accounts that they have already been using - Account 926 for jurisdictional public utilities and licensees, natural gas companies, and centralized service companies. However, FERC stated that it is appropriate if a company chooses to continue to capitalize both the service cost component and non-service cost components of pension and PBOP expenses, provided the pension and PBOP costs are based on appropriate labor costs and have a definite relation to construction:

> Because there is no definitive requirement under the Uniform Systems of Accounts requiring specific identification of pension and PBOP cost components to be capitalized, outside of the requirement for the capitalization to be based on appropriate labor costs and to have a definite relation to construction, jurisdictional entities may elect to follow the capitalization required under ASU No. 2017-07. It is also acceptable to continue capitalizing all of the pension and PBOP costs, as companies have done so prior to the issuance of the ASU.[2]

**Q. Did the Company elect to apply the new accounting standard?**

A. Yes. The Company's 2017 financial statements include the following statement:

> The Company will reclassify all components of net periodic benefit costs, except for the service cost component, from operating expenses to other income (expense) on the Consolidated Statements of Income for all years presented prior to January 1, 2018, beginning in the first quarter of 2018, with no impact to earnings. The guidance will not have a material impact on the Company's disclosures or cash flows.[3]

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[2] *https://www.ferc.gov/enforcement/acct-matts/docs/AI18-1-000.pdf*

[3] *See In the Matter of CASCADE NATURAL GAS CORPORATION Annual Report (FERC Form No. 2), Oregon Supplement*, Docket No. RG 33, Supplemental Application (April 24, 2018).

**Q. Briefly, what is the impact of the new accounting standard on costs in this rate case?**

**A.** The new accounting standard does not change how overall pension and postretirement benefit FAS 87 expense is determined. The standard requires a smaller proportion of the overall pension and postretirement benefit to be included in the cost of capital assets and a correspondingly larger portion to be included in periodic operating costs. The standard also changes how overall pension and postretirement benefit are presented in financial statements.

**ISSUE 2. PENSION AND POST-RETIREMENT BENEFIT EXPENSE**

**Q. Please provide a summary of the Company's filed proposal for pensions.**

A. The Company projects a 2018 test year pension expense of $276,000 on a total company basis.

**Q. Please explain the Commission's historical treatment of pension expenses.**

A. The Commission policy is to include only the actuarially determined FAS 87 expense in rates rather than cash contributions to the plan.[4] Though most expenses approved for inclusion in rates are based on cash costs, cash payments from a company to its pension fund can be volatile from year to year, depending on market and interest rates, as well as changing pension regulations. Because of the volatility of these cash payments, the Commission currently uses accrual pension costs as a proxy for cash payments. These accrual pension costs are calculated in accordance with applicable standardized accounting guidance and known as Financial Accounting Standard (FAS) 87 expense.

**Q. Please describe Staff's analysis of the Company's proposal for pension expense.**

A. Staff reviewed the Company's responses to nine Staff data requests related to pension costs as well as responses to standard data requests regarding

[4] *See In the Matter of PUBLIC UTILITY COMMISSION OF OREGON, Investigation into Treatment of Pension Costs in Utility Rates,* Docket No. UM 1633, Order No. 15-226 (Aug 03, 2015).

pensions and post-retirement medical expenses. The Company's responses provided details regarding the Company's investment strategy, actuarial recommendations, and the overall health of the pension plan.

As described above, the Commission has historically relied on FAS 87 expense as a reasonable representation of cash costs in any given year. The FAS 87 expense amount is calculated and determined by third-party actuaries. Though most of the calculation's inputs are based on actual costs and amounts, two of the inputs require a degree of subjective judgment; these are the expected long-term market rate of return on pension assets (EROA) and the expected discount rate. Typically in reviewing pension costs as part of a general rate case, Staff analyzes these two inputs, reviews them for reasonableness, verifies the calculation, and potentially recommends an adjustment to the proposed cost based on recommended changes to the EROA or discount rate.

To compare the Company's EROA and discount rate used in the FAS 87 expense calculation to those of other utility companies regulated in Oregon, Staff constructed the following table using those utilities' SEC 10k filings. As seen in the below table, the Company's EROA is below the average of the companies shown, while showing little movement year over year. The discount rate for benefit obligation is also generally below the average.

| Expected Rate of Return on Assets used in Pension | | | | | | |
|---|---|---|---|---|---|---|
| **Company** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Cascade | 7.00% | 7.00% | 7.00% | 6.75% | 6.75% | 6.75% |
| Avista | 6.60% | 6.60% | 5.30% | 5.40% | 5.87% | NA |
| Idaho Power | 7.75% | 7.75% | 7.50% | 7.50% | 7.50% | NA |
| NW Natural | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | NA |
| PacifiCorp | 7.50% | 7.50% | 7.25% | 7.00% | 6.75% | NA |
| PGE | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | NA |
| **Average** | 7.37% | 7.37% | 7.01% | 6.98% | 7.02% | 6.75% |

| Discount Rate for benefit obligation | | | | | | |
|---|---|---|---|---|---|---|
| **Company** | **2013** | **2014** | **2015** | **2016** | **2017** | **2018** |
| Cascade | 3.68% | 4.56% | 3.72% | 4.03% | 3.86% | 3.40% |
| Avista | 5.10% | 4.21% | 4.57% | 4.26% | 3.71% | NA |
| Idaho Power | 4.20% | 4.25% | 4.25% | 4.60% | 4.45% | NA |
| NW Natural | 4.73% | 3.85% | 4.21% | 4.00% | 3.52% | NA |
| PacifiCorp | 4.05% | 4.80% | 4.00% | 4.50% | 4.10% | NA |
| PGE | 4.84% | 4.02% | 4.36% | 4.17% | 3.65% | NA |
| **Average** | 4.58% | 4.23% | 4.28% | 4.31% | 3.89% | 3.40% |

Finally, Staff reviewed the funded status of the Company's pension and found its unfunded obligation decreasing year over year since 2014.

**Q. Does Staff find the total company proposed 2018 test year pension expense reasonable?**

A. Yes. The Company's responses to Staff data requests shows the Company is relying on the advice of a third-party actuary for the overall investment strategy and to determine discount rates. Further, the continued improvement of the funded status allays any concerns that the Company is making irresponsible or unreasonable elections. Staff's analysis shows that the Company has selected strategies and rates that are within a reasonable range, as measured against

other Oregon regulated utilities and does not suggest an adjustment to the Company's FAS 87 expenses.

**Q. Does Staff have an adjustment to the Oregon-allocated test year pension?**

A. Not at this time. Staff has sent additional data requests to the Company regarding the allocation of pension expense and the responses are pending.

## ISSUE 3. MEDICAL BENEFIT EXPENSE

**Q. Please provide a summary of the Company's filed proposal for medical benefit expense.**

A. The company made no reference to expenses or expectations regarding medical benefits in its opening testimony. Per its response to Standard Data Request (SDR) No. 63, the Company has budgeted for medical, dental, and life insurance costs to decrease in 2018 to $904,873 from a 2017 amount of $955,570.28 (Oregon allocated), a decrease of 5.3%.

**Q. Please explain the Commission's historical treatment of this issue.**

A. The Commission will consider the reasonableness of a compensation package. Staff's approach to medical benefits is to examine benefit spending, as well as changes in policies and benefit levels, and compare those to the company's own trends as well as national trends and averages such as those provided by the annual Kaiser Family Foundation (KFF) Health Benefits Survey.

**Q. Please describe Staff's analysis of the Company's proposal for medical benefits.**

A. Staff began by reviewing the Company's responses to SDR Nos. 63-67, and issued additional data requests to supplement the information provided. The Company provided data on premiums shared between employees and the Company from 2015 through the test year. Staff has analyzed the data to observe cost escalation trends, as well as to match against averages from the Kaiser Family Foundation (KFF) Employer Healthcare Survey (contains data through 2016).

Staff's analysis finds the Company's premiums are weighted slightly in favor of employees, with the company bearing a slightly higher share of premiums for all types of coverage than the Oregon average (per KFF). The Company states they currently limit the employee portion of premiums to no more than 20 percent.

Premiums increased by approximately five percent in 2015 and 2016, which is in line with national trends, but grew by 15 percent in 2017. Despite the overall reduction in spending, the Company projects a 12 percent increase in premiums for the traditional medical plan for both employees and the Company. The Company states the increase in premiums is due to increased utilization and medical costs.[5]

Overall participation rates in the benefit programs offered by the Company have remained steady from 2014 through the base year, averaging 93.7 percent. Participation at the plan level shows a steep drop in the percentage of employees enrolled in the Company's Traditional Medical Plan from 2016 to 2017 as those employees migrated to the newly available Health Savings Account (HSA)/High-Deductible plan. For 2016, the Company shows 73 percent of its employees enrolled in the Traditional Medical Plan and 27 percent of its employees in the HSA plan. In 2017, participation in the Traditional Medical Plan dropped to 33 percent, with the remaining 67 percent of employees split between two HSA plans. This is an inversion of the average national distribution of health plan enrollment for covered workers per the KFF

[5] Company Response to Staff DR No. 189.

study. The study shows that (for firms with 200 or more workers) 48 percent of workers nationally are covered by traditional medical plans, such as Preferred Provider Organization plans and 30 percent of workers are covered by HSA plans.

The Company states the change in enrollment preference was due to plan design changes for the Traditional Medical Plan as well as enhanced communication regarding high deductible plans and the advantages of health savings accounts. The Company's decision to offer a HSA plan as an alternative to its employees matches national trends.

Staff has also reviewed details of the policies and finds they provide reasonable coverage compared to the national average, again per the KFF study. Additionally, Staff reviewed the spending records for the base year given in SDR No.57 and found no unusual or misallocated spending in the Company's records.

**Q. Has the Company consistently forecast its medical benefit expenses accurately?**

A. No. In Cascade's general rate case filed in 2015 (Docket No. UG 287), Staff determined the Company displayed a pattern of over-budgeting for medical expenses. Although the trend toward over-budgeting was in decline at that time of that rate case, the Company had budgeted as much as 35 percent over actual costs in 2012 and 29 percent in 2013. For this reason, Staff determined that an examination of the Company's projected and actual medical spending was warranted. Staff has sent data requests in this docket to gain data for

analysis of the Company's projections for medical expenses. However, the responses have not been sufficient for Staff to analyze the Company's trend for estimating expenses in this category. Staff will continue to analyze this issue.

**Q. Please summarize your analysis on the topic of medical benefit spending.**

A. The Company is providing health benefits that are similar in cost and coverage to those offered by other companies of its size in the country. Where the Company differs, in its percentage of employees enrolled in HAS plans versus traditional health plans, the Company's explanation for the difference is sufficient to allay Staff's concerns. In short, nothing about the Company's premium sharing or overall premium costs stands out as being unreasonable.

**Q. Does Staff propose an adjustment to the proposed 2018 test year?**

A. No. The Company's health plans and benefit offerings are reasonable compared to national averages. However, Staff intends to continue analyzing the Company's trend in projecting its medical expenses and may propose an adjustment if it is determined that the Company's trend of over-budgeting for medical expenses has not changed.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UG 347
WITNESS: JEFFREY WATSON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 901

# Witness Qualifications Statement

# September 27, 2018

# WITNESS QUALIFICATION STATEMENT

NAME: Jeffrey Watson

EMPLOYER: Public Utility Commission of Oregon (Commission)

TITLE: Consumer Specialist, Consumer Services;
Analyst, E-RFA

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

EDUCATION: Bachelor of Science, Economics
Oregon State University, Corvallis, OR
Associate of Arts
Chemeketa Community College, Salem, OR

EXPERIENCE: I have been employed by the Commission since January of 2016 as a Consumer Specialist in the Consumer Services Division (Consumer Services), and as an analyst in the Energy Rates, Finance and Audit (E-RFA) Division. For Consumer Services, I investigate and resolve customer claims of inappropriate action by regulated utilities and other service providers. For E-RFA, I support audits and Cost of Capital modeling. My analysis also covers a variety of other financial and general rate case topics as reflected in the current general rate cases of Northwest Natural Gas Corporation (NWN UG 344) and Portland General Electric Company (PGE UE 335).

Prior to my work at the Commission, I was employed by T-Mobile for six years. First I developed and led continuing education courses, both as a trainer and subject matter expert for 600+ representatives and leaders on customer service and sales operations topics.

Next at T-Mobile, I managed a specialized team of customer service representatives to resolve escalated, executive level, and outside-of-policy customer issues. I reviewed call center operations and developed policies based on my analysis of the issues tracked by my team. I presented and defended my analysis and recommendations to site and regional leadership. My recommendations set performance goals to confirm successful resolution of issues and ensured ongoing service quality.

CASE: UG 347
WITNESS: JEFFREY WATSON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 902

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

**STAFF EXHIBIT 902**

**PROVIDED IN ELECTRONIC FORMAT ONLY**

CASE: UG 347
WITNESS: JEFFREY WATSON

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 903

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

**STAFF EXHIBIT 903**

**PROVIDED IN ELECTRONIC FORMAT ONLY**

## Expected Rate of Return on Assets used in Pension Calculations

| Company | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| Cascade | 7.00% | 7.00% | 7.00% | 6.75% | 6.75% | 6.75% |
| Avista | 6.60% | 6.60% | 5.30% | 5.40% | 5.87% | NA |
| Idaho Power | 7.75% | 7.75% | 7.50% | 7.50% | 7.50% | NA |
| NW Natural | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | NA |
| PacifiCorp | 7.50% | 7.50% | 7.25% | 7.00% | 6.75% | NA |
| PGE | 7.50% | 7.50% | 7.50% | 7.50% | 7.50% | NA |
| **Average** | 7.37% | 7.37% | 7.01% | 6.98% | 7.02% | 6.75% |

## Discount Rate for benefit obligation

| Company | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|---|
| Cascade | 3.68% | 4.56% | 3.72% | 4.03% | 3.86% | 3.40% |
| Avista | 5.10% | 4.21% | 4.57% | 4.26% | 3.71% | NA |
| Idaho Power | 4.20% | 4.25% | 4.25% | 4.60% | 4.45% | NA |
| NW Natural | 4.73% | 3.85% | 4.21% | 4.00% | 3.52% | NA |
| PacifiCorp | 4.05% | 4.80% | 4.00% | 4.50% | 4.10% | NA |
| PGE | 4.84% | 4.02% | 4.36% | 4.17% | 3.65% | NA |
| **Average** | 4.58% | 4.23% | 4.28% | 4.31% | 3.89% | 3.40% |

Note: Data for Cascade taken from responses to SDR 59 provided in UG 347 and UG 287. All other data taken from annual Form 10K filings via SEC

| | UG 347 SDR 59 Response (2018) | | | | | UG 305 SDR 59 Response (2016) | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | 2017 | 2016 | 2015 | 2014 | | 2015 | 2014 | 2013 | 2012 |
| | Test Year | Base Year | Base Year – 1 | Base Year– 2 | Base Year– 3 | Test Year | Base Year | Base Year – 1 | Base Year – 2 | Base Year – 3 |
| Obligation at 12/31/2018 | | | $90,736,482 | $91,579,830 | $97,334,576 | | | $97,334,576 | $81,736,849 | $91,932,961 |
| Fair Value of Plan | | $80,266,754 | $81,827,263 | $72,376,574 | $67,194,603 | | $72,376,574 | $67,194,603 | $63,514,799 | $61,515,517 |
| Actual Return on Assets | | | | | | | | | | |
| Benefits Paid | | | | | | | | | | |
| Funded Status | | | | | | | | | | |
| Accumulated Benefit Obligation | | | | | | | | | | |
| Funded Ratio | | 80% | 80% | 80% | 80% | | 80% | 80% | 84.17% | 80% |
| | | | | | | | | | | |
| Service Cost | | $0 | $0 | $0 | $0 | | $0 | $0 | $1,252,349 | $1,075,305 |
| | | | | | | | | | | |
| Interest Cost | | $3,405,696 | $3,591,523 | $3,540,170 | $3,619,743 | | $3,540,170 | $3,619,743 | $3,296,525 | $3,506,605 |
| Expected Return on Assets | | $4,977,995 | $5,038,118 | $4,462,752 | $4,292,182 | | $4,462,752 | $4,292,182 | $4,071,689 | $4,527,611 |
| Amortization of Transition Asset | | | | | | | | | | |
| Amortization of Prior Service Cost | | $0 | $0 | $0 | $0 | | $0 | $0 | $0 | ($155,991) |
| Recognized (Gain) Loss | | $1,372,966 | $1,269,966 | $1,375,422 | $1,031,162 | | $1,375,422 | $1,031,162 | $1,403,946 | $3,410,842 |
| Net Periodic Pension Cost (Income) | | $199,333 | $176,629 | $452,840 | $358,723 | | $452,840 | $358,723 | $628,782 | $3,486,194 |
| | | | | | | | | | | |
| Company's Contribution to Plan | | $0 | $0 | $2,471,701 | $2,475,877 | | $2,471,701 | $2,475,877 | $2,185,778 | $1,803,754 |
| Discount Rate for Benefit Obligation | | 3.86% | 4.03% | 3.72% | 4.56% | | 3.72% | 4.56% | 3.68% | 4.15% |
| Discount Rate for Annual Expense | | | | | | | | | | |
| | | | | | | | | | | |
| Long-term Rate of Return on Assets | | 6.75% | 6.75% | 7.00% | 7.00% | | 7.00% | 7.00% | 7.00% | 7.75% |
| Actual Rate of Return on Assets | | | | | | | | | | |

**Note: CNG's original response to SDR 59 for UG 347 showed the below results for rows 3 and 4. Staff believes this was a clerical error and assumes the corrected values shown above.**

| | Test Year | Base Year | Base Year – 1 | Base Year– 2 | Base Year– 3 |
|---|---|---|---|---|---|
| Obligation at 12/31/2018 | | | | | |
| Fair Value of Plan | | | $90,736,482 | $91,579,830 | $97,334,576 |
| Actual Return on Assets | | $80,266,754 | $81,827,263 | $72,376,574 | $67,194,603 |

| | 2014 | 2015 | 2016 | 2017 | 2018 |
|---|---|---|---|---|---|
| **Expected Rate of Return (EROA)** | 7.00% | 7.00% | 6.75% | 6.75% | 6.75% |
| **EROA Discount Rate** | 4.56% | 3.73% | 4.03% | 3.86% | 3.40% |
| **Actual Rate of Return (AROA)** | 7.78% | -3.00% | 9.04% | 14.92% | |
| **AROA Discount Rate** | 6.46% | 6.25% | 6.05% | 5.85% | |
| **Funded Status** | ($24,815,817) | ($14,111,497) | ($12,186,713) | ($8,438,377) | |

| Traditional Medical Plan (2018) | Employee Premium | Employee Share | Employee % Change | Company Premium | Company Share | Company % Change | Total Premium | Total % Change |
|---|---|---|---|---|---|---|---|---|
| Employee | $120 | 20% | 12% | $479 | 80% | 12% | $599 | 12% |
| Employee + Child | $204 | 20% | 12% | $813 | 80% | 12% | $1,017 | 12% |
| Employee + Spouse | $276 | 20% | 12% | $1,100 | 80% | 12% | $1,376 | 12% |
| Employee + Children | $251 | 20% | 12% | $1,006 | 80% | 12% | $1,257 | 12% |
| Family | $376 | 20% | 12% | $1,506 | 80% | 12% | $1,882 | 12% |

| Traditional Medical Plan (2017) | Employee Premium | Employee Share | Employee % Change | Company Premium | Company Share | Company % Change | Total Premium | Total % Change |
|---|---|---|---|---|---|---|---|---|
| Employee | $107 | 20% | 29% | $428 | 80% | 12% | $535 | 15% |
| Employee + Child | $182 | 20% | 27% | $726 | 80% | 12% | $908 | 15% |
| Employee + Spouse | $246 | 20% | 15% | $983 | 80% | 15% | $1,229 | 15% |
| Employee + Children | $224 | 20% | 26% | $898 | 80% | 13% | $1,122 | 15% |
| Family | $336 | 20% | 15% | $1,344 | 80% | 15% | $1,680 | 15% |

| Traditional Medical Plan (2016) | Employee Premium | Employee Share | Employee % Change | Company Premium | Company Share | Company % Change | Total Premium | Total % Change |
|---|---|---|---|---|---|---|---|---|
| Employee | $83 | 18% | 5% | $382 | 82% | 5% | $465 | 5% |
| Employee + Child | $143 | 18% | 4% | $647 | 82% | 5% | $790 | 5% |
| Employee + Spouse | $213 | 20% | 4% | $856 | 80% | 5% | $1,069 | 5% |
| Employee + Children | $178 | 18% | 5% | $798 | 82% | 5% | $976 | 5% |
| Family | $292 | 20% | 5% | $1,169 | 80% | 5% | $1,461 | 5% |

| Traditional Medical Plan (2015) | Employee Premium | Employee Share | Employee % Change | Company Premium | Company Share | Company % Change | Total Premium | Total % Change |
|---|---|---|---|---|---|---|---|---|
| Employee | $79 | 18% | 4% | $364 | 82% | 5% | $443 | 5% |
| Employee + Child | $137 | 18% | 0% | $617 | 82% | -1% | $754 | -1% |
| Employee + Spouse | $204 | 20% | 7% | $816 | 80% | 6% | $1,020 | 6% |
| Employee + Children | $170 | 18% | 5% | $761 | 82% | 5% | $931 | 5% |
| Family | $278 | 20% | 5% | $1,116 | 80% | 5% | $1,394 | 5% |

| Traditional Medical Plan (2014) From UG 305 SDR 64 | Employee Premium | Employee Share | | Company Premium | Company Share | | Total Premium |
|---|---|---|---|---|---|---|---|
| Employee | $76 | 18% | | $346 | 82% | | $422 |
| Employee + Child | $137 | 18% | | $622 | 82% | | $759 |
| Employee + Spouse | $191 | 20% | | $770 | 80% | | $961 |
| Employee + Children | $162 | 18% | | $724 | 82% | | $886 |
| Family | $264 | 20% | | $1,060 | 80% | | $1,324 |

Data taken from Company responses to SDRs 63 and 65 and Kaiser Family Foundation 2017 Employer Health Benefits Survey; amounts are monthly.

| Traditional Medical Plan (2016) | KFF OR Avg Employee | KFF OR Avg Compa | KFF OR Avg Total | KFF OR Avg Employ | KFF OR Avg Compa | KFF OR Avg Total |
|---|---|---|---|---|---|---|
| Employee | $ 86 | $ 412 | $ 498 | 14% | 0% | 3% |
| Employee + Child | $ 258 | $ 768 | $ 1,027 | 6% | 9% | 8% |
| Employee + Spouse | | | | | | |
| Employee + Children | | | | | | |
| Family | $ 350 | $ 1,077 | $ 1,427 | -11% | 4% | 0% |

| Traditional Medical Plan (2015) | KFF OR Avg Employee | KFF OR Avg Compa | KFF OR Avg Total | KFF OR Avg Employ | KFF OR Avg Compa | KFF OR Avg Total |
|---|---|---|---|---|---|---|
| Employee | $ 75 | $ 410 | $ 485 | -2% | 3% | 2% |
| Employee + Child | $ 245 | $ 703 | $ 948 | 0% | 9% | 7% |
| Employee + Spouse | | | | | | |
| Employee + Children | | | | | | |
| Family | $ 394 | $ 1,034 | $ 1,428 | 4% | 5% | 5% |

| Traditional Medical Plan (2014) From UG 305 SDR 64 | KFF OR Avg Employee | KFF OR Avg Compa | KFF OR Avg Total | KFF OR Avg Employ | KFF OR Avg Compa | KFF OR Avg Total |
|---|---|---|---|---|---|---|
| Employee | $ 76 | $ 399 | $ 476 | 14% | 3% | 5% |
| Employee + Child | $ 244 | $ 644 | $ 888 | -4% | -2% | -3% |
| Employee + Spouse | | | | | | |
| Employee + Children | | | | | | |
| Family | $ 380 | $ 981 | $ 1,361 | 14% | 3% | 5% |

CNG OPUC DR 63

| | | TOTAL COMPANY | | | | |
|---|---|---|---|---|---|---|
| | | 2018 | 2017 | 2016 | 2015 | 2014 |
| 5192 | Other Benefits | 74,015.23 | 71,098.79 | 58,786.29 | 81,548.60 | 187,158.19 |
| 5194 | Medical/Dental & Life Insurance | 3,497,401.95 | 3,533,398.57 | 3,102,827.96 | 3,017,395.29 | 2,808,428.22 |
| 5195 | Pension | 236,259.00 | (110,892.53) | (71,162.68) | (106,803.73) | 287,890.21 |
| 5196 | Post Retirement | 274,923.00 | 149,434.26 | 275,553.22 | 232,241.86 | 91,575.46 |
| 5197 | 401-K Plan | 2,468,873.23 | 2,645,472.03 | 2,431,912.68 | 2,284,787.22 | 2,254,741.48 |
| 5199 | Workers Compensation | 170,754.46 | 292,566.84 | 144,366.73 | 236,735.98 | 228,012.89 |
| 5921 | Supplemental Defined Plan & Contribution | 686,887.00 | (291,752.32) | 169,401.44 | 672,603.62 | 444,772.38 |
| | | **$ 7,409,113.87** | **$ 6,289,325.64** | **$ 6,111,685.64** | **$ 6,418,508.84** | **$ 6,302,578.83** |

| | | OREGON TOTAL | | | | |
|---|---|---|---|---|---|---|
| | | 2018 | 2017 | 2016 | 2015 | 2014 |
| 5192 | Other Benefits | 18,884.00 | 17,813.42 | 15,697.16 | 20,592.86 | 45,381.08 |
| 5194 | Medical/Dental & Life Insurance | 904,873.00 | 955,570.28 | 802,762.47 | 784,319.21 | 717,623.89 |
| 5195 | Pension | 63,406.00 | (26,719.00) | (18,092.51) | (28,263.38) | 70,660.61 |
| 5196 | Post Retirement | 31,437.00 | 30,814.50 | 63,534.14 | 52,522.98 | 19,385.19 |
| 5197 | 401-K Plan | 637,497.00 | 687,291.26 | 617,363.31 | 577,536.20 | 562,942.96 |
| 5199 | Workers Compensation | 45,249.00 | 139,983.97 | 77,499.70 | 91,541.07 | 69,227.76 |
| 5921 | Supplemental Defined Plan & Contribution | - | (72,821.36) | 41,892.97 | 163,240.94 | 108,079.70 |
| | | **$ 1,701,346.00** | **$ 1,731,933.07** | **$ 1,600,657.24** | **$ 1,661,489.88** | **$ 1,593,301.19** |

**Explanations**

1.) Amounts reflected are after employer/employee sharing.

2.) Assumptions for Base Year are Budgeted O&M Amounts except 5921 SERP. Test year allocation for SERP for Oregon was calculated based on actuals of 2017.

Kaiser Family Foundation 2016 Health Survey Annual Trends - Oregon

**Premiums**

| Individual Employee | | | |
|---|---|---|---|
| | Employee Share | Company Share | Total Premium |
| 2013 | 804 | 4645 | 5449 |
| 2014 | 914 | 4793 | 5707 |
| 2015 | 898 | 4924 | 5822 |
| 2016 | 1028 | 4946 | 5974 |

| Employee + 1 | | | |
|---|---|---|---|
| | Employee Share | Company Share | Total Premium |
| 2013 | 3028 | 7914 | 10942 |
| 2014 | 2922 | 7733 | 10655 |
| 2015 | 2935 | 8437 | 11372 |
| 2016 | 3100 | 9221 | 12321 |

| Whole Family | | | |
|---|---|---|---|
| | Employee Share | Company Share | Total Premium |
| 2013 | 4327 | 11529 | 15856 |
| 2014 | 4555 | 11775 | 16330 |
| 2015 | 4729 | 12412 | 17141 |
| 2016 | 4200 | 12927 | 17127 |

**Year Over Year Change**

| Individual Employee | | | |
|---|---|---|---|
| | Employee Share | Company Share | Total Premium |
| 2014 | 13.7% | 3.2% | 4.7% |
| 2015 | -1.8% | 2.7% | 2.0% |
| 2016 | 14.5% | 0.4% | 2.6% |

| Employee + 1 | | | |
|---|---|---|---|
| | Employee Share | Company Share | Total Premium |
| 2014 | -3.5% | -2.3% | -2.6% |
| 2015 | 0.4% | 9.1% | 6.7% |
| 2016 | 5.6% | 9.3% | 8.3% |

| Whole Family | | | |
|---|---|---|---|
| | Employee Share | Company Share | Total Premium |
| 2014 | 5.3% | 2.1% | 3.0% |
| 2015 | 3.8% | 5.4% | 5.0% |
| 2016 | -11.2% | 4.1% | -0.1% |

Notes

- All amounts are for annual expense
- The Medical Expenditure Panel Survey (MEPS) Insurance Component is an annual survey of establishments that collects information about employer-sponsored health insurance offerings in the United States.
- Figures may not sum to totals due to rounding.
- Sources Agency for Healthcare Research and Quality, Center for Financing, Access and Cost Trends. Medical Expenditure Panel Survey (MEPS)- Insurance Component, 2013-2016; Tables II.C.1, II.C.2, II.C.3 available at: [Medical Expenditure Panel Survey (MEPS)](https://meps.ahrq.gov/mepsweb/data_stats/quick_tables_results.jsp?component=2&subcomponent=2&year=2016&tableSeries=-1&tableSubSeries=CDE&searchText=&searchMethod=1&Action=Search).
- Definitions and descriptions of the methods used for this survey can be found in the [Technical Appendix](http://meps.ahrq.gov/mepsweb/survey_comp/ic_technical_notes.shtml).

CASE: UG 347
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION

# STAFF EXHIBIT 1000

## Opening Testimony

## September 27, 2018

**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/1001.

**Q. What is the purpose of your testimony?**

A. The purpose of my testimony to provide Staff's review of Cascade Natural Gas Corporation's (Cascade or Company) expense for low-income programs and materials and supplies 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 1001—Witness Qualifications Statement
Exhibit 1002—Company responses to Staff Data Request Nos. 200, 201, and 202 regarding low-income programs.

**Q. How is your testimony organized?**

A. My testimony is organized as follows:

## ISSUE 1. LOW INCOME PROGRAMS

**Q. Can you describe Cascade's low-income programs?**

A. Yes. Cascade provides a number of programs to assist customers in meeting their energy bill obligations as well as conservation programs. Cascade has its Low-income Rate Assistance Program (LIRAP) and its Winter Help Program to provide bill-pay assistance to low-income customers. Cascade also provides conservation programs through the Energy Trust of Oregon and through community action agencies specifically serving low-income customers. In ADV 157, Cascade filed for and received approval of its request to make its Conservation Achievement Tariff (CAT) pilot program a permanent program.[1] The CAT supplements the long-standing low-income conservation program by providing full funding of conservation measures thus allowing substantially more low-income homes to be weatherized. In fact, this program has been so successful the Company has, working in conjunction with Commission Staff, had to apply upper bounds on the program to keep costs more in line with mandated spending limits on low-income weatherization for electric utilities.[2]

Finally, the Company continues to offer a Budget Payment Plan, which provides an option to customers to make flat payments for a period of time. 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

[1] CNGC/100, Kivisto/7.
[2] CNGC/100, Kivisto/6-7.

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.

**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. What is the Commission's historical treatment of this issue?**

A. Cascade obtains funding from customers to pay for the programs through a public purpose charge 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). Staff reviewed the Company filing and reviewed the Company's response to Data Request No. 201 to ensure there is not double recovery; that is, recovering costs both in separate tariff riders and in base rates.

**Q. What is your analysis of the Company's proposal for low-income program 2018 test-year expense?**

A. The Company's 2018 test-year estimate for low-income program expense is based on the associated 2016 unadjusted expenditures. Staff reviewed Cascade's 2016 low-income program expenses incurred to ensure that they were correctly recorded and prudent. Staff found no errors in recording and did not identify any expenses that were imprudent. Staff reviewed the Company's response to Staff Data Request No. 201 and created a spending summary for

each expense, including account number and object description, to aid in Staff's analysis.

**Q. Did you make any adjustments to Cascade's low-income program 2018 test-year expenditures?**

A. No.

**Q. What is Staff's recommendation regarding low-income programs for the future?**

A. Staff's recommendation is to continue accounting for low-income programs separate from other Company activities and separate from rate cases. This includes administrative costs that could have the potential for double recovery. Cascade has noted that none of low-income program related costs, including administrative costs, should be recoverable in the rate case.

## ISSUE 2. MATERIALS AND SUPPLIES

**Q. Please describe materials and supplies costs.**

A. Materials and supplies are used by the Company in the course of providing of utility service.

**Q. Please describe the Commission's ratemaking treatment of materials and supplies costs.**

A. For OPUC regulated natural gas companies, costs of materials and supplies can be recovered through rates in three ways. Material and supplies costs can be expensed in cost of service. For example, material and supplies such as office supplies and safety supplies may be purchased and expensed in the process of providing services. Material and supplies are also purchased and capitalized in capital projects. Lastly, material and supplies are purchased and inventoried for later use.

**Q. Will all three types of material and supplies costs be addressed in this testimony?**

A. No. I will address material and supplies expense in cost of service and material and supplies inventory in rate base. Staff Witness John Fox is reviewing capitalized plant and his review will consider material and supplies capitalized in projects.

**Q. Please describe what you found for materials and supplies expense in cost of service.**

A. I reviewed 2017 transactional data provided by the Company in its response to DR No. 57. I filtered this transactional data by the object code fields that describes the type of expense. I selected Object codes 5300, 5853 and 5630.

**Q. Do you have an adjustment based on your analysis?**

A. No.

**Q. Please explain your analysis of materials and supplies in rate base.**

A. Cascade includes approximately $2.437 million in the test year rate base. For Oregon, the Company rate base amount is allocated to Oregon using a general allocator. Cascade cannot directly assign inventory held in rate base to an individual state until the materials and supplies held in rate base has actually been used, installed, or consumed.[3] I have an outstanding data request regarding the inventory level in rate base for the calendar years 2015 and 2016 to determine whether the 2018 test year inventory amount appears reasonable.

**Q. What is your adjustment based on these values?**

A. None at this time.

**Q. Does this include your testimony?**

A. Yes.

[3] See Exhibit 1004/Staff, Zarate/187.

CASE: UG 347
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1001

# Witness Qualifications Statement

# September 27, 2018

# 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 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:

- Six years as 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 delivery, and investigating property theft.

CASE: UG 347
WITNESS: KATHY ZARATE

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1002

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

**Request No. 200**

Date prepared: 7/24/2018

Preparer: Tony Durado

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 200**

Explain why costs related to the low income programs are capitalized and included in the rate base. Please provide the names of any of the low-income programs, descriptions of each program, such as LIRAP, CAT or winter Help, and listing of FERC capital and expense accounts where costs were recorded.

**Response:**

No OR Low-Income Programs are capitalized nor included in rate base.

Cascade's Low-Income Assistance Programs for Oregon consist of Public Purpose and Winter Help. Customers in Oregon contribute to the Public Purpose fund through a Public Purpose Charge on their bill each month. These funds are used for conservation and renewable energy projects, schools, low-income weatherization, low-income housing, and low-income utility bill assistance. Winter Help is a Cascade Natural Gas program funded by customer donations and a $50,000 Company contribution.

- Public Purpose Funds billed at 4.85% of revenues in OR Rate Classes 101, 104, 105, 111, and 170, which are collected and held in separate FERC 242 Liability Accounts. These funds are allocated as follows:
    - 83.0% to Energy Trust of Oregon (ETO)
    - 15.13% to Weatherization Programs
        - Oregon Low-Income Energy Conservation Program (OLIEC)
        - Conservation Achievement (CAT)
    - 01.87% to Low Income Bill Pay Assistance (OLIBA)
- Cascade's Winter Help Program.

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

- Consists of $50,000 per year annual grant from Cascade Natural Gas and Customer Donations, collected and held in a separate FERC 242 Liability Account.

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

**Request No. 201**

Date prepared: 7-23-18

Preparer: Tony Durado

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 201**

In an MS Excel Spreadsheet, please provide for each FERC account entry, the name of the low-income program, date of costs recorded, total company and Oregon allocated amounts, and basis for the Oregon-allocation factor.

**Response:**

All Public Purpose Funds collected from Oregon Customers are held in separate FERC 242 Liability Accounts, and as such there is no Oregon allocation.

Corporate Donations and Customer Contributions to Cascade's Winter Help Program are held in a separate FERC 242 Liability Account and also have no Oregon allocation factor.

For base year revenue and program cost details, summarized by program, please see attached: OPUC-201.xlsx

# STAFF EXHIBIT 1002

# OPUC-201

# IS PROVIDED IN ELECTRONIC FORMAT ONLY

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

**Request No. 202**

Date prepared: July 17, 2018

Preparer: Maryalice Peters

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 202**

Referring to Cascade's Excel workbook, "Exhibit 301-306-Peters Workpapers.xlsx", and the Company's responses to Staff's SDR Nos. 119, 93, and 57, Staff has noted a few discrepancies regarding the application of the Oregon allocated percentage. From the response to SDR No. 119, Staff infers that the Company was using 24.96 percent as the allocation factor for its 2017 actuals/base year and is using 25.15 percent for the 2018 test year allocation. Please state whether this assumption is correct.

**Response:**

That is correct.

**Cascade Natural Gas**
**Oregon Public Utility Commission**
**DR-201**

# Energy Trust of Oregon Liability

| | | Jan-17 | Feb-17 | Mar-17 | Apr-17 | May-17 | Jun-17 | Jul-17 | Aug-17 | Sep-17 | Oct-17 | Nov-17 | Dec-17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Begining GL balance | (426,857.71) | (426,857.71) | (466,233.79) | (363,806.65) | (258,024.56) | (190,038.94) | (165,135.39) | (51,232.39) | (66,649.78) | (66,150.94) | (88,409.03) | (214,415.10) | (265,440.32) |
| Public Purpose Funds (PPF) Billed to Customers | | (587,651.62) | (470,694.91) | (408,596.98) | (248,465.81) | (214,934.04) | (132,002.23) | (84,737.71) | (84,802.79) | (79,035.09) | (153,904.21) | (236,442.92) | (354,930.37) |
| Public Purpose Funds (PPF)-Accrual for Unbilled Revenue | | (354,590.28) | (298,722.42) | (184,335.49) | (152,494.55) | (125,779.01) | (52,170.59) | (43,383.94) | (33,948.64) | (55,660.44) | (146,167.42) | (212,390.30) | (376,920.29) |
| Public Purpose Funds (PPF)-Reversal of Prior month Accrual | | 410,676.62 | 354,590.28 | 298,722.42 | 184,335.49 | 152,494.55 | 125,779.01 | 52,170.59 | 43,383.94 | 33,948.64 | 55,660.44 | 146,167.42 | 212,390.30 |
| Bad Debt Portion of Public Purpose Funds (PPF) | | 1,754.16 | 1,410.40 | 1,000.32 | 671.53 | 564.65 | 175.18 | 212.67 | 195.97 | 282.08 | 757.67 | 1,029.07 | 1,818.11 |
| Public Purpose Funds (PPF) Allocated to Other Programs | | 63,577.33 | 49,610.00 | 35,185.17 | 25,914.40 | 22,518.46 | 6,986.24 | 9,088.61 | 9,020.58 | 12,055.78 | 29,238.42 | 36,196.41 | 62,117.07 |
| Payment to Energy Trust of Oregon **(Prior month balance)** | | 426,857.71 | 466,233.79 | 363,806.65 | 258,024.56 | 190,038.94 | 165,135.39 | 51,232.39 | 66,649.78 | 66,150.94 | 88,409.03 | 214,415.10 | 265,440.32 |
| **Ending G/L Balance** | **(426,857.71)** | (466,233.79) | (363,806.65) | (258,024.56) | (190,038.94) | (165,135.39) | (51,232.39) | (66,649.78) | (66,150.94) | (88,409.03) | (214,415.10) | (265,440.32) | (455,525.18) |

## Oregon Low Income Bill Pay Assisstance

| | | Jan-17 | Feb-17 | Mar-17 | Apr-17 | May-17 | Jun-17 | Jul-17 | Aug-17 | Sep-17 | Oct-17 | Nov-17 | Dec-17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Begining GL balance | (53,991.22) | (53,991.22) | (59,874.42) | (58,810.67) | (54,182.48) | (50,772.05) | (43,495.12) | (35,743.75) | (33,543.46) | (31,513.37) | (31,839.68) | (34,578.84) | (36,912.69) |
| Program Revenue from Customer Billing | | (7,629.28) | (5,953.20) | (4,222.22) | (3,109.73) | (2,702.22) | (838.35) | (1,090.63) | (1,082.47) | (1,446.69) | (3,508.61) | (4,343.57) | (7,454.05) |
| Pmts to Community Agencies (Admin Fees) | | 482.00 | 317.80 | 1,393.20 | 1,585.40 | 1,122.60 | 1,822.40 | 1,369.60 | 411.38 | 604.00 | 190.47 | 306.00 | 582.60 |
| Program Payments to Customers' Accounts | | 1,589.00 | 6,966.00 | 7,758.88 | 5,219.00 | 9,112.00 | 6,979.91 | 2,133.44 | 2,863.06 | 703.34 | 775.00 | 1,894.00 | 2,245.00 |
| Interest Income on Unspent Balance | | (324.92) | (266.85) | (301.67) | (284.24) | (255.45) | (212.59) | (212.12) | (161.88) | (186.96) | (196.02) | (190.28) | (204.31) |
| **Ending G/L Balance** | **(53,991.22)** | (59,874.42) | (58,810.67) | (54,182.48) | (50,772.05) | (43,495.12) | (35,743.75) | (33,543.46) | (31,513.37) | (31,839.68) | (34,578.84) | (36,912.69) | (41,743.45) |

**Oregon Low Income Energy Conservation**

| | | Jan-17 | Feb-17 | Mar-17 | Apr-17 | May-17 | Jun-17 | Jul-17 | Aug-17 | Sep-17 | Oct-17 | Nov-17 | Dec-17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Begining GL balance | (179,530.24) | (179,530.24) | (231,195.52) | (270,751.73) | (280,340.29) | (295,638.68) | (306,835.33) | (275,539.91) | (280,474.76) | (287,558.40) | (297,749.92) | (313,552.63) | (344,971.92) |
| Program Revenue Transferred from ETO Liability | | (55,948.05) | (43,656.80) | (30,962.95) | (22,804.67) | (19,816.24) | (6,147.89) | (7,997.98) | (7,938.11) | (10,609.09) | (25,729.81) | (31,852.84) | (54,663.02) |
| Program Payments to Community Agencies | | 3,974.24 | 4,077.70 | 21,341.80 | 7,582.02 | 8,758.79 | 37,479.67 | 1,938.40 | 400.00 | - | 9,387.04 | - | 690.00 |
| Interest expense on unused balance | | 308.53 | 22.89 | 32.59 | (75.74) | (139.20) | (36.36) | 1,124.73 | 454.47 | 417.57 | 540.06 | 433.55 | 303.63 |
| **Ending G/L Balance** | **(179,530.24)** | (231,195.52) | (270,751.73) | (280,340.29) | (295,638.68) | (306,835.33) | (275,539.91) | (280,474.76) | (287,558.40) | (297,749.92) | (313,552.63) | (344,971.92) | (398,641.31) |

**Cascade Natural Gas**
**Oregon Public Utility Commission**
**DR-201**

## Conservation Achievement

| | | Jan-17 | Feb-17 | Mar-17 | Apr-17 | May-17 | Jun-17 | Jul-17 | Aug-17 | Sep-17 | Oct-17 | Nov-17 | Dec-17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Begining GL balance | 209,845.10 | 209,845.10 | 216,557.82 | 221,567.82 | 256,799.52 | 270,193.50 | 280,635.92 | 378,131.27 | 382,430.31 | 382,430.31 | 382,430.31 | 399,232.42 | 399,232.42 |
| Program Payments to Community Agencies | | 6,712.72 | 5,010.00 | 35,231.70 | 13,393.98 | 10,442.42 | 97,495.35 | 4,299.04 | - | - | 16,802.11 | - | 3,995.00 |
| **Ending G/L Balance** | **209,845.10** | 216,557.82 | 221,567.82 | 256,799.52 | 270,193.50 | 280,635.92 | 378,131.27 | 382,430.31 | 382,430.31 | 382,430.31 | 399,232.42 | 399,232.42 | 403,227.42 |

## Winter Help Program

| | | Jan-17 | Feb-17 | Mar-17 | Apr-17 | May-17 | Jun-17 | Jul-17 | Aug-17 | Sep-17 | Oct-17 | Nov-17 | Dec-17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Begining GL balance | (91,357.36) | (91,357.36) | (99,475.48) | (99,878.63) | (95,316.81) | (89,474.65) | (84,131.54) | (83,560.54) | (83,009.70) | (80,200.09) | (81,031.32) | (86,893.51) | (94,971.63) |
| Customer-Winter Help Pledges from Customers | | (786.00) | (870.00) | (982.48) | (949.52) | (934.93) | (666.40) | (958.07) | (896.99) | (820.00) | (1,023.07) | (837.93) | (689.51) |
| Customer-Charitable Contributions | | (6,252.96) | (5,483.15) | (4,373.70) | (3,753.71) | (4,173.88) | (3,894.08) | (4,413.94) | (5,054.96) | (6,117.97) | (5,631.30) | (4,560.50) | (9,268.33) |
| Corporate Contribution | | (10,000.00) | (10,000.00) | (10,000.00) | (7,000.00) | | | | | | (3,000.00) | (4,500.00) | (5,500.00) |
| Program Costs-Payments to Agencies | | 435.00 | 825.00 | 1,320.00 | 1,425.00 | 1,230.00 | 690.00 | 420.00 | 345.00 | 615.00 | 435.00 | 285.00 | 195.00 |
| Program Costs-Funds Credited to Customer Accts | | 8,485.84 | 15,125.00 | 18,598.00 | 16,120.39 | 9,221.92 | 4,441.48 | 5,502.85 | 8,416.56 | 5,491.74 | 3,357.18 | 1,535.31 | 7,355.43 |
| Ending G/L Balance | **(91,357.36)** | (99,475.48) | (99,878.63) | (95,316.81) | (89,474.65) | (84,131.54) | (83,560.54) | (83,009.70) | (80,200.09) | (81,031.32) | (86,893.51) | (94,971.63) | (102,879.04) |

CASE: UG 347
WITNESS: MING PENG

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1100
# Depreciation, Reserve and AFUDC

## Opening Testimony

## September 27, 2018

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

A. My name is Ming Peng. 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 Peng/1101.

**Q. What is the purpose of your testimony?**

A. I discuss my review of the depreciation expense and the accumulated depreciation (depreciation reserves) components in Cascade Natural Gas Corporation's (CNGC or Company) general rate case, as well as the revenue requirement for this rate case as documented by Company witness Maryalice Peters in CNGC/300. I also review the Allowance for Funds Used During Construction (AFUDC) portion of revenue requirement for this rate case.

**Q. What exhibits are included as part of your testimony?**

A. I have prepared the following exhibits: Exhibit Peng/1101, Witness Qualification Statement, and Exhibit Peng/1102, CNGC Response to Staff Data Request (DR) Nos. 139-147. Exhibit 1102 contains CNGC's analysis, in responses to Staff data requests. The response files, in Excel format, contain links to internal and external references, support Staff's recommendations.

**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 depreciation 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 keep

[1] NARUC, *Public Utility Depreciation Practices*, p.318 (1996).

> 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 depreciation rates determined?**

A. To develop depreciation rates, it is necessary to estimate the (1) combination of survivor curve-service life (Curve-Life, Iowa Curve, Survivor curves)[2] of utility property, and (2) 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 depreciation rates did CNGC use in its test year revenue requirement?**

A. CNGC filed its most recent depreciation study in April 2015, which the Commission reviewed in Docket No. UM 1727. At the conclusion of that docket, the Commission issued Order No. 15-315 authorizing the Curve-Life and Net Salvage parameters for “each plant account” (FERC account), from which depreciation parameters and depreciation rates are derived for each account. To determine test year expense in this case, CNGC used the

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[2] "Survivor curves" 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 is the difference between gross salvage and cost of removal. Net salvage is positive when gross salvage exceeds the cost of removal and reduces the revenue requirement. Conversely, net salvage is negative when cost of removal exceeds gross salvage and increases the revenue requirement.

Commission authorized depreciation parameters and depreciation rates in Order 15-315.

**Q. Has CNGC used the authorized depreciation parameters, depreciation rates and asset remaining life in Order No. 15-315?**

A. Yes. CNGC complied with the order by using authorized depreciation parameters that are survivor curve-projection life, net salvage rates, net plant depreciation rates and remaining service life by FERC accounts.

**Q. How did you analyze the Company's proposed depreciation expense, and what information did you review?**

A. To confirm that the depreciation expense was properly calculated using the authorized depreciation parameters in Commission Order No. 15-315 (UM 1727), I sent the Company data requests asking CNGC to insert data links to its Excel work paper 301-306, and asked CNGC to verify such data as (1) plant balance, (2) depreciation rates, (3) depreciation expenses, and (4) depreciation reserves in Docket No. UM 1727, Order No. 15-315. I further requested that the numbers in data responses tie to the revenue requirement model to allow Staff to trace the data calculation from proposed data sources.

Upon receiving the Company's responses, I verified the Company's calculations by:

(1) Reviewing how the Company calculated depreciation expense using the depreciation parameters authorized in Order 15-315; and,

(2) Conducting several phone conferences with the Company to gain a better understanding of the Company's depreciation adjustments.

**Q. Did you find errors in the Company's original filing with respect to depreciation?**

A. No. In its responses to Staff DR Nos. 139-147, the Company demonstrated data links and calculations in spreadsheets that complied with the Commission authorized depreciation rates in Order 15-315.

**ISSUE 2. DEPRECIATION EFFECT ON REVENUE REQUIREMENT**

**Q. 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.[4]

**Q. What is the relationship between depreciation and 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) (RR is measured by cost-of-service), a basic formula is followed:[5]

RR = O&M Expense + "Depreciation" + Taxes + Return% x Rate Base

Rate Base = Gross Plant – "Accumulated Depreciation" – Accumulated Deferred Income Taxes + Working Capital

[4] NARUC, *Public Utility Depreciation Practices,* p.195 (1996).

[5] Federal Energy Regulatory Commission, *Cost-of-Service Rates Manual*, pp. 6-7 (1999), 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. How are depreciation parameters used in determining the utility's revenue requirement?**

A. In a general rate case filing, the depreciation expense is calculated by using the Commission's authorized depreciation parameters, from which depreciation rates are derived and traditional FERC classification of generation, transmission, distribution, and general plant assets.

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 is 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. How is depreciation expense calculated in revenue requirement?**

A. Depreciation expense, in revenue requirement, is determined by three factors: (1) depreciation rates, (2) plant in service, and (3) Oregon cost allocation factor between states, if any. As already noted, depreciation rates were determined in OPUC Order No. 15-315, UM 1727.

**Q. Please explain if the depreciation expense in this testimony is final.**

A. The expense is final assuming that no additional errors are present in the Company's filing and no other adjustments are made to rate base or

allocations between jurisdictions. If, however, any adjustments are made to plant in service or the cost allocation factor between states, the final depreciation expense and accumulated depreciation would change accordingly.

## ISSUE 3. RESERVES – ACCUMULATED DEPRECIATION

**Q. What is the depreciation reserve?**

A. Depreciation reserve is, at a point in time, the total amount of recorded depreciation, retirements, gross salvage, cost of removal, and other adjustments. This is also called the accumulated provision for depreciation or accumulated depreciation/amortization reserve. Reserve is affected by depreciation expenses (for tangible assets), amortization expenses (for intangible assets), retirements, gross salvage, cost of removal, and other adjustments.

**Q. Have you reviewed CNGC's depreciation and amortization reserve?**

A. Yes. I reviewed whether depreciation reserve (accumulated depreciation – tangible asset in rate base) is properly filed.

**Q. How did you review CNGC's reserve?**

A. Generally speaking, a depreciation reserve is the accumulated depreciation expenses. I reviewed the Company's calculations and verified the links on the Company's workpapers. I also examined the total amount of recorded depreciations, retirements, gross salvage, cost of removal, and other adjustments to determine the Company's net book plant:

1. Accumulated depreciation is the cost of the investment in gross plant that is recovered through the cost-of-service as depreciation expense.

2. The depreciation expense is accumulated and is subtracted from the gross plant to reduce the remaining investment to be recovered.

3. The remaining balance is the net book plant. The net book plant represents the portion of gross plant that is not depreciated.

**Q. What are the findings of CNGC's depreciation and amortization reserve from your review?**

A. I examined the reserve in rate-base and the depreciation in expense in the revenue requirement equation. CNGC's data responses to Staff DR Nos. 139-147, along with an Excel calculation, shows that the accumulated depreciation reserve as of December 31, 2018 is $109.4 million. The detailed numbers verification including the following:

(1) There was an upward adjustment of $240,129 to the 2017 base year depreciation expense to arrive at the 2018 test year depreciation expense.

(2) There was a $627,614 increase in depreciation expense due to the increase of "plant in service" for $24,552,055.

**Q. Do you propose the adjustment to reserve?**

A. No. Based on my careful review, I found the reserve filing to be reasonable and was consistent with FERC accounting requirement and OPUC Order No. 15-315, UM 1727.

## ISSUE 4. 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 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."

**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 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 find a deficiency in the Company's capitalization practices and therefore, I did not make any recommendations for corrective action to those practices.

## ISSUE 5. 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 calculation of its AFUDC rate?**

A. Yes. I reviewed the company calculations of its AFUDC rates based on FERC's AFUDC rate formulas that I mentioned above.

**Q. Please describe whether CNGC complied with guidance regarding the capitalization of assets based on FERC's and the OPUC regulations in this filing?**

A. FERC has prescribed two formulas for calculating maximum allowable AFUDC rates.

Debt: One formula determines the maximum rate that can be used to capitalize an allowance for borrowed funds (i.e., debt) used for construction purposes.

Common Equity: 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.

Staff's **DR No. 141** asked: "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."

CNGC responded: "The Company's AFUDC calculation does comply with FERC AFUDC accounting. See attachment OPUC-141.pdf for the 2018 calculation and a narrative of the calculation, which was provided in the response to question Staff DR No. 143."

Staff's **DR No. 142** 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: "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."

Staff's **DR No. 143** 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."

For Borrowed Funds, 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

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."

For Other Funds, CNGC responded: "**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 an 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's **DR No. 144** asked: "Has the Company put its CWIP into the rate base for capital recovery?"

CNGC responded: "No, the Company does not include CWIP in rate base."

Staff's **DR No. 145** asked: "Please provide the CWIP/AFUDC information. Include:

a. Cascade's capitalized AFUDC including the total dollar amount for its projects in Excel worksheets. Include 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.

CNGC responded: "The OPUC-145.xlsx spreadsheet has detailed calculations."

Staff's data request **DR No. 146** asked: "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."

CNGC responded: "It is the Company's policy and practice to stop accruing AFUDC in the month following the actual in-service date."

**Q. Is Company's calculation of its AFUDC rates in a manner consistent with FERC rules and regulatory guide?**

A. Yes. In response to Staff DR Nos. 139-147, along with the Excel calculation files, CNGC demonstrated its calculations of its monthly 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. Have you made adjustment to CNGC's AFUDC rate?**

A. No. The Company's AFUDC policy and calculation are consistent with regulatory guidance.

**ISSUE 6. AUTHORIZED CAPITAL STRUCTURE AND RATE OF RETURN**

**Q. What is Oregon PUC authorized rate of return and capital structure? Has CNGC complied with this debt/equity structure when calculating AFUDC?**

A. Staff's **DR No.147** asked CNGC to 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 2018;
c. Current Oregon Authorized Capital structure: Debt/Equity Ratio;
d. The Company's Capital structure: Debt/Equity Ratio from 2015 through 2018; and
e. The current Oregon Authorized Return on Equity."

CNGC responded as follows:

a. Current Oregon authorized WACC: 7.284%
b. WACC figures per Spring Earnings Reviews:
    a. 2015: 6.76%
    b. 2016: 6.87%
    c. 2017: 6.48%
    d. 2018: 5.85%
c. Current Oregon Authorized Capital structure: 51% long term debt and 49% equity.
d. Debt/Equity Ratio by year:
    i. 2015: 53% / 47%
    ii. 2016: 52% /48%
    iii. 2017: 50.8% / 49.2%
    iv. 2018 (projected): 49.8% / 50.2%
e. Current Oregon Authorized Return on Equity: 9.400%

After the review, I found CNGC has used the Commission authorized rate of return (7.284%) and capital structure (51% debt / 49% equity) when calculating AFUDC, and I proposed no adjustment for this issue.

**Q. Does this conclude your testimony?**

A. Yes.

CASE: UG 347
WITNESS: MING PENG

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1101

# Witness Qualifications Statement

# September 27, 2018

# WITNESS QUALIFICATIONS STATEMENT

NAME: Ming Peng (Ms.)

EMPLOYER: Public Utility Commission of Oregon

TITLE: Senior Economist
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

C.R.R.A. Certified Rate of Return Analyst
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 19 years since January 1999. My roles include:

<u>Expert Witness, Case Manager, Economist, Policy Analyst, Econometrician, and Principal Analyst</u>
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.

<u>Principal Analyst & Case Manager, Settlement Lead / Negotiator for Depreciation and Ratemaking:</u>
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 10 years. This 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) in this time period.

In this position, I investigate, analyze and calculate "Energy Asset Retirement Cost & Impact" and "Power Plant Decommissioning Cost & Impact" on Customer Rates. I review, calculate, analyze 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 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 present position, I was a lead analyst and case manager for cost of 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. In most cases the Commission incorporated 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 "Boardman to Hemingway Transmission Line Project (B2H, a 500-kV power line from NE Oregon to SW Idaho)" to the Commission for the decision-making that including cost and benefit list, pros and cons list, alternatives, and the legal risks.

Clean Energy – Dollar Impact on Customer Rates: I have analyzed and calculated the rate impact and comparative advantage of clean energy.

General Ratemaking: I have forecasted electric generation fuel prices, determined costs and benefits of property sales, and forecasted loads. My weather normalizations have been used in both rate cases and in integrated resource planning.

Survey Sampling Design: Results of my statistical sampling and procurement design are incorporated into my revenue requirement testimony in Commission Docket No. UM 1288.

Auditing: I audited energy utility cost of capital and finance component in operation audits. My "Interest Rate and Late Payment Charge" Survey and Analysis are published annually for the State of 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 347
WITNESS: MING PENG

# PUBLIC UTILITY COMMISSION
# OF
# OREGON

# STAFF EXHIBIT 1102

## Exhibits in Support
## Of Opening Testimony

## September 27, 2018

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

**Request No. 139**

Date prepared: July 9, 2018

Preparer: Maryalice Peters

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 139**

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, (5) Oregon Allocation Factors, which are all tied to the Revenue Requirement Excel Model.

In addition, please provide, and as appropriate, 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 Expense link to Depreciation Rates in Order No. 15-315, UM 1727; and
d. Accumulated Depreciation and Amortization.

**Response:**

a. See spreadsheet OPUC-139 Peters Workpapers Exhibits 301-306.xlsx

b. See tab Exh-2018 Plant additions in OPUC-139 Peters Workpapers Exhibits 301-306.xlsx.

c. Attached as "OPUC-139c.xlsx" is a copy of the referenced tab "13 Month Depr Exp". Column N in the attached file is transferred to the "Depreciation Expense Adj" tab in Peters Workpapers Exhibits 301-306.

d. The depreciation rates shown in Column D in Peters Exhibit 305-2018 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.

# STAFF EXHIBIT 1102

## OPUC-139 AND OPUC-139 c

## ARE PROVIDED IN ELECTRONIC FORMAT ONLY

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

**Request No. 140**

Date prepared: July 9, 2018

Preparer: Paul Bienek

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 140**

Please provide the Company's 2018 to 2020 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:**

1. See OPUC-140.xlsx.

2. Will not add up to total in the Company's Revenue Requirement mode, they are independent calculations.

# STAFF EXHIBIT 1102

# OPUC-140

# IS PROVIDED IN ELECTRONIC FORMAT ONLY

CASCADE NATURAL GAS CO
AFUDC CALCULATION
ANNUAL AFUDC RATE
Mar-18

FACTORS:

| | |
|---|---|
| S = AVERAGE SHORT-TERM DEBT | 25,153,424.00 |
| s = SHORT-TERM EFFECTIVE RATE | 4.45 |
| D = LONG TERM DEBT | 214,431,000.00 |
| d = LONG-TERM INTEREST RATE | 5.27 |
| P = PREFERRED STOCK | 0.00 |
| p = PREFERRED STOCK COST RATE | 0.00 |
| C = COMMON EQUITY | 224,513,350.53 |
| c = COMMON EQUITY RATE | 9.40 |
| W = AVERAGE WORK-IN-PROGRESS | 25,597,241.00 |

A1 = s(S/W) + d(D/D+P+C) * (1 - S/W) BORROWED FUNDS

Ae = (1-S/W) * (p(P/D+P+C) + c(C/D+P+C)) OTHER FUNDS

BORROWED FUNDS:

S/W = 0.9827 D/D+P+C = 0.4885

A1 = ( 0.0445 X 0.9827 ) + ( 0.0527 X 0.4885 ) X ( 1 - 0.9827 )

A1 = 0.0437 + ( 0.0257 X 0.0173 )

A1 = 0.0437 + 0.0004

A1 = 0.0441 OR 4.41 %

OTHER FUNDS:

S/W = 0.9827 P/D+P+C = 0.0000 C/D+P+C = 0.5115

Ae = ( 1.0000 - 0.9827 ) X ( 0.0000 X 0.0000 ) + ( 0.094 X 0.5115 )

Ae = 0.0173 X ( 0.0000 + 0.0481 )

Ae = 0.0173 X 0.0481

Ae = 0.0008 OR 0.08 %

AFUDC RATE: 4.49%

MONTHLY AFUDC RATE
ANNUAL RATE /12 = MONTHLY RATE

ALLOCATE TO TOTAL FUNDS:

| | |
|---|---|
| BORROWED FUNDS | 0.003675 |
| OTHER FUNDS | 0.000067 |

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

**Request No. 142**

Date prepared: July 3, 2018

Preparer: Mike Bakke

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 142**

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:**

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 347

**Request No. 143**

Date prepared: July 3, 2018

Preparer: Mike Bakke

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 143**

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:**

**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 347

**Request No. 144**

Date prepared: July 5, 2018

Preparer: Paul Bienek

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 144**

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 347

**Request No. 145**

Date prepared: July 10, 2018

Preparer: Jordan Harris

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 145**

Please provide the CWIP/AFUDC information. Include:

a. Cascade's capitalized AFUDC including the total dollar amount for its projects in Excel worksheets. Include 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-145.xlsx.

# STAFF EXHIBIT 1102

# OPUC-145

# IS PROVIDED IN ELECTRONIC FORMAT ONLY

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

**Request No. 146**

Date prepared: July 5, 2018

Preparer: Paul Bienek

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 146**

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.

# CASCADE NATURAL GAS CORPORATION
## Oregon Public Utility Commission
## General Rate Case
## UG 347

Due Date: July 10, 2018

**Request No. 147**

Date prepared: 07/09/2018

Preparer: Isaac Myhrum

Contact: Pamela Archer

Telephone: (509)-734-4591

**OPUC DATA REQUEST NO. 147**

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 2018;
c. Current Oregon Authorized Capital structure: Debt/Equity Ratio;
d. The Company's Capital structure: Debt/Equity Ratio from 2015 through 2018; and
e. The current Oregon Authorized Return on Equity.

**Response:**

a. Current Oregon authorized WACC: 7.284%
b. WACC figures per Spring Earnings Reviews:
    a. 2015: 6.76%
    b. 2016: 6.87%
    c. 2017: 6.48%
    d. 2018: 5.85%[1]
c. Current Oregon Authorized Capital structure: 51% long term debt and 49% equity.
d. Debt/Equity Ratio by year[2]:
    i. 2015: 53% / 47%
    ii. 2016: 52% /48%
    iii. 2017: 50.8% / 49.2%
    iv. 2018 (projected): 49.8% / 50.2%
e. Current Oregon Authorized Return on Equity: 9.400%

[1] Exhibit CNGC/301 Peters
[2] Exhibit CNGC/201 Parvinen